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, 2015

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 16, 2015
Pepco Holdings	253,617,191 ($.01 par value)
Pepco	100 ($.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.

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GLOSSARY OF TERMS

Term	Definition
2014 Form 10-K	The Annual Report on Form 10-K for the year ended December 31, 2014, 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
Conectiv Energy	Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries, which were sold to Calpine in July 2010
Contract EDCs	Pepco, DPL and BGE, the Maryland utilities required by the MPSC to enter into a contract for new generation
CTA	Consolidated tax adjustment
DC PLUG	District of Columbia Power Line Undergrounding initiative
DCPSC	District of Columbia Public Service Commission
DC Settlement Agreement	The Nonunanimous Full Settlement Agreement and Stipulation entered into on October 6, 2015, by Exelon, PHI and Pepco, and certain of their respective affiliates with the District of Columbia Government, the Office of the People's Counsel and other parties, regarding the District of Columbia Merger approval proceedings
DDOT	District of Columbia Department of Transportation
DDOT surcharge	A volumetric surcharge for the District of Columbia to recover the costs associated with the DC PLUG bond issuance
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
DEMEC	Delaware Municipal Electric Corporation, Inc.
DOE	U.S. Department of Energy
DOEE	District of Columbia Department of Energy and Environment
DOJ	U.S. Department of Justice
DPL	Delmarva Power & Light Company
DPSC	Delaware Public Service Commission
DRP	Direct Stock Purchase and Dividend Reinvestment Plan
DSEU	Delaware Sustainable Energy Utility
EDCs	Electric distribution companies
EmPower Maryland	A Maryland demand-side management program for Pepco and DPL
EPA	U.S. Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934, as amended
Exelon	Exelon Corporation, a Pennsylvania corporation
FASB	Financial Accounting Standards Board
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission
FLRP	Forward Looking Rate Plan filed by DPL in Delaware
FPA	Federal Power Act
FS	Feasibility study
GAAP	Accounting principles generally accepted in the United States of America

Term	Definition
GCR	Gas Cost Rate
GWh	Gigawatt hour
HSR Act	Hart-Scott-Rodino Antitrust Improvements Act of 1976
IRS	Internal Revenue Service
Joint Applicants	Exelon, PHI and Pepco, and certain of their respective affiliates
LIBOR	London Interbank Offered Rate
Merger	Merger of the Merger Sub with and into PHI
Merger Agreement	Agreement and Plan of Merger, dated April 29, 2014 among Exelon, Merger Sub and PHI
Merger Sub	Purple Acquisition Corp., a Delaware corporation and an indirect, wholly owned subsidiary of Exelon
Motion to Reopen	The Motion of Joint Applicants to Reopen the Record in Formal Case No. 1119 to Allow for Consideration of the DC Settlement Agreement
MPSC	Maryland Public Service Commission
MW	Megawatt
New Jersey Societal Benefit Program	A New Jersey statewide public interest program that is intended to benefit low income customers and address other public policy goals
NJBPU	New Jersey Board of Public Utilities
NJ SOCA Law	The New Jersey law under which the SOCAs were established
NPDES	National Pollutant Discharge Elimination System
NUGs	Non-utility generators
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
Regulatory Termination	If the Merger Agreement is terminated under certain circumstances due to the failure to obtain regulatory approvals or the breach by Exelon of its obligations in respect of obtaining regulatory approvals
Reporting Company	PHI, Pepco, DPL or ACE
RI/FS	Remedial investigation and feasibility study
RI	Remedial investigation
ROE	Return on equity
RPS	Renewable Energy Portfolio Standards
SEC	Securities and Exchange Commission
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
Subscription Agreement	Subscription Agreement, dated April 29, 2014, between Exelon and PHI

Term	Definition
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
VDEQ	Virginia Department of Environmental Quality
VIE	Variable interest entity
VSCC	Virginia State Corporation Commission

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:

- Certain risks and uncertainties associated with the proposed merger (the Merger) of an indirect, wholly owned subsidiary of Exelon Corporation, a Pennsylvania corporation (Exelon) with and into Pepco Holdings, including, without limitation:
    - The inability of Pepco Holdings or Exelon to obtain regulatory approvals required for the Merger;
    - Delays caused by required regulatory approvals, including the reconsideration process in the District of Columbia, and the review and approval of the Merger on the terms set forth in the settlement agreement among PHI, Exelon, the District of Columbia government and other parties, which may delay the Merger or cause the companies to abandon the Merger;
    - The inability of Pepco Holdings or Exelon to satisfy conditions to the closing of the Merger;
    - Unexpected costs, liabilities or delays that may arise from the Merger, including as a result of stockholder litigation;
    - Negative impacts on the businesses of Pepco Holdings and its utility subsidiaries as a result of uncertainty surrounding the Merger, including continuing delays in filing rate cases due to the restrictions contained in the Merger Agreement; and
    - Future regulatory or legislative actions impacting the industries in which Pepco Holdings and its subsidiaries operate, which actions could adversely affect Pepco Holdings and its utility subsidiaries.
- 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 previously established by the Federal Energy Regulatory Commission (FERC) for transmission services provided by Pepco, DPL and ACE; and (ii) other possible disallowances related to recovery of costs (including capital costs and advanced metering infrastructure (AMI) costs) and expenses or delays in the recovery of such costs;

- 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 and other new technologies;
- General economic conditions, including the impact on energy use caused by an economic downturn or recession, or by changes in the level of commercial activity in a particular region or service territory, or affecting a particular business or industry located therein;
- 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 (NERC) 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 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, 2014 (2014 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
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(millions of dollars, except per share data)			
Operating Revenue	$ 1,362	$ 1,313	$ 3,873	$ 3,760
Operating Expenses				
Fuel and purchased energy	580	545	1,651	1,622
Other services cost of sales	37	54	131	161
Other operation and maintenance	257	242	772	679
Depreciation and amortization	178	145	494	410
Other taxes	114	109	327	315
Deferred electric service costs	13	(1)	34	30
Impairment loss	—	53	—	53
Total Operating Expenses	1,179	1,147	3,409	3,270
Operating Income	183	166	464	490
Other Income (Expenses)				
Interest expense	(71)	(68)	(210)	(200)
Other income	28	15	49	42
Total Other Expenses	(43)	(53)	(161)	(158)
Income Before Income Tax Expense	140	113	303	332
Income Tax Expense	49	34	106	125
Net Income	$ 91	$ 79	$ 197	$ 207
Basic and Diluted Share Information				
Weighted average shares outstanding – Basic (millions)	254	252	253	251
Weighted average shares outstanding – Diluted (millions)	254	252	254	252
Basic and Diluted earnings per share	$ 0.36	$ 0.31	$ 0.78	$ 0.82

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(millions of dollars)			
Net Income	$ 91	$ 79	$ 197	$ 207
Other Comprehensive Income				
Losses on treasury rate locks reclassified into income	1	—	1	—
Pension and other postretirement benefit plans	2	2	7	—
Other comprehensive income, before income taxes	3	2	8	—
Income tax expense (benefit) related to other comprehensive income	2	—	3	(1)
Other comprehensive income, net of income taxes	1	2	5	1
Comprehensive Income	$ 92	$ 81	$ 202	$ 208

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

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

	September 30, 2015	December 31, 2014
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 271	$ 14
Restricted cash equivalents	18	25
Accounts receivable, less allowance for uncollectible accounts of $58 million and $40 million, respectively	947	782
Inventories	142	141
Deferred income tax assets, net	70	50
Income taxes and related accrued interest receivable	11	9
Prepaid expenses and other	87	63
Total Current Assets	1,546	1,084
OTHER ASSETS		
Goodwill	1,406	1,407
Regulatory assets	2,294	2,409
Income taxes and related accrued interest receivable	81	81
Restricted cash equivalents	15	14
Other	178	166
Total Other Assets	3,974	4,077
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	15,989	15,465
Accumulated depreciation	(4,952)	(4,959)
Net Property, Plant and Equipment	11,037	10,506
TOTAL ASSETS	$ 16,557	$ 15,667

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

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

	September 30, 2015	December 31, 2014
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 1,128	$ 729
Current portion of long-term debt and project funding	300	431
Accounts payable	205	174
Accrued liabilities	300	313
Capital lease obligations due within one year	11	10
Taxes accrued	40	41
Interest accrued	76	47
Liabilities and accrued interest related to uncertain tax positions	6	6
Other	274	314
Total Current Liabilities	2,340	2,065
DEFERRED CREDITS		
Regulatory liabilities	348	343
Deferred income tax liabilities, net	3,415	3,266
Investment tax credits	14	16
Pension benefit obligation	443	396
Other postretirement benefit obligations	236	265
Liabilities and accrued interest related to uncertain tax positions	2	2
Other	196	193
Total Deferred Credits	4,654	4,481
OTHER LONG-TERM LIABILITIES		
Long-term debt	4,845	4,441
Transition bonds issued by ACE Funding	138	171
Long-term project funding	4	8
Capital lease obligations	45	50
Total Other Long-Term Liabilities	5,032	4,670
COMMITMENTS AND CONTINGENCIES (NOTE 15)		
PREFERRED STOCK		
Series A preferred stock, $.01 par value, 18,000 shares authorized, 18,000 and 12,600 shares outstanding, respectively	183	129
EQUITY		
Common stock, $.01 par value, 400,000,000 shares authorized, 253,590,612 and 252,728,684 shares outstanding, respectively	3	3
Premium on stock and other capital contributions	3,830	3,800
Accumulated other comprehensive loss	(41)	(46)
Retained earnings	556	565
Total Equity	4,348	4,322
TOTAL LIABILITIES AND EQUITY	$ 16,557	$ 15,667

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, 2015	Nine Months Ended September 30, 2014
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 197	$ 207
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	494	410
Deferred income taxes	109	259
Gains on sales of land	—	(9)
Impairment loss	—	53
Increase in fair value of preferred stock derivative	(15)	—
Other	(2)	4
Changes in:		
Accounts receivable	(165)	18
Inventories	(1)	(4)
Prepaid expenses	(7)	(27)
Regulatory assets and liabilities, net	(99)	(135)
Accounts payable and accrued liabilities	(12)	39
Pension benefit obligation, excluding contributions	56	36
Cash collateral related to derivative activities	4	(6)
Income tax-related prepayments, receivables and payables	11	(138)
Interest accrued	29	33
Other assets and liabilities	2	9
Net Cash From Operating Activities	601	749
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(855)	(846)
Department of Energy capital reimbursement awards received	—	4
Proceeds from sales of land	—	9
Changes in restricted cash equivalents	6	(7)
Net other investing activities	14	(4)
Net Cash Used By Investing Activities	(835)	(844)
FINANCING ACTIVITIES		
Dividends paid on common stock	(206)	(204)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation	23	29
Issuance of Series A preferred stock	54	108
Issuances of long-term debt	408	771
Reacquisitions of long-term debt	(158)	(232)
Issuances (repayments) of short-term debt, net	99	(32)
Borrowings under term loan	300	—
Repayment of term loan	—	(100)
Cost of issuances	(6)	(10)
Net other financing activities	(23)	(1)
Net Cash From Financing Activities	491	329
Net Increase in Cash and Cash Equivalents	257	234
Cash and Cash Equivalents at Beginning of Period	14	23
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 271	$ 257
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash received for income taxes, net	$ (12)	$ (1)

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	Retained Earnings	Total
BALANCE, DECEMBER 31, 2014	252,728,684	$ 3	$ 3,800	$ (46)	$ 565	$4,322
Net income	—	—	—	—	53	53
Other comprehensive income	—	—	—	1	—	1
Dividends on common stock ($0.27 per share)	—	—	—	—	(68)	(68)
Issuance of common stock:						
Original issue shares, net	153,532	—	4	—	—	4
DRP original issue shares	161,146	—	7	—	—	7
Net activity related to stock-based awards	—	—	(2)	—	—	(2)
BALANCE, MARCH 31, 2015	253,043,362	3	3,809	(45)	550	4,317
Net income	—	—	—	—	53	53
Other comprehensive income	—	—	—	3	—	3
Dividends on common stock ($0.27 per share)	—	—	—	—	(69)	(69)
Issuance of common stock:						
Original issue shares, net	155,891	—	4	—	—	4
DRP original issue shares	236,793	—	6	—	—	6
Net activity related to stock-based awards	—	—	4	—	—	4
BALANCE, JUNE 30, 2015	253,436,046	3	3,823	(42)	534	4,318
Net income	—	—	—	—	91	91
Other comprehensive income	—	—	—	1	—	1
Dividends on common stock ($0.27 per share)	—	—	—	—	(69)	(69)
Issuance of common stock:						
Original issue shares, net	154,566	—	4	—	—	4
Net activity related to stock-based awards	—	—	3	—	—	3
BALANCE, SEPTEMBER 30, 2015	253,590,612	$ 3	$ 3,830	$ (41)	$ 556	$4,348

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, to a lesser extent, 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, underground transmission and distribution construction and maintenance services, and steam and chilled water under long-term contracts.

PHI Service Company, a wholly owned 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 service agreements 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 agreements.

Agreement and Plan of Merger with Exelon Corporation

PHI entered into an Agreement and Plan of Merger, dated April 29, 2014, as amended and restated on July 18, 2014 (the Merger Agreement), with Exelon Corporation, a Pennsylvania corporation (Exelon), and Purple Acquisition Corp., a Delaware corporation and an indirect, wholly owned subsidiary of Exelon (Merger Sub), providing for the merger of Merger Sub with and into PHI (the Merger), with PHI surviving the Merger as an indirect, wholly owned subsidiary of Exelon. Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of common stock, par value $0.01 per share, of PHI (other than (i) shares owned by Exelon, Merger Sub or any other direct or indirect wholly owned subsidiary of Exelon and shares owned by PHI or any direct or indirect, wholly owned subsidiary of PHI, and in each case not held on behalf of third parties (but not including shares held by PHI in any rabbi trust or similar arrangement in respect of any compensation plan or arrangement) and (ii) shares that are owned by stockholders who have perfected and not withdrawn a demand for appraisal rights pursuant to Delaware law), will be canceled and converted into the right to receive $27.25 in cash, without interest.

In connection with entering into the Merger Agreement, as further described in Note (12), "Preferred Stock," PHI entered into a Subscription Agreement with Exelon dated April 29, 2014 (the Subscription Agreement), pursuant to which PHI issued to Exelon 9,000 originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share (the Preferred Stock), for a purchase price of $90 million on April 30, 2014. Exelon also committed, pursuant to the Subscription

Agreement, to purchase 1,800 originally issued shares of Preferred Stock for a purchase price of $18 million at the end of each 90-day period following the date of the Subscription Agreement until the Merger closes or is terminated, up to a maximum of 18,000 shares of Preferred Stock for a maximum aggregate consideration of $180 million. In accordance with the Subscription Agreement, on each of July 29, 2014, October 27, 2014, January 26, 2015, April 27, 2015 and July 24, 2015, an additional 1,800 shares of Preferred Stock were issued by PHI to Exelon for a purchase price of $18 million.

The Merger Agreement provides for certain termination rights for each of PHI and Exelon, and further provides that, upon termination of the Merger Agreement under certain specified circumstances, PHI will be required to pay Exelon a termination fee of $259 million or reimburse Exelon for its expenses up to $40 million (which reimbursement of expenses shall reduce on a dollar for dollar basis any termination fee subsequently payable by PHI), provided, however, that if the Merger Agreement is terminated in connection with an acquisition proposal made under certain circumstances by a person who made an acquisition proposal between April 1, 2014 and the date of the Merger Agreement, the termination fee will be $293 million plus reimbursement of Exelon for its expenses up to $40 million (not subject to offset). In addition, if the Merger Agreement is terminated under certain circumstances due to the failure to obtain required regulatory approvals with respect to the Merger or the breach by Exelon of its obligations in respect of obtaining such regulatory approvals (a Regulatory Termination), PHI will be able to redeem any issued and outstanding Preferred Stock at par value, and in that case, Exelon will be required to pay all documented out-of-pocket expenses incurred by PHI in connection with the Merger Agreement or the transactions contemplated thereby, up to $40 million. If the Merger Agreement is terminated, other than for a Regulatory Termination, PHI will be required to redeem the Preferred Stock at the purchase price of $10,000 per share, plus any unpaid accrued and accumulated dividends thereupon.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (i) the approval of the Merger by the holders of a majority of the outstanding shares of common stock of PHI; (ii) the receipt of regulatory approvals required to consummate the Merger, including approvals from the Federal Energy Regulatory Commission (FERC), the Federal Communications Commission (FCC), the Delaware Public Service Commission (DPSC), the District of Columbia Public Service Commission (DCPSC), the Maryland Public Service Commission (MPSC), the New Jersey Board of Public Utilities (NJBPU) and the Virginia State Corporation Commission (VSCC); (iii) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (the HSR Act); and (iv) other customary closing conditions, including (a) the accuracy of each party's representations and warranties (subject to customary materiality qualifiers) and (b) each party's compliance with its obligations and covenants contained in the Merger Agreement (including covenants that may limit, restrict or prohibit PHI and its subsidiaries from taking specified actions during the period between the date of the Merger Agreement and the closing of the Merger or the termination of the Merger Agreement). In addition, the obligations of Exelon and Merger Sub to consummate the Merger are subject to the required regulatory approvals not imposing terms, conditions, obligations or commitments, individually or in the aggregate, that constitute a burdensome condition (as defined in the Merger Agreement). For additional discussion, see Note (7), "Regulatory Matters – Merger Approval Proceedings."

On September 23, 2014, the stockholders of PHI approved the Merger, on October 7, 2014, the VSCC approved the Merger, and on November 20, 2014, FERC approved the Merger. In addition, the transfer of control of certain communications licenses held by certain of PHI's subsidiaries has been approved by the FCC. The NJBPU approved the Merger on February 11, 2015, and on October 15, 2015, voted to extend the effectiveness of its approval until June 30, 2016. The DPSC approved the Merger on May 19, 2015.

On December 22, 2014, the waiting period under the HSR Act expired. Although the Department of Justice (DOJ) allowed the waiting period under the HSR Act to expire without taking any action with respect to the Merger, the DOJ has not advised PHI that it has concluded its investigation. The expiration of the HSR Act waiting period allows for the closing of the Merger at any time on or before December 21, 2015. If the Merger is not completed by that date the parties will be required to refile the required Notification and Report Forms with the DOJ and Federal Trade Commission (FTC), which will restart the 30-day waiting period required by the HSR Act, during which time the Merger may not be consummated, unless these agencies authorize the early termination of the waiting period. PHI and Exelon currently anticipate that they will refile with the DOJ and FTC in November 2015.

On May 15, 2015, the MPSC approved the Merger, with conditions, including conditions that modify and supplement those originally proposed. On May 18, 2015, PHI and Exelon announced that they had committed to fulfill the modified, more stringent conditions and package of customer benefits imposed by the MPSC. Multiple parties have filed petitions for judicial review of the MPSC order by the Circuit Court of Queen Anne’s County, Maryland, seeking to appeal the MPSC order. PHI is vigorously contesting these appeals. The MPSC order remains in effect during the appeals process. At this time, PHI is unable to predict the outcome of the proceeding.

On August 25, 2015, the DCPSC announced at a public meeting that it had denied the merger application, and on August 27, 2015, the DCPSC issued its written order related to the Merger. On September 28, 2015, Exelon, PHI and Pepco, and certain of their respective affiliates, filed an application for reconsideration with the DCPSC requesting reconsideration of the DCPSC order related to the Merger.

On October 6, 2015, Exelon, PHI and Pepco, and certain of their respective affiliates, entered into a Nonunanimous Full Settlement Agreement and Stipulation (the DC Settlement Agreement) with the District of Columbia Government, the Office of the People’s Counsel and other parties, which DC Settlement Agreement contains commitments from Exelon and PHI above those contained in their original merger application.

Also on October 6, 2015, PHI, Exelon and Merger Sub entered into a Letter Agreement (the Letter Agreement), setting forth the terms and conditions under which the parties will file with the DCPSC (a) a Motion of Joint Applicants to Reopen the Record in Formal Case No. 1119 to Allow for Consideration of the DC Settlement Agreement (the Motion to Reopen), or (b) if the Motion to Reopen is not granted, a new merger application, requesting approval of the Merger on the terms and commitments agreed to in the DC Settlement Agreement. Pursuant to the Letter Agreement, PHI and Exelon each agrees, among other things, that neither party will exercise the termination rights each may have under the Merger Agreement on or after October 29, 2015, unless: (i) the DCPSC does not, within 45 days following the date on which the DC Settlement Agreement is filed with the DCPSC (the Settlement Filing Date), set a procedural schedule which allows for a final order for approval of the Merger within 150 days after the Settlement Filing Date, (ii) the DCPSC sets a schedule for action which does not allow for a final order for approval of the Merger within 150 days after the Settlement Filing Date, (iii) the DCPSC fails to issue a final order approving the Merger and the DC Settlement Agreement as filed without condition or modification within 150 days after the Settlement Filing Date, (iv) the DCPSC issues a final order denying approval of the Merger or the DC Settlement Agreement or adds conditions or makes modifications to the DC Settlement Agreement, (v) the DC Settlement Agreement is terminated for any reason, or (vi) on or after the date that is 151 days after the Settlement Filing Date a condition to closing of the Merger has not been satisfied or waived (other than those conditions that by their nature are to be satisfied at the closing). The Letter Agreement also provides that, subject to certain conditions, Exelon may, following receipt of all regulatory approvals consistent with the DC Settlement Agreement, delay closing of the Merger for up to 30 days to engage in capital markets transactions to raise additional funds required to consummate the Merger.

On October 6, 2015, following execution of the DC Settlement Agreement and the Letter Agreement, Exelon, PHI and Pepco, and certain of their respective affiliates, filed with the DCPSC the Motion to Reopen requesting consideration of the DC Settlement Agreement and approval of the Merger on such terms and conditions set forth in the DC Settlement Agreement, without condition or modification, and to stay further proceedings on the application for reconsideration filed by the parties on September 28, 2015 and suspend the time period for reconsideration pending the DCPSC’s consideration of the DC Settlement 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, the distribution and supply of 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 (SOS) in Delaware, the District of Columbia and Maryland, and Basic Generation Service in New Jersey. These supply service obligations are referred to generally as Default Electricity Supply.

Pepco Energy Services

Pepco Energy Services is engaged in the following businesses:

- Energy savings performance contracting: designing, constructing and operating energy efficiency projects and distributed generation equipment, including combined heat and power plants, principally for federal, state and local government customers;
- Underground transmission and distribution: providing underground transmission and distribution construction and maintenance services for electric utilities in North America; and
- Thermal: providing steam and chilled water under long-term contracts through systems owned and operated by Pepco Energy Services, primarily to hotels and casinos in Atlantic City, New Jersey.

During 2012, Pepco Energy Services deactivated its Buzzard Point and Benning Road oil-fired generation facilities. Pepco Energy Services completed demolition of the Benning Road generation facility in July 2015 and recognized the scrap metal salvage value of the facility as a reduction in its demolition expenses over the life of the project.

Corporate and Other

Corporate and Other includes the remaining operations of the former Other Non-Regulated segment, certain parent company transactions (including interest expense on parent company debt and incremental external Merger-related costs) and inter-company eliminations.

(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, 2014. 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, 2015, in accordance with GAAP. The year-end December 31, 2014 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, 2015 may not be indicative of PHI's results that will be realized for the full year ending December 31, 2015.

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, the calculation of 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 adequacy of the allowance for uncollectible accounts, 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 loss contingency liabilities for general litigation and auto and other liability claims, accrual of interest related to income taxes, 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.

Storm Restoration Costs

On June 23, 2015, the service territories of DPL and ACE were affected by a severe storm with damaging winds and heavy rains. This storm resulted in widespread customer outages in each of the service territories and caused damage to the electric transmission and distribution systems of each utility. Storm restoration activity commenced immediately following the storm and continued into July 2015, with the majority of the incremental storm restoration costs occurring in the second quarter of 2015.

Total incremental storm restoration costs incurred by DPL and ACE for the storm through September 30, 2015 were $39 million, with $15 million incurred for repair work and $24 million incurred as capital expenditures. Costs incurred for repair work of $13 million were deferred as regulatory assets to reflect the probable recovery of these costs in Maryland and New Jersey, and $2 million was charged to Other operation and maintenance expense. As of September 30, 2015, the total incremental storm restoration costs included $10 million of estimated costs for unbilled restoration services provided by certain outside contractors. Actual costs for these services may vary from the estimates. DPL and ACE intend to pursue recovery of these incremental storm restoration costs in their respective jurisdictions in their next electric distribution base rate cases.

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. See Note (16), "Variable Interest Entities," for additional information.

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. PHI 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 (that is, a greater than 50% chance) reduce the estimated 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 significantly below book value, an adverse regulatory action, or an impairment of long-lived assets in the reporting unit. PHI performed its most recent annual impairment test as of November 1, 2014, and its goodwill was not impaired as described in Note (6), "Goodwill."

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in Pepco Holdings' gross revenues were $85 million for each of the three months ended September 30, 2015 and 2014, and $249 million and $246 million for the nine months ended September 30, 2015 and 2014, respectively.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Discontinued Operations (ASC 205)

In April 2014, the FASB issued new guidance on the reporting of discontinued operations that is effective for dispositions that occur after January 1, 2015. In order for dispositions to be presented as discontinued operations, the dispositions must represent a strategic shift that will have a major effect on an entity's operations and financial results. Adoption of this guidance during the first quarter of 2015 did not have an impact on PHI's consolidated financial statements.

Business Combinations (ASC 805)

In November 2014, the FASB issued new recognition and disclosure requirements related to pushdown accounting. The new recognition requirements grant an acquired entity (or its subsidiaries) the option to elect whether and when a new accounting and reporting basis (pushdown accounting) will be applied when an acquirer obtains control of the acquired entity. This election may be made by the acquired entity (or its subsidiaries) for future change-in-control events or for its most recent change-in-control event, and the acquired entity will be required to determine whether pushdown accounting will be applied in the reporting period in which the change-in-control event occurs or in a subsequent reporting period.

The new required disclosures include information that enables financial statement users to evaluate the effects of pushdown accounting. Disclosures are required to be made in the period in which pushdown accounting is applied and are expected to include both qualitative and quantitative information.

The new recognition and disclosure requirements became effective on a prospective basis on November 18, 2014. PHI currently anticipates it may be affected by the new guidance if its Merger with Exelon is consummated.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Revenue from Contracts with Customers (ASC 606)

In May 2014, the FASB issued new recognition and disclosure requirements for revenue from contracts with customers, which supersedes the existing revenue recognition guidance. The new recognition requirements focus on when the customer obtains control of the goods or services, rather than the current risks and rewards model of recognition. The core principle of the new standard is that an entity will recognize revenue when it transfers goods or services to its customers in an amount that reflects the consideration an entity expects to be entitled to for those goods or services. The new disclosure requirements will include information intended to communicate the nature, amount, timing and any uncertainty of revenue and cash flows from applicable contracts, including any significant judgments and changes in judgments and assets recognized from the costs to obtain or fulfill a contract. Entities will generally be required to make more estimates and use more judgment under the new standard.

The new requirements will be effective for PHI beginning January 1, 2018, and may be implemented either retrospectively for all periods presented, or as a cumulative-effect adjustment as of January 1, 2018. Early adoption is permitted, but not before January 1, 2017. PHI is currently evaluating the potential impact of this new guidance on its consolidated financial statements and which implementation approach to select.

Presentation of Debt Issuance Costs (ASC 835)

In April 2015, the FASB issued new guidance for the presentation of debt issuance costs on the balance sheet. Debt issuance costs are currently required to be presented on the balance sheet as assets. However, under the new requirements, these debt issuance costs will be offset against the debt to which the costs relate. The new requirements will be effective for PHI beginning January 1, 2016, and are required to be implemented on a retrospective basis for all periods presented. Early adoption is permitted. PHI is currently evaluating the potential impact of this new guidance on its consolidated financial statements, but the impact is not expected to be material.

Fair Value Measurement (ASC 820)

In May 2015, the FASB issued new disclosure requirements for investment fair values. Under the new requirements, investment fair values based on net asset value per share will continue to be disclosed, however, the investment fair values will no longer be included within the fair value tables and a level will not be assigned to those investment fair values. The new requirements are effective for PHI beginning January 1, 2016, and are required to be implemented on a retrospective basis for all periods presented. Early adoption is permitted. PHI is currently evaluating the potential impact of this new guidance on its consolidated financial statements.

Business Combination (ASC 805)

In September 2015, the FASB issued new guidance on adjustments to provisional amounts recognized in a business combination, which are currently recognized on a retrospective basis. Under the new requirements, adjustments will be recognized in the reporting period in which the adjustments are determined. The effects of changes in depreciation, amortization, or other income arising from changes to the provisional amounts, if any, are included in earnings of the reporting period in which the adjustments to the provisional amounts are determined. An entity is also required to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The new requirements will be effective for PHI beginning January 1, 2016, and are required to be implemented on a prospective basis. Early adoption is permitted. PHI currently anticipates it may be affected by the new guidance if its Merger with Exelon is consummated.

(5) SEGMENT INFORMATION

Pepco Holdings' management has identified its operating segments at September 30, 2015 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 the remaining operations of the former Other Non-Regulated segment, unallocated Pepco Holdings' (parent company) capital costs, such as financing costs, and inter-company eliminations.

Segment financial information for the three and nine months ended September 30, 2015 and 2014 are as follows:

	Three Months Ended September 30, 2015			
	Power Delivery	Pepco Energy Services	Corporate and Other (a)	PHI Consolidated
	(millions of dollars)			
Operating Revenue	$ 1,316	$ 47	$ (1)	$ 1,362
Operating Expenses (b)	1,131	49	(1)	1,179
Operating Income (Loss)	185	(2)	—	183
Interest Expense	59	—	12	71
Other Income	11	—	17 (c)	28
Income Tax Expense (Benefit)	49	(2)	2	49
Net Income	88	—	3	91
Total Assets	14,330	218	2,009	16,557
Construction Expenditures	$ 286	$ —	$ 7	$ 293

(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 $(1) million for Operating Revenue, $1 million for Operating Expenses and $(1) million for Interest and Dividend Income.

(b) Includes depreciation and amortization expense of $178 million, consisting of $165 million for Power Delivery, $1 million for Pepco Energy Services and $12 million for Corporate and Other.

(c) Includes $15 million ($10 million after-tax) increase in fair value of preferred stock derivative.

	Three Months Ended September 30, 2014			
	Power Delivery	Pepco Energy Services	Corporate and Other (a)	PHI Consolidated
	(millions of dollars)			
Operating Revenue	$ 1,242	$ 73	$ (2)	$ 1,313
Operating Expenses (b)	1,021	126 (c)	—	1,147
Operating Income (Loss)	221	(53)	(2)	166
Interest Expense	58	1	9	68
Other Income	14	1	—	15
Income Tax Expense (Benefit)	65	(26)	(5)	34
Net Income (Loss)	112	(27)	(6)	79
Total Assets	13,697	255	1,346	15,298
Construction Expenditures	$ 272	$ 1	$ 20	$ 293

(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 Expense and $(2) million for Interest Income.

(b) Includes depreciation and amortization expense of $145 million, consisting of $135 million for Power Delivery, $2 million for Pepco Energy Services and $8 million for Corporate and Other.

(c) Includes an impairment loss of $53 million ($32 million after-tax) at Pepco Energy Services associated with its combined heat and power thermal generating plant and operation assets in Atlantic City.

	Nine Months Ended September 30, 2015			
	Power Delivery	Pepco Energy Services	Corporate and Other (a)	PHI Consolidated
	(millions of dollars)			
Operating Revenue	$ 3,707	$ 170	$ (4)	$ 3,873
Operating Expenses (b)	3,238	172	(1)	3,409
Operating Income (Loss)	469	(2)	(3)	464
Interest Expense	177	—	33	210
Other Income	32	—	17 (c)	49
Income Tax Expense (Benefit)	113	(7)	—	106
Net Income (Loss)	211	5	(19)	197
Total Assets	14,330	218	2,009	16,557
Construction Expenditures	$ 832	$ 2	$ 21	$ 855

(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 $(4) million for Operating Revenue, $(4) million for Operating Expenses, $(2) million for Interest Expense and $(5) million for Interest and Dividend Income.
(b) Includes depreciation and amortization expense of $494 million, consisting of $459 million for Power Delivery, $2 million for Pepco Energy Services and $33 million for Corporate and Other.
(c) Includes $15 million ($10 million after-tax) increase in fair value of preferred stock derivative.

	Nine Months Ended September 30, 2014			
	Power Delivery	Pepco Energy Services	Corporate and Other (a)	PHI Consolidated
	(millions of dollars)			
Operating Revenue	$ 3,554	$ 212	$ (6)	$ 3,760
Operating Expenses (b)	3,005	263 (c)	2	3,270
Operating Income (Loss)	549	(51)	(8)	490
Interest Expense	169	1	30	200
Other Income	39	2	1	42
Income Tax Expense (Benefit)	157	(25)	(7)	125
Net Income (Loss)	262	(25)	(30)	207
Total Assets	13,697	255	1,346	15,298
Construction Expenditures	$ 789	$ 2	$ 55	$ 846

(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 $(6) million for Operating Revenue, $(5) million for Operating Expenses, $(2) million for Interest Expense and $(3) million for Interest Income.
(b) Includes depreciation and amortization expense of $410 million, consisting of $381 million for Power Delivery, $6 million for Pepco Energy Services and $23 million for Corporate and Other.
(c) Includes an impairment loss of $53 million ($32 million after-tax) at Pepco Energy Services associated with its combined heat and power thermal generating plant and operation assets in Atlantic City.

(6) GOODWILL

PHI's goodwill balance was $1,406 million and $1,407 million as of September 30, 2015 and December 31, 2014, respectively. Substantially all of PHI's goodwill balance was generated by Pepco's acquisition of Conectiv (now known as Conectiv, LLC, and the parent of DPL and ACE, and referred to herein as 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, 2014 indicated that goodwill was not impaired. For the nine months ended September 30, 2015, PHI concluded that there were no events or circumstances requiring it to perform an interim goodwill impairment test. PHI will perform its next annual impairment test as of November 1, 2015.

(7) REGULATORY MATTERS

Rate Proceedings

As further described in Note (1), "Organization," on April 29, 2014, PHI entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, PHI and its subsidiaries may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than pursuing the conclusion of certain proceedings, as described below. To date, PHI has not requested such consent from Exelon and has not filed any new distribution base rate cases since entering into the Merger Agreement.

Bill Stabilization Adjustment

Each of PHI's utility subsidiaries proposed in each of its respective jurisdictions the adoption of a mechanism to decouple retail distribution revenue from the amount of power delivered to retail customers. A decoupling mechanism, the 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. None of the other jurisdictions have to date adopted decoupling proposals.

Delaware

Electric Distribution Base Rates

In March 2013, DPL submitted an application with the DPSC to increase its electric distribution base rates. The application sought approval of an annual rate increase of approximately $42 million (adjusted by DPL to approximately $39 million on September 20, 2013), based on a requested return on equity (ROE) of 10.25%. The requested rate increase sought to recover expenses associated with DPL's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. In August 2014, the DPSC issued a final order in this proceeding providing for an annual increase in DPL's electric distribution base rates of approximately $15.1 million, based on an ROE of 9.70%. The new rates became effective on May 1, 2014.

In September 2014, DPL filed an appeal with the Delaware Superior Court of the DPSC's August 2014 order in this proceeding, seeking the court's review of the DPSC's decision relating to the recovery of costs associated with one component of employee compensation, certain retirement benefits and credit facility expenses. The Division of the Public Advocate filed a cross-appeal in September 2014, pertaining to the treatment of a prepaid pension expense and other postretirement benefit obligations in base rates. Under the settlement agreement related to the Merger described below in "Merger Approval Proceedings – Delaware," the parties agreed to suspend the appeal and, if the Merger is completed, to the withdrawal of the appeal and the cross-appeal with prejudice.

Forward Looking Rate Plan

In October 2013, DPL filed a multi-year rate plan, referred to as the Forward Looking Rate Plan (FLRP). As proposed, the FLRP would provide for annual electric distribution base rate increases over a four-year period in the aggregate amount of approximately $56 million. The FLRP as proposed provides the opportunity to achieve estimated earned ROEs of 7.41% and 8.80% in years one and two, respectively, and 9.75% in both years three and four of the plan.

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

In October 2013, the DPSC opened a docket for the purpose of reviewing the details of the FLRP, but stated that it would not address the FLRP until the electric distribution base rate case discussed above was concluded. Although the rate case has been concluded, a schedule for the FLRP docket has not yet been established.

Under the Merger Agreement, DPL is permitted to pursue this matter; however, under the settlement agreement related to the Merger described below in "Merger Approval Proceedings – Delaware," DPL agreed to withdraw the FLRP if the Merger is completed, without prejudice to the right to make future filings with the DPSC proposing alternative regulatory methodologies that could include, but are not limited to, a multi-year rate plan.

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. In August 2014, DPL made its 2014 GCR filing in which it proposed a GCR decrease of approximately 7.4%. In September 2014, the DPSC issued an order authorizing DPL to place the new rates into effect on November 1, 2014, subject to refund and pending final DPSC approval. On August 4, 2015, the DPSC issued an order approving the rates as filed.

On August 27, 2015, DPL made its 2015 GCR filing. The rates proposed in the 2015 GCR filing would result in a GCR decrease of approximately 26%, primarily reflecting lower natural gas prices. On September 22, 2015, the DPSC issued an order allowing DPL to place the new rates into effect on November 1, 2015, subject to refund and pending final DPSC approval.

Under the Merger Agreement, DPL is permitted to continue to file its required annual GCR cases in Delaware.

<u>Maryland</u>

Pepco Electric Distribution Base Rates

<u>2011 Base Rate Proceeding</u>

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 adjusted by Pepco to approximately $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%. Among other things, the order also authorized Pepco to recover the actual cost of advanced metering infrastructure (AMI) meters installed during the 2011 test year, stating 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 rates became effective on July 20, 2012. The Maryland Office of People's Counsel 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.

<u>2012 Base Rate Proceeding – Phase I</u>

In November 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%. In July 2013, the MPSC issued an order in this proceeding approving an annual rate increase of approximately $27.9 million, based on an ROE of 9.36%. 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 carrying charge is deferred, but only until such cost effectiveness has been demonstrated and such costs are included in rates. However, MPSC's July 2012 order issued in connection with Pepco's 2011 base rate proceeding, which allowed Pepco to recover the costs of meters installed during the 2011 test year for that case, remains in effect.

The July 2013 order also approved a Grid Resiliency Charge, which went into effect on January 1, 2014, 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, before implementing the surcharge, Pepco (i) provides additional information to the MPSC related to performance objectives, milestones and costs, and (ii) 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 rejected certain other cost recovery mechanisms, including Pepco's proposed reliability performance-based mechanism. The new rates were effective on July 12, 2013.

In July 2013, Pepco filed a notice of appeal of the July 2013 order in the Circuit Court for Baltimore City. Other parties also filed notices of appeal, which were consolidated with Pepco's appeal. In its appeal, Pepco asserted that the MPSC erred in failing to grant Pepco an adequate ROE, denying a number of other cost recovery mechanisms and limiting Pepco's test year data to no more than four months of forecasted data in future rate cases. The other parties primarily asserted that the MPSC erred or acted arbitrarily and capriciously in allowing the recovery of certain costs by Pepco, in approving the Grid Resiliency Charge, and in refusing to reduce Pepco's rate base by known and measurable accumulated depreciation. In November 2014, the Circuit Court issued an order reversing the MPSC's decision on Pepco's ROE and directing the MPSC to make more specific findings regarding the impact of improved service reliability and the BSA in calculating Pepco's ROE. On all other issues that were the subject of an appeal, the Circuit Court affirmed the MPSC's July 2013 order. Other parties to this proceeding have filed notices of appeal of the Circuit Court's decision to the Court of Special Appeals, where the case remains pending. Pepco has elected not to appeal the decision of the Circuit Court.

2013 Base Rate Proceeding – Phase I

In December 2013, 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 $43.3 million (adjusted by Pepco to approximately $37.4 million on April 15, 2014), based on a requested ROE of 10.25%. The requested rate increase sought to recover expenses associated with Pepco's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. In July 2014, the MPSC issued an order approving an annual rate increase of approximately $8.75 million, based on an ROE of 9.62%. The new rates became effective on July 4, 2014. In July 2014, Pepco filed a petition for rehearing seeking reconsideration of the recovery of certain expenses, which the MPSC denied by its order issued in November 2014 (described below). In December 2014, Pepco filed a petition for judicial review of this MPSC order with the Circuit Court for Baltimore City. On August 7, 2015, the Circuit Court for Baltimore City affirmed the MPSC's decision and denied Pepco's appeal. Pepco has elected not to appeal the decision of the Circuit Court.

2012 and 2013 Base Rate Proceedings – Phase II

In August 2014, the MPSC issued an order establishing a Phase II proceeding in the 2012 base rate case described above (the 2012 Phase II proceeding) to address the tax implications of Pepco's net operating loss carryforward (NOLC), which had impacted certain of Pepco's rate adjustments in the 2012 base rate proceeding. Pepco filed a motion to dismiss the 2012 Phase II proceeding, asserting that the MPSC no longer has jurisdiction over the 2012 base rate case due to appeals having been filed by numerous parties. In September 2014, the MPSC issued an order staying the 2012 Phase II proceeding until further notice. In a similar Phase II proceeding in the 2013 base rate case described above, the MPSC issued an order in November 2014 upholding Pepco's treatment of the NOLC. Although Pepco believes the November 2014 MPSC order should be dispositive of the issues raised in the 2012 Phase II proceeding, the 2012 Phase II proceeding is expected to remain open until all appeals of the 2012 base rate proceeding are resolved, whereupon the MPSC will have authority to act on Phase II.

<u>*New Jersey*</u>

Update and Reconciliation of Certain Under-Recovered Balances

In March 2015, ACE submitted its 2015 annual 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 non-utility generators (NUGs), and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and for ACE's uncollected accounts. As filed, the net impact of the proposed changes would have been an annual rate increase of approximately $52.0 million (revised to an increase of approximately $33.9 million on April 17, 2015, based upon updates for actual data through March 31, 2015). On May 19, 2015, the NJBPU approved a stipulation of settlement entered into by the parties providing for an overall annual rate increase of $33.9 million. The rate increase, which went into effect on June 1, 2015, was placed into effect provisionally, subject to a review by the NJBPU and the Division of Rate Counsel of the final underlying costs for reasonableness and prudence. On September 11, 2015, the NJBPU approved a stipulation of settlement in this proceeding, which made final the provisional rates that were placed into effect on June 1, 2015, with an adjustment that decreased the rate applicable to the residential class by $1.3 million. This rate increase of approximately $32.6 million will have no effect on ACE's operating income, since these revenues provide for recovery of deferred costs under an approved deferral mechanism.

Service Extension Contributions Refund Order

In July 2013, in compliance with a 2012 Superior Court of New Jersey Appellate Division (Appellate Division) court decision, the NJBPU released an order requiring utilities to issue refunds to persons or entities that paid non-refundable contributions for utility 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. Although ACE estimates that 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. Since the July 2013 order was released, ACE has paid less than $1 million in refund claims, the validity of each of which is investigated by ACE prior to making any such refunds. In September 2014, the NJBPU commenced a rulemaking proceeding to further implement the directives of the Appellate Division decision and, in December 2014, published a rule proposal for comment. The changes proposed by the NJBPU remove provisions distinguishing between growth areas and not-for-growth areas and provide formulae for allocating extension costs. ACE has been an active participant in the rulemaking proceeding. Final rules have not yet been promulgated by the NJBPU. At this time, ACE does not expect the amount it is ultimately required to refund will have a material effect on its consolidated financial condition, results of operations or cash flows, as the amount refunded will generally increase the value of ACE's property, plant and equipment and may ultimately be recovered through depreciation expense and cost of service in future electric distribution base rate cases.

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 NJBPU's current policy, 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. This policy has negatively impacted ACE's electric distribution base rate case outcomes and ACE's position is that the CTA should be eliminated. In an order issued in October 2014, the NJBPU determined that it is appropriate for affected consolidated groups to continue to include a CTA in New Jersey base rate filings, but that the CTA calculation will be modified to limit the look-back period for the calculation to five years, exclude transmission assets from the calculation, and allocate 25 percent of the final CTA amount as a reduction to the distribution revenue requirement. ACE anticipates that this revised methodology will significantly reduce the negative effects of the CTA in future base rate cases. In November 2014, the New Jersey Division of Rate Counsel filed an appeal of the NJBPU's CTA order in the Appellate Division. No stay of the October 2014 CTA order was requested in connection with the appeal. As such, barring an adverse finding by the Appellate Division, the order is in effect. The appeal remains pending.

FERC Transmission ROE Challenges

In February 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Municipal Electric Corporation, Inc. (DEMEC), filed a joint complaint at FERC against Pepco, DPL and ACE, as well as Baltimore Gas and Electric Company (BGE). The complainants challenged the base ROE and certain protocols regarding the formula rate process associated with the transmission service that the 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. The 10.8% base ROE for facilities placed into service prior to 2006 receives 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 this complaint. In August 2014, FERC issued an order setting the matters in this proceeding for hearing, but holding the hearing in abeyance pending settlement discussions. The order also (i) directed that the evidence and analysis presented concerning ROE be guided by the new ROE methodology adopted by FERC in another proceeding (discussed below), and (ii) set a 15-month refund period that commenced on February 27, 2013, should a refund result from this proceeding. After settlement discussions among the parties in this matter reached an impasse, the settlement judge, in November 2014, issued an order terminating the settlement discussions and referring the matter to a presiding administrative law judge.

In June 2014, FERC issued an order in a proceeding in which the PHI utilities were not involved, in which it adopted a new ROE methodology for electric utilities. This new methodology replaces the existing one-step discounted cash flow analysis (which incorporates only short-term growth rates) traditionally used to derive ROE for electric utilities with the two-step discounted cash flow analysis (which incorporates both short-term and long-term measures of growth) used for natural gas and oil pipelines. As a result of the August 2014 FERC order discussed in the preceding paragraph, Pepco, DPL and ACE applied an estimated ROE based on the two-step methodology announced by FERC for the 15-month period over which each of their transmission revenues would be subject to refund as a result of the challenge, and recorded estimated reserves for the entire 15-month refund period in the second quarter of 2014.

On December 8, 2014, the parties that filed the February 2013 complaint filed a second complaint against Pepco, DPL, ACE, as well as BGE, regarding the base transmission ROE, seeking a reduction from 10.8% to 8.8%. By order issued on February 9, 2015, FERC established a hearing on the second complaint and established a second 15-month refund period that commenced on December 8, 2014. Consistent with the prior challenge, Pepco, DPL and ACE applied an estimated ROE based on the two-step methodology described above, and in the fourth quarter of 2014 and in the first, second and third quarters of 2015 established reserves for the estimated refund based on the effective date of the second refund period of December 8, 2014. On February 20, 2015, the chief judge issued an order consolidating the two complaint proceedings and established an initial decision issuance deadline of February 29, 2016. On March 2, 2015, the presiding administrative law judge issued an order establishing a procedural schedule for the consolidated proceedings that provides for the hearing to commence on October 20, 2015.

Also during the third quarter of 2015, PHI further evaluated the reserves established for each of the two refund periods and, based on an updated assessment of market conditions, developments in other cases before FERC, litigation risk and other factors, increased its reserves to reflect management's best estimate of the refund that is expected to result from these consolidated proceedings. As of September 30, 2015, PHI's reserves for both of the refund periods totaled $28 million. A settlement entered into by the parties regarding the protocols (but not the ROE) raised in the February 2013 complaint was submitted to FERC on July 31, 2015 and is awaiting FERC approval.

To the extent that the final ROE established in these consolidated proceedings is lower than the ROE used to record the estimated reserves with respect to the February 2013 and the December 2014 complaints, each ten basis point reduction in the ROE would result in an increase in required reserves and a reduction of PHI's operating income of $3.0 million.

MPSC New Generation Contract Requirement

In April 2012, the MPSC issued an order that requires Maryland electric distribution companies (EDCs) Pepco, DPL and BGE (collectively, the Contract EDCs) to negotiate and enter into a contract with the winning bidder of a competitive bidding process to build one new power plant in the range of 650 to 700 megawatts (MWs) beginning in 2015, in amounts proportional to their relative SOS loads. Under the terms of the order, the winning bidder was to construct a 661 MW natural gas-fired combined cycle generation plant in Waldorf, Maryland, with an originally expected commercial operation date of June 1, 2015 (which is now deferred pending the outcome of the proceedings discussed below), and each of the Contract EDCs was to recover its costs associated with the contract through surcharges on its respective SOS customers.

In response to a complaint filed by a group of generating companies in the PJM Interconnection, LLC region, in September 2013, the U.S. District Court for the District of Maryland (the Federal District Court) 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, in October 2013, in response to appeals filed by the Contract EDCs and other parties, the Maryland Circuit Court for Baltimore City (the Maryland Circuit Court) upheld the MPSC's orders requiring the Contract EDCs to enter into the contracts.

In October 2013, the Federal District Court issued an order ruling that the contracts are illegal and unenforceable. The Contract EDCs, the Maryland Office of People's Counsel and one generating company have appealed the Maryland Circuit Court's decision to the Maryland Court of Special Appeals. In addition, in November 2013 both the winning bidder and the MPSC appealed the Federal District Court decision to the U.S. Court of Appeals for the Fourth Circuit, which affirmed the decision. In November 2014, the winning bidder and the MPSC each petitioned the U.S. Supreme Court to consider hearing an appeal of the Fourth Circuit decision and, on October 19, 2015, the U.S. Supreme Court agreed to review that decision.

Assuming the contracts, as currently written, become effective following the satisfaction of all relevant conditions, including the completion of the proceedings discussed above, PHI continues to believe that Pepco and DPL may be required to record their proportional share of the contracts as derivative instruments at fair value and record related regulatory assets of approximately the same amount because Pepco and DPL would be entitled to recover any payments under the contracts from SOS customers. 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.

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. ACE entered into the SOCAs under protest, as did the other EDCs in New Jersey, arguing that the EDCs were denied due process and that the SOCAs violated certain of the requirements of the New Jersey law under which the SOCAs were established (the NJ SOCA Law). In October 2013, in light of the decision of the U.S. District Court for the District of New Jersey described below, the state appeals of the NJBPU implementation orders filed by the EDCs and generators were dismissed 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. In October 2013, the Federal district court ruled that the NJ SOCA Law is preempted by the Federal Power Act (FPA) and violates the Supremacy Clause, and is therefore null and void. In October 2013, the Federal district court issued an order ruling that the SOCAs are void, invalid and unenforceable, which order was affirmed by the U.S. Court of Appeals for the Third Circuit in September 2014. In November 2014 and December 2014, respectively, one of the generation companies and the NJBPU petitioned the U.S. Supreme Court to consider hearing an appeal of the Third Circuit decision. Although the U.S. Supreme Court agreed to review the Fourth Circuit decision discussed above under “MPSC New Generation Contract Requirement,” the petitions currently remain pending in the Third Circuit.

ACE terminated one of the three SOCAs effective July 1, 2013 due to the occurrence of an event of default on the part of the generation company counterparty. ACE terminated the remaining two SOCAs effective November 19, 2013, in response to the October 2013 Federal district court decision.

In response to the October 2013 Federal district court order, ACE, in the fourth quarter of 2013, derecognized both the derivative assets (liabilities) for the estimated fair value of the SOCAs and the related regulatory liabilities (assets) that it had established with respect to the SOCAs.

District of Columbia Power Line Undergrounding Initiative

In May 2014, the Council of the District of Columbia enacted the Electric Company Infrastructure Improvement Financing Act of 2014 (the Improvement Financing Act), which provides enabling legislation for the District of Columbia Power Line Undergrounding (DC PLUG) initiative. This $1 billion initiative seeks to selectively place underground some of the District of Columbia’s most outage-prone power lines, which lines and surrounding conduit would be owned and maintained by Pepco.

The Improvement Financing Act provides that: (i) Pepco is to fund approximately $500 million of the estimated cost to complete the DC PLUG initiative, recovering those costs through a surcharge on the electric bills of Pepco District of Columbia customers; (ii) $375 million of the DC PLUG initiative cost is to be financed by the District of Columbia’s issuance of securitized bonds, which bonds will be repaid through a surcharge on the electric bills of Pepco District of Columbia customers that Pepco will collect on behalf of and remit to the District of Columbia; and (iii) the remaining costs up to $125 million are to be covered by the existing capital projects program of the District of Columbia Department of Transportation (DDOT). Pepco will not earn a return on or a return of the cost of the assets funded with the proceeds of the securitized bonds or assets that are constructed by DDOT under its capital projects program, but ownership and responsibility for the operation and maintenance of such assets will be transferred to Pepco for a nominal amount.

In June 2014, Pepco and DDOT filed a Triennial Plan related to the construction of selected underground feeders in the District of Columbia and recovery of Pepco’s investment through a volumetric surcharge (the Triennial Plan), all in accordance with the Improvement Financing Act. In August 2014, Pepco filed an application for the issuance of a financing order to provide for the issuance of the District’s bonds and a volumetric surcharge for the District of Columbia to recover the costs associated with the bond issuance (the DDOT surcharge).

In November 2014, the DCPSC issued an order approving the Triennial Plan, including Pepco’s volumetric surcharge, and issued the financing order, including approval of the DDOT surcharge. Together these orders permit (i) Pepco and DDOT to commence proposed construction under the Triennial Plan; (ii) the District of Columbia to issue the necessary bonds to fund the District of Columbia’s portion of the DC PLUG initiative; and (iii) the establishment of the customer surcharges contemplated by the Improvement Financing Act. In December 2014, a party to the proceeding sought reconsideration from the DCPSC of both decisions. Final decisions denying both requests for reconsideration were issued by the DCPSC on January 22, 2015 and February 2, 2015, respectively.

In March 2015, a party to the DCPSC proceedings filed with the District of Columbia Court of Appeals a petition for review of the order approving the Triennial Plan and the issuance of the financing order. In August 2015, the DCPSC filed a motion with the District of Columbia Court of Appeals to dismiss or, in the alternative, for summary affirmance, which was denied by the court in September 2015. The District of Columbia Court of Appeals is scheduled to hear the case in November 2015. Separately, in June 2015, an agency of the federal government served by Pepco asserted that the DDOT surcharge constitutes a tax on end users from which the federal government is immune. PHI is currently evaluating the assertion and the resolution of this matter will likely delay implementation of the undergrounding initiative.

Merger Approval Proceedings

Delaware

On June 18, 2014, Exelon, PHI and DPL, and certain of their respective affiliates, filed an application with the DPSC seeking approval of the Merger. Delaware law requires the DPSC to approve the Merger when it determines that the transaction is in accordance with law, for a proper purpose, and is consistent with the public interest. The DPSC must further find that the successor will continue to provide safe and reliable service, will not terminate or impair existing collective bargaining agreements and will engage in good faith bargaining with organized labor. On February 13, 2015, Exelon, DPL, the DPSC staff, the Division of the Public Advocate and certain other parties filed a settlement agreement with the DPSC, which was amended in April 2015. The DPSC approved the amended settlement agreement at its meeting held on May 19, 2015, memorializing this decision by written order issued on June 2, 2015. The specific grounds for the DPSC's approval of the Merger, as well as the specific conditions, will be included in an order to be issued by the DPSC after the Merger closes.

District of Columbia

On June 18, 2014, Exelon, PHI and Pepco, and certain of their respective affiliates, filed an application with the DCPSC seeking approval of the Merger. To approve the Merger, the DCPSC must find that the Merger is in the public interest. In an order issued August 22, 2014, the DCPSC stated that to make the determination of whether the transaction is in the public interest, it will analyze the transaction in the context of seven factors to determine whether the transaction balances the interests of shareholders and investors with ratepayers and the community, whether the benefits to shareholders do or do not come at the expense of the ratepayers, and whether the transaction produces a direct and tangible benefit to ratepayers. The seven factors identified by the DCPSC are the effects of the transaction on: (i) ratepayers, shareholders, the financial health of the utility standing alone and as merged, and the local economy; (ii) utility management and administrative operations; (iii) the public safety and the safety and reliability of services; (iv) risks associated with all of the affiliated non-jurisdictional business operations, including nuclear operations, of the applicants; (v) the DCPSC's ability to regulate the utility effectively following the Merger; (vi) competition in the local retail and wholesale markets that impacts the District and District ratepayers; and (vii) conservation of natural resources and preservation of environmental quality. District of Columbia law does not impose any time limit on the DCPSC's review of the Merger. The DCPSC held evidentiary hearings in March and April of 2015 and the record was closed on May 27, 2015.

On August 25, 2015, the DCPSC announced at a public meeting that it had denied the merger application and Pepco Holdings and Exelon indicated that the parties were evaluating all available options, including requesting a rehearing of the DCPSC's decision. On August 27, 2015, the DCPSC issued its written order related to the Merger. On September 28, 2015, Exelon, PHI and Pepco, and certain of their respective affiliates, filed an application for reconsideration before the DCPSC. Following the DCPSC's decision on reconsideration, Exelon and Pepco Holdings have the option of filing further appeals with the DC Court of Appeals.

On October 6, 2015, Exelon, PHI and Pepco, and certain of their respective affiliates, entered into the DC Settlement Agreement with the District of Columbia Government, the Office of the People's Counsel and other parties. Also on October 6, 2015, Exelon, PHI and Pepco, and certain of their respective affiliates filed with the DCPSC the Motion to Reopen requesting consideration of the DC Settlement Agreement and approval of the Merger on such terms and conditions set forth in the DC Settlement Agreement, without condition or modification, and to stay further proceedings on the application for reconsideration filed by the parties on September 28, 2015, and suspend the time period for reconsideration pending the DCPSC's consideration of the DC Settlement Agreement.

Maryland

On August 19, 2014, Exelon, PHI, Pepco, DPL and certain of their respective affiliates, filed an application with the MPSC seeking approval of the Merger. Maryland law requires the MPSC to approve a merger subject to its review if it finds that the merger is consistent with the public interest, convenience and necessity, including its benefits to and impact on consumers. Evidentiary hearings were held beginning on January 26, 2015. On March 10, 2015, Exelon, PHI, Pepco, DPL and certain of their respective affiliates, filed with the MPSC a settlement agreement entered into with one of the stakeholder groups participating in the MPSC approval proceeding. On March 16, 2015, Exelon, PHI, Pepco, DPL and certain of their respective affiliates, filed with the MPSC a settlement agreement entered into with Montgomery and Prince George's Counties in Maryland, and a number of other parties. On May 15, 2015, the MPSC approved the Merger, with conditions, including conditions that modify and supplement those originally proposed. On May 18, 2015, Pepco Holdings and Exelon announced that they had completed their review of the MPSC's order approving the Merger and have committed to fulfill the modified, more stringent conditions and package of customer benefits imposed by the MPSC.

Multiple parties have filed petitions for judicial review of the MPSC order by the Circuit Court of Queen Anne's County, Maryland, seeking to appeal the MPSC order. In connection with these proceedings, the Maryland Office of People's Counsel and several other parties to the Merger proceedings filed motions in the Circuit Court for Queen Anne's County, Maryland, requesting a stay of the MPSC order. On August 7, 2015, the Circuit Court for Queen Anne's County denied the motions for stay. Exelon and Pepco Holdings are vigorously contesting these appeals of the MPSC order. The MPSC order remains in effect during the appeals process. At this time, PHI is unable to predict the outcome of the proceeding.

New Jersey

On June 18, 2014, Exelon, PHI and ACE, and certain of their respective affiliates, filed a petition with the NJBPU seeking approval of the Merger. To approve the Merger, the NJBPU must find the Merger is in the public interest, and consider the impact of the Merger on (i) competition, (ii) rates of ratepayers affected by the Merger, (iii) ACE's employees, and (iv) the provision of safe and reliable service at just and reasonable rates. On January 14, 2015, PHI, ACE, Exelon, certain of Exelon's affiliates, the Staff of the NJBPU, and the Independent Energy Producers of New Jersey filed a stipulation of settlement (the Stipulation) with the NJBPU in this proceeding. On February 11, 2015, the NJBPU approved the Stipulation and the Merger and on March 6, 2015, the NJBPU issued a written order approving the Stipulation.

The NJBPU order states that the Merger must be closed by November 1, 2015 unless extended by the NJBPU. On October 15, 2015, the NJBPU voted to extend the effectiveness of its Merger approval until June 30, 2016.

Virginia

On June 3, 2014, Exelon, PHI, Pepco and DPL, and certain of their respective affiliates, filed an application with the VSCC seeking approval of the Merger. Virginia law provides that, if the VSCC determines, with or without hearing, that adequate service to the public at just and reasonable rates will not be impaired or jeopardized by granting the application for approval, then the VSCC shall approve a merger with such conditions that the VSCC deems to be appropriate in order to satisfy this standard. On October 7, 2014, the VSCC issued an order approving the Merger.

Federal Energy Regulatory Commission

On May 30, 2014, Exelon, PHI, Pepco, DPL and ACE, and certain of their respective affiliates, submitted to FERC a Joint Application for Authorization of Disposition of Jurisdictional Assets and Merger under Section 203 of the FPA. Under that section, FERC shall approve a merger if it finds that the proposed transaction will be consistent with the public interest. On November 20, 2014, FERC issued an order approving the Merger.

Hart-Scott-Rodino Act

The HSR Act, which is the U.S. federal pre-merger notification statute, and its related rules and regulations provide that acquisition transactions that meet the HSR Act's coverage thresholds may not be completed until a Notification and Report Form has been furnished to the DOJ and the FTC, and that the waiting period required by the HSR Act has been terminated or has expired. Pursuant to the HSR Act requirements, Pepco Holdings and Exelon filed the required Notification and Report Forms with the DOJ and the FTC on August 6, 2014. Following informal discussions with the DOJ, effective as of September 5, 2014, Exelon withdrew its Notification and Report Form and refiled it on September 9, 2014, which restarted the waiting period required by the HSR Act. On October 9, 2014, each of Pepco Holdings and Exelon received a request for additional information and documentary material from the DOJ, which had the effect of extending the DOJ review period until 30 days after each of Pepco Holdings and Exelon certified that it had substantially complied with the request. On November 21, 2014, each of Pepco Holdings and Exelon certified that it had substantially complied with the request. Accordingly, the HSR Act waiting period expired on December 22, 2014. Although the DOJ allowed the waiting period under the HSR Act to expire without taking any action with respect to the Merger, the DOJ has not advised PHI that it has concluded its investigation. The expiration of the HSR Act waiting period allows for the closing of the Merger at any time on or before December 21, 2015. If the Merger is not completed by that date the parties will be required to refile the required Notification and Report Forms with the DOJ and FTC, which will restart the 30 day waiting period required by the HSR Act, during which time the Merger may not be consummated, unless these agencies authorize the early termination of the waiting period. PHI and Exelon currently anticipate that they will refile with the DOJ and FTC in November 2015.

(8) PENSION AND OTHER POSTRETIREMENT BENEFITS

The table below provides the components of net periodic benefit costs recognized by Pepco Holdings for the three months ended September 30, 2015 and 2014:

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014
	(millions of dollars)			
Service cost	$ 15	$ 12	$ 2	$ 1
Interest cost	28	27	6	7
Expected return on plan assets	(35)	(36)	(6)	(6)
Amortization of prior service cost (benefit)	—	1	(3)	(2)
Amortization of net actuarial loss	16	12	2	—
Net periodic benefit cost	$ 24	$ 16	$ 1	$ —

The table below provides the components of net periodic benefit costs recognized by Pepco Holdings for the nine months ended September 30, 2015 and 2014:

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014
	(millions of dollars)			
Service cost	$ 43	$ 33	$ 5	$ 5
Interest cost	82	82	18	20
Expected return on plan assets	(105)	(107)	(17)	(18)
Amortization of prior service cost (benefit)	1	2	(9)	(9)
Amortization of net actuarial loss	49	34	6	2
Net periodic benefit cost	$ 70	$ 44	$ 3	$ —

Pension and Other Postretirement Benefits

Net periodic benefit cost 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. PHI anticipates approximately 36% of annual net periodic pension and other postretirement benefit costs will be capitalized.

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. For the nine months ended September 30, 2015 and 2014, PHI, Pepco, DPL and ACE made no discretionary tax-deductible contributions to the PHI Retirement Plan.

(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, 2013, as permitted under the existing terms of the credit agreement, a request by PHI, Pepco, DPL and ACE to extend the credit facility termination date to August 1, 2018 was approved. All of the terms and conditions as well as pricing remained 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, $200 million, $250 million and $300 million for PHI, Pepco, DPL and ACE, respectively. 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, 2015.

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, 2015 and December 31, 2014, 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 $1,029 million and $875 million, respectively. PHI's utility subsidiaries had combined cash and unused borrowing capacity under the credit facility of $413 million at each of September 30, 2015 and December 31, 2014.

Credit Facility Amendment

On May 20, 2014, PHI, Pepco, DPL and ACE entered into an amendment of and consent with respect to the credit agreement (the Consent). PHI was required to obtain the consent of certain of the lenders under the credit facility in order to permit the consummation of the Merger. Pursuant to the Consent, certain of the lenders consented to the consummation of the Merger and the subsequent conversion of PHI from a Delaware corporation to a Delaware limited liability company, provided that the Merger and subsequent conversion are consummated on or before October 29, 2015. In addition, the Consent amends the definition of "Change in Control" in the credit agreement to mean, following consummation of the Merger, an event or series of events by which Exelon no longer owns, directly or indirectly, 100% of the outstanding shares of voting stock of Pepco Holdings. PHI has requested an extension of the Consent to allow for completion of the Merger by June 30, 2016.

Commercial Paper

PHI, Pepco, DPL and ACE maintain on-going commercial paper programs to address short-term liquidity needs. As of September 30, 2015, the maximum capacity available under these programs was $875 million, $500 million, $500 million and $350 million, respectively, subject to available borrowing capacity under the credit facility.

PHI, Pepco, DPL and ACE had $384 million, $48 million, $66 million and $225 million, respectively, of commercial paper outstanding at September 30, 2015. The weighted average interest rate for commercial paper issued by PHI, Pepco, DPL and ACE during the nine months ended September 30, 2015 was 0.76%, 0.43%, 0.46% and 0.46%, respectively. The weighted average maturity of all commercial paper issued by PHI, Pepco, DPL and ACE during the nine months ended September 30, 2015 was ten, five, three and six days, respectively.

Other Financing Activities

PHI Term Loan Agreement

On July 30, 2015, PHI entered into a $300 million term loan agreement, pursuant to which PHI borrowed $300 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 0.95%. PHI used the net proceeds of the loan under the loan agreement to repay a portion of its outstanding commercial paper, and for general corporate purposes. All indebtedness incurred under the loan agreement is 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 July 28, 2016. Pursuant to the term loan agreement, PHI may consummate the Merger and the subsequent conversion of PHI from a Delaware corporation to a Delaware limited liability company, provided that the Merger and subsequent conversion are consummated on or before October 29, 2015. PHI has requested the consent of the lenders under the term loan to allow for completion of the Merger by June 30, 2016.

Bond Payments

In July 2015, Atlantic City Electric Transition Funding LLC (ACE Funding) made the final principal payment of $1 million on its Series 2002-1 Bonds, Class A-3, and principal payments of $6 million on its Series 2002-1 Bonds, Class A-4 and $3 million on its Series 2003-1 Bonds, Class A-3.

Bond Retirements

In August 2015, ACE retired at maturity, $15 million of its secured medium-term notes series C.

Sale of Receivables

On September 28, 2015, Pepco, as seller, entered into a purchase agreement with a buyer to sell receivables from an energy savings project over a period of time pursuant to a task order. The purchase price to be received by Pepco is $5 million. Pursuant to the purchase agreement, following acceptance of the energy savings project by the buyer, the buyer is entitled to receive the contract payments under the task order payable by the customer over approximately 15 years. The energy savings project will be performed by Pepco Energy Services and is expected to be completed by the end of 2017.

During 2014, Pepco, as seller, entered into a purchase agreement with a buyer to sell receivables from an energy savings project pursuant to a task order entered into under a General Services Administration area-wide agreement. The purchase price received by Pepco was $12 million. The energy savings project was performed by Pepco Energy Services and was completed in 2014. Pursuant to the purchase agreement, following acceptance of the energy savings project by the buyer, the buyer was entitled to receive the contract payments under the task order payable by the buyer over approximately 9 years. The energy savings project was accepted during the first quarter of 2015 and the amount was removed from the Current portion of long-term debt and project funding.

On October 24, 2013, Pepco Energy Services, as seller, entered into a purchase agreement with a buyer to sell receivables from an energy savings project over a period of time pursuant to a task order. The purchase price received by Pepco Energy Services was $7 million. Pursuant to the purchase agreement, following acceptance of the energy savings project by the buyer, the buyer is entitled to receive the contract payments under the task order payable by the customer over approximately 23 years. The energy savings project was accepted during the first quarter of 2015 and the amount was removed from the Current portion of long-term debt and project funding.

Financing Activities Subsequent to September 30, 2015

Bond Payments

In October 2015, ACE Funding made principal payments of $9 million on its Series 2002-1 Bonds, Class A-4 and $3 million on its Series 2003-1 Bonds, Class A-3.

In October 2015, PHI repaid at maturity $250 million of its 2.70% notes due October 1, 2015.

(10) INCOME TAXES

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2015		2014		2015		2014	
	(millions of dollars)							
Income tax at Federal statutory rate	$ 49	35.0%	$ 40	35.0%	$ 106	35.0%	$ 116	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	8	5.7%	6	5.3%	18	5.9%	21	6.3%
Asset removal costs	(3)	(2.1)%	(4)	(3.5)%	(11)	(3.6)%	(9)	(2.7)%
Energy efficiency-related tax deductions	(2)	(1.4)%	(4)	(3.5)%	(6)	(2.0)%	(4)	(1.2)%
Merger-related costs	—	—	—	—	4	1.3%	7	2.1%
Other, net	(3)	(2.2)%	(4)	(3.2)%	(5)	(1.6)%	(6)	(1.9)%
Consolidated income tax expense	$ 49	35.0%	$ 34	30.1%	$ 106	35.0%	$ 125	37.6%

During the three and nine months ended September 30, 2015, PHI recorded a tax benefit of $2 million and $6 million, respectively, related to certain energy efficiency tax deductions associated with Pepco Energy Services' energy savings performance contracting services.

In connection with the proposed Merger (as further described in Note (1), "Organization"), PHI incurred certain merger-related costs, which are not tax-deductible.

Changes to the District of Columbia Tax Law

On February 26, 2015, the District of Columbia Fiscal Year 2015 Budget Support Act of 2014 became law, effective January 1, 2015. The law revised the apportionment methodology for corporate tax and included a phase-down of the corporate tax rate from 9.975% to 8.25% by fiscal year 2019. The change in law required PHI and Pepco to remeasure their net deferred tax liabilities in the first quarter of 2015. This remeasurement resulted in Pepco reducing its deferred tax liabilities by $23 million in the first quarter of 2015 to reflect the initial reduction in the tax rate from 9.975% to 9.4% for 2015. This reduction to the deferred tax liabilities was offset by a corresponding decrease to Pepco's regulatory assets. Further reductions to the corporate tax rate beyond 2015 will depend upon future revenue projections for the District of Columbia.

(11) EQUITY AND EARNINGS PER SHARE

Basic and Diluted Earnings Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(millions of dollars, except per share data)			
Income (Numerator):				
Net income	$ 91	$ 79	$ 197	$ 207
Shares (Denominator) (in millions):				
Weighted average shares outstanding for basic computation:				
Average shares outstanding	254	252	253	251
Adjustment to shares outstanding	—	—	—	—
Weighted Average Shares Outstanding for Computation of Basic Earnings Per Share of Common Stock	254	252	253	251
Net effect of potentially dilutive shares (a)	—	—	1(b)	1(b)
Weighted Average Shares Outstanding for Computation of Diluted Earnings Per Share of Common Stock	254	252	254	252
Basic and Diluted Earnings per Share				
Basic and diluted earnings per share	$ 0.36	$ 0.31	$ 0.78	$ 0.82

(a) There were no options to purchase shares of common stock that were excluded from the calculation of diluted EPS for each of the three and nine months ended September 30, 2015 and 2014.
(b) Includes certain unvested performance-based restricted stock units.

(12) PREFERRED STOCK

In connection with entering into the Merger Agreement (as further described in Note (1), "Organization"), PHI entered into a Subscription Agreement with Exelon, dated April 29, 2014, pursuant to which PHI issued to Exelon 9,000 originally issued shares of Preferred Stock for a purchase price of $90 million on April 30, 2014. In connection with these agreements, Exelon also committed to purchase 1,800 originally issued shares of Preferred Stock for a purchase price of $18 million at the end of each 90-day period following April 29, 2014, up to a maximum of 18,000 shares of Preferred Stock for a maximum aggregate consideration of $180 million. In accordance with the Subscription Agreement, on each of July 29, 2014, October 27, 2014, January 26, 2015, April 27, 2015 and July 24, 2015, an additional 1,800 shares of Preferred Stock were issued by PHI to Exelon for a purchase price of $18 million. If the Merger closes or terminates for any reason, no additional shares of Preferred Stock will be issued pursuant to the Subscription Agreement. The holders of the Preferred Stock will be entitled to receive a cumulative, non-participating cash dividend of 0.1% per annum, payable quarterly, when, as and if declared by PHI's board of directors. The proceeds from the issuance of the Preferred Stock are not subject to restrictions and are intended to serve as a prepayment of any applicable reverse termination fee payable from Exelon to PHI. The Preferred Stock will be redeemable on the terms and in the circumstances set forth in the Merger Agreement and the Subscription Agreement.

If the Merger Agreement is terminated due to a Regulatory Termination, PHI will be able to redeem any issued and outstanding Preferred Stock at par value ($0.01 per share). If the Merger Agreement is terminated for any other reason, PHI will be required to redeem all issued and outstanding Preferred Stock at the purchase price of $10,000 per share, plus any unpaid accrued and accumulated dividends thereupon.

PHI has excluded the Preferred Stock from equity at September 30, 2015 and December 31, 2014, since the Preferred Stock contains conditions for redemption that are not solely within the control of PHI. Management determined that the Preferred Stock contains embedded features requiring separate accounting consideration to reflect the potential value to PHI that any issued and outstanding Preferred Stock could be called and redeemed at a nominal par value upon a Regulatory Termination. The embedded call and redemption features on the shares of the Preferred Stock in the event of a Regulatory Termination are separately accounted for as derivatives. The estimated fair value of the derivatives related to the Preferred Stock at December 31, 2014 was $3 million and has been included in current assets (Prepaid expenses and other) with a corresponding increase in Preferred Stock on the consolidated balance sheet at December 31, 2014. These Preferred Stock derivatives are valued at each reporting date using quantitative and qualitative factors, including management’s assessment of the likelihood of a Regulatory Termination. As of September 30, 2015, the fair value of the remaining derivative related to the Preferred Stock was estimated to be $18 million based on management’s updated assessment. The $15 million increase in the fair value of the derivative has been included in Other income for the three and nine months ended September 30, 2015.

(13) DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

DPL uses derivative instruments in the form of futures 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. 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. In addition, included in derivative assets are PHI Preferred Stock derivatives which are further described in Note (12), “Preferred Stock.”

The tables below identify the balance sheet location and fair values of derivative instruments as of September 30, 2015 and December 31, 2014:

	As of September 30, 2015				
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 assets (current assets)	$ —	$ 18	$ 18	$ —	$ 18
Derivative liabilities (current liabilities)	—	(1)	(1)	1	—
Net Derivative asset	$ —	$ 17	$ 17	$ 1	$ 18

Balance Sheet Caption	As of December 31, 2014 Derivatives Designated as Hedging Instruments	Other Derivative Instruments	Gross Derivative Instruments (millions of dollars)	Effects of Cash Collateral and Netting	Net Derivative Instruments
Derivative assets (current assets)	$ —	$ 3	$ 3	$ —	$ 3
Derivative liabilities (current liabilities)	—	(4)	(4)	4	—
Net Derivative (liability) asset	$ —	$ (1)	$ (1)	$ 4	$ 3

All derivative assets and liabilities available to be offset under master netting arrangements were netted as of September 30, 2015 and December 31, 2014. The amount of cash collateral that was offset against these derivative positions is as follows:

	September 30, 2015	December 31, 2014
	(millions of dollars)	
Cash collateral pledged to counterparties with the right to reclaim (a)	$ 1	$ 4

(a) Includes cash deposits on commodity brokerage accounts.

As of September 30, 2015 and December 31, 2014, 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 Included in Accumulated Other Comprehensive Loss

PHI also may use 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 interest expense over the life of the debt issued as interest payments are made.

The tables below provide details regarding terminated cash flow hedges included in PHI’s consolidated balance sheets as of September 30, 2015 and 2014. The data in the following tables indicate the cumulative net loss after-tax related to terminated 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, 2015 Accumulated Other Comprehensive Loss After-tax	Portion Expected to be Reclassified to Income during the Next 12 Months	Maximum Term
	(millions of dollars)		
Interest rate	$ 8	$ 1	203 months
Total	$ 8	$ 1	

Contracts	As of September 30, 2014 Accumulated Other Comprehensive Loss After-tax	Portion Expected to be Reclassified to Income during the Next 12 Months	Maximum Term
	(millions of dollars)		
Interest rate	$ 9	$ 1	215 months
Total	$ 9	$ 1	

Other Derivative Activity

DPL has 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 addition, in accordance with FASB guidance on regulated operations, regulatory liabilities or regulatory assets of the same amount 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. The following table shows the net unrealized and net realized derivative gains and losses arising during the period associated with these derivatives that were recognized in the consolidated statements of income (through Fuel and purchased energy expense) and that were also deferred as Regulatory liabilities and Regulatory assets, respectively, for the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(millions of dollars)			
Net unrealized (loss) gain arising during the period	$ (1)	$ (1)	$ (2)	$ 1
Net realized (loss) gain recognized during the period	(1)	—	(5)	3

As of September 30, 2015 and December 31, 2014, the quantities and positions of DPL's net outstanding natural gas commodity forward contracts that did not qualify for hedge accounting were:

	September 30, 2015		December 31, 2014	
Commodity	**Quantity**	**Net Position**	**Quantity**	**Net Position**
DPL – Natural gas (One Million British Thermal Units)	3,760,000	Long	3,892,500	Long

In addition, PHI recorded derivative assets for the embedded call and redemption features on the shares of Preferred Stock as further described in Note (12), "Preferred Stock."

(14) FAIR VALUE DISCLOSURES

Financial Instruments Measured at Fair Value on a Recurring Basis

PHI applies FASB guidance on fair value measurement (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, 2015 and December 31, 2014. 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	Fair Value Measurements at September 30, 2015			
	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				
Preferred stock	$ 18	$ —	$ —	$ 18
Cash equivalents and restricted cash equivalents				
Treasury funds	285	285	—	—
Executive deferred compensation plan assets				
Money market funds and short-term investments	27	13	14	—
Life insurance contracts	45	—	26	19
Total	$ 375	$ 298	$ 40	$ 37
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 1	$ 1	$ —	$ —
Executive deferred compensation plan liabilities				
Life insurance contracts	28	—	28	—
Total	$ 29	$ 1	$ 28	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the nine months ended September 30, 2015.
(b) The fair values of derivative liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

Description	Fair Value Measurements at December 31, 2014			
	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				
Preferred stock	$ 3	$ —	$ —	$ 3
Restricted cash equivalents				
Treasury funds	38	38	—	—
Executive deferred compensation plan assets				
Money market funds and short-term investments	35	14	21	—
Life insurance contracts	46	—	27	19
Total	$ 122	$ 52	$ 48	$ 22
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 4	$ 4	$ —	$ —
Executive deferred compensation plan liabilities				
Life insurance contracts	30	—	30	—
Total	$ 34	$ 4	$ 30	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2014.
(b) The fair values of derivative liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

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 Intercontinental Exchange.

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, 2015. 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 classified as level 3 include embedded call and redemption features on the Preferred Stock as further discussed in Note (12), “Preferred Stock.”

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, 2015 and 2014 are shown below:

	Nine Months Ended September 30, 2015	
	Preferred Stock	Life Insurance Contracts
	(millions of dollars)	
Beginning balance as of January 1	$ 3	$ 19
Total gains (losses) (realized and unrealized):		
Included in income	15	4
Included in accumulated other comprehensive loss	—	—
Included in regulatory liabilities	—	—
Purchases	—	—
Issuances	—	(3)
Settlements	—	(1)
Transfers in (out) of level 3	—	—
Ending balance as of September 30	$ 18	$ 19

	Nine Months Ended September 30, 2014	
	Preferred Stock	Life Insurance Contracts
	(millions of dollars)	
Beginning balance as of January 1	$ —	$ 19
Total gains (losses) (realized and unrealized):		
Included in income	—	3
Included in accumulated other comprehensive loss	—	—
Included in regulatory liabilities	—	—
Purchases	—	—
Issuances	3	(3)
Settlements	—	—
Transfers in (out) of level 3	—	—
Ending balance as of September 30	$ 3	$ 19

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,	
	2015	2014
	(millions of dollars)	
Total net gains included in income for the period	$ 19	$ 3
Change in unrealized gains relating to assets still held at reporting date	$ 17	$ 3

Other Financial Instruments

The estimated fair values of PHI's Long-term debt instruments that are measured at amortized cost in PHI's consolidated financial statements and the associated levels of the estimates within the fair value hierarchy as of September 30, 2015 and December 31, 2014 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 (Transition Bonds) 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 and Pepco Energy Services related to its energy savings and construction 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, 2015			
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)	$5,658	$ —	$ 5,217	$ 441
Transition Bonds (b)	201	—	201	—
Long-term project funding	4	—	—	4
Total	$5,863	$ —	$ 5,418	$ 445

(a) The carrying amount for Long-term debt was $5,099 million as of September 30, 2015.
(b) The carrying amount for Transition Bonds, including amounts due within one year, was $184 million as of September 30, 2015.

	Fair Value Measurements at December 31, 2014			
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)	$5,583	$ —	$ 5,136	$ 447
Transition Bonds (b)	235	—	235	—
Long-term project funding	28	—	—	28
Total	$5,846	$ —	$ 5,371	$ 475

(a) The carrying amount for Long-term debt was $4,807 million as of December 31, 2014.
(b) The carrying amount for Transition Bonds, including amounts due within one year, was $215 million as of December 31, 2014.

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

(15) COMMITMENTS AND CONTINGENCIES

General Litigation and Other Matters

From time to time, PHI and its subsidiaries are named as defendants in litigation, usually relating to general liability or auto liability claims that resulted in personal injury or property damage to third parties. PHI and each of its subsidiaries are self-insured against such claims up to a certain self-insured retention amount and maintain insurance coverage against such claims at higher levels, to the extent deemed prudent by management. In addition, PHI's contracts with its vendors generally require the vendors to name PHI and/or its subsidiaries as additional insureds for the amounts at least equal to PHI's self-insured retention. Further, PHI's contracts with its vendors require the vendors to indemnify PHI for various acts and activities that may give rise to claims against PHI. Loss contingency liabilities for both asserted and unasserted claims are recognized if it is probable that a loss will result from such a claim and if the amounts of the losses can be reasonably estimated. Although the outcome of the claims and proceedings cannot be predicted with any certainty, management believes that there are no existing claims or proceedings that are likely to have a material adverse effect on PHI's or its subsidiaries' financial condition, results of operations or cash flows. At September 30, 2015, PHI had recorded estimated loss contingency liabilities for general litigation totaling approximately $12 million (including amounts related to the matters specifically described below).

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, 2015 are summarized as follows:

		Legacy Generation		
	Transmission and Distribution	Regulated	Non-Regulated	Total
		(millions of dollars)		
Beginning balance as of January 1	$ 17	$ 6	$ 5	$ 28
Accruals	3	2	—	5
Payments	3	1	—	4
Ending balance as of September 30	17	7	5	29
Less amounts in Other Current Liabilities	4	1	—	5
Amounts in Other Deferred Credits	$ 13	$ 6	$ 5	$ 24

Conectiv Energy Wholesale Power Generation Sites

In July 2010, PHI sold the wholesale power generation business of Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries (Conectiv Energy) 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 PHI's 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 that any financial consequences that could arise from this inquiry would 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 from 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 the Peck Iron and 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 September 2011, EPA initiated a remedial investigation/feasibility study (RI/FS) for the site using federal funds. Pepco cannot at this time estimate an amount or range of reasonably possible loss associated with this RI/FS, any remediation activities to be performed at the site or any other costs that EPA might seek to impose on Pepco.

Benning Road Site

Contamination of Lower Anacostia River

In September 2010, PHI received a letter from EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site was formerly the location of a Pepco Energy Services electric generating facility. That generating facility was deactivated in June 2012 and plant structure demolition was completed in July 2015. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. The principal contaminants allegedly 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 Energy and Environment (DOEE) (formerly the District of Columbia Department of the Environment), which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15 acre portion of the adjacent Anacostia River. The RI/FS will form the basis for DOEE’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 DOEE will look to Pepco and Pepco Energy Services 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.

The remedial investigation field work began in January 2013 and was completed in December 2014. In addition, in conjunction with the power plant demolition activities, Pepco and Pepco Energy Services collected soil samples adjacent to and beneath the concrete basins for the dismantled cooling towers for the generating facility. This sampling showed localized areas of soil contamination associated with the cooling tower basins, and, in late 2015, Pepco and Pepco Energy Services expect to implement a plan approved by DOEE to remove contaminated soil in conjunction with the demolition and removal of the concrete basins. On April 30, 2015, Pepco and Pepco Energy Services submitted a draft Remedial Investigation (RI) Report to DOEE. After review and comment by DOEE and the public, Pepco and Pepco Energy Services will revise the draft RI Report as appropriate to address comments received. Concurrent with DOEE’s review of the draft RI Report, Pepco and Pepco Energy Services are proceeding to plan and conduct a treatability study to support the evaluation in the Feasibility Study (FS) of possible remedial alternatives. The treatability study is expected to include gathering additional field data and conducting pilot tests to assess the suitability of possible remedial technologies and to quantify the scope of remedial actions that may be warranted. Once the treatability study work has been completed, Pepco and Pepco Energy Services will prepare and submit a treatability study report for DOEE’s review and approval, to be followed by the preparation and submission of a draft FS Report. After public review and comment on the draft FS Report, Pepco and Pepco Energy Services will revise the draft FS Report as appropriate to address comments received and will submit a final FS Report to DOEE.

Upon DOEE's approval of the final RI and FS Reports, Pepco and Pepco Energy Services will have satisfied their obligations under the consent decree. At that point, DOEE will prepare a Proposed Plan regarding further response actions based on the results of the RI/FS. After considering public comment on the Proposed Plan, DOEE will issue a Record of Decision identifying any further response actions determined to be necessary.

DOEE, Pepco and Pepco Energy Services must submit their next joint status report to the court regarding progress on the RI/FS by May 24, 2016.

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."

NPDES Permit Limit Exceedances

Pepco holds a National Pollutant Discharge Elimination System (NPDES) permit issued by EPA with a July 19, 2009 effective date, which authorizes discharges from the Benning Road site, including the Pepco Energy Services generating facility previously located on the site that was deactivated in 2012 and has been demolished. The 2009 permit for the first time imposed numerical limits on the allowable concentration of certain metals in storm water discharged from the site into the Anacostia River as determined by EPA to be necessary to meet the applicable District of Columbia surface water quality standards. The permit contemplated that Pepco would meet these limits over time through the use of best management practices (BMPs). As of December 2012, Pepco completed the implementation of the first two phases of BMPs identified in a plan approved by EPA (consisting principally of installing metal absorbing filters to capture contaminants from storm water flows, removing stored equipment from areas exposed to the weather, covering and painting exposed metal pipes, and covering and cleaning dumpsters). These measures were effective in reducing metal concentrations in storm water discharges, but were not sufficient to meet all of the numerical limits for metals. Quarterly monitoring results since the issuance of the permit have shown consistent exceedances of the limits for copper and zinc, as well as occasional exceedances for iron and lead.

The NPDES permit was due to expire on June 19, 2014. Pepco submitted a permit renewal application on December 17, 2013. In November 2014, EPA advised Pepco that it will not renew the permit until the Benning Road site has come into compliance with the existing permit limits. The current permit remains in effect pending EPA's action on the renewal application. In December 2014, Pepco submitted a plan to EPA to implement the third phase of BMPs recommended in the original permit compliance plan with the objective of achieving full compliance with the permit limits for metals by the end of 2015 and Pepco immediately began to implement the additional BMPs in accordance with the plan. On September 1, 2015, Pepco submitted a report to EPA on the status of implementation of the third phase of BMPs. As of that date, Pepco had fully implemented most of the elements of the Phase 3 plan, including installation of upgraded inlet controls (filters and booms), enhanced inspection and maintenance of inlets, removal of materials and equipment from exposure to storm water, and removal of accumulated sediments from the underground storm drains. Although the most recent sampling results show continued progress toward meeting the permit limits for metals, it appears that some form of storm water treatment prior to discharge will be necessary, and Pepco has begun the process of evaluating treatment options. The nature and scope of the necessary treatment system, and the amount of the associated capital expenditures, will not be known until Pepco has completed the evaluation and design process.

Pepco is currently engaged in discussions with representatives from EPA and the DOJ regarding permit compliance. The DOJ and EPA representatives have advised that they will expect Pepco to enter into a consent decree, in connection with a Clean Water Act civil enforcement action to be filed by EPA, that will establish further requirements to achieve compliance with the permit limits, including the design and installation of an appropriate storm water treatment system, and that the consent decree also will include civil penalties for noncompliance. The amount of such penalties is not known or estimable at this time.

On September 11, 2015, Anacostia Riverkeeper sent Pepco a letter stating its intention to file a citizen suit under the Clean Water Act alleging that Pepco is in violation of the Benning NPDES permit with respect to the discharge of storm water. Such a suit cannot be filed for at least 60 days from the date of this notice letter. Based on discussions with EPA and DOJ, Pepco expects that EPA will file an enforcement action in Federal district court prior to the expiration of the 60-day waiting period that will lead to a consent decree addressing the storm water discharge issues. Such an EPA enforcement action should preclude Anacostia Riverkeeper from proceeding with any separate citizen suit.

If the Phase 3 BMPs are not adequate to achieve consistent compliance with the permit limits, it is possible that a capital project to install a storm water treatment system may be required as part of any consent decree to resolve the expected EPA enforcement. The need for any such capital expenditures will not be known until Pepco has fully implemented the Phase 3 BMPs and engaged in further discussions with EPA and DOJ.

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.

In March 2014, Pepco and DOEE entered into a consent decree to resolve a threatened DOEE enforcement action, the terms of which include a combination of a civil penalty and a Supplemental Environmental Project (SEP) with a total cost to Pepco of $875,000. The consent decree was approved and entered by the District of Columbia Superior Court on April 4, 2014. Pepco has paid the $250,000 civil penalty imposed under the consent decree and, pursuant to the consent decree, has made a one-time donation in the amount of $25,000 to the Northeast Environmental Enforcement Training Fund, Inc., a non-profit organization that funds scholarships for environmental enforcement training. The consent decree confirmed that no further actions are required by Pepco to investigate, assess or remediate impacts to the river from the mineral oil release. To implement the SEP, Pepco has entered into an agreement with Living Classrooms Foundation, Inc., a non-profit educational organization, to provide $600,000 to fund the design, installation and operation of a trash collection system at a storm water outfall that drains to the Anacostia River. DOEE approved the design for the trash collection system and efforts to secure necessary permits have commenced. Pepco expects that this system will be constructed and placed into operation by the end of 2016, which will satisfy Pepco’s obligations under the consent decree. On September 11, 2015, Pepco and DOEE filed a joint report with the D.C. Superior Court on the status of the trash cage project and other elements of the consent decree. The court accepted that report and scheduled the next status hearing in this matter for September 23, 2016.

The consent decree did not resolve potential claims under federal law for natural resource damages resulting from the mineral oil release. Pepco has engaged in separate discussions with DOEE and the federal resource trustees regarding the settlement of a possible natural resource damages claim under federal law. In July 2013, Pepco submitted a natural resource damage assessment to DOEE and the federal trustees that proposed monetary compensation for such damages in the range of $106,000 to $161,000. By letter dated September 16, 2015, the U.S. Department of Interior, on behalf of the trustees, made a confidential counter-proposal for settlement of the natural resource damage claim. Pepco is currently evaluating that proposal and has initiated discussions with the trustees. Based on the terms of the trustees' proposal, PHI and Pepco do not believe that the resolution of the federal natural resource damages claim will have a material adverse effect on their respective financial condition, results of operations or cash flows.

As a result of the mineral oil release, Pepco implemented certain interim operational changes to the secondary containment systems at the facility, which involve pumping accumulated storm water to an above-ground holding tank for off-site disposal. Pepco is continuing to use the above-ground holding tank to manage storm water from the secondary containment system while it evaluates other technical and regulatory options.

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

Metal Bank Site

In the first quarter of 2013, the National Oceanic and Atmospheric Administration (NOAA) contacted Pepco and 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 Cottman Avenue Superfund Site located in Philadelphia, Pennsylvania. Pepco and DPL executed a tolling agreement, which has been extended to March 15, 2016, and will continue 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 NRG Energy, Inc. (as successor to GenOn MD Ash Management, LLC) (NRG). In July 2013, while reserving its rights and related defenses under a 2000 agreement covering the sale of this site, Pepco indicated 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 and, by letter dated October 18, 2013, MDE approved the schedule.

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 NRG under the 2000 sale agreement.

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

Virginia Department of Environmental Quality Notice of Violation

On February 3, 2015, the Virginia Department of Environmental Quality (VDEQ) issued a notice of violation (NOV) to DPL in connection with alleged violations of state water control laws and regulations associated with recent construction activities undertaken to replace certain transmission facilities. The NOV informed DPL of information on which VDEQ may rely to institute an administrative or judicial enforcement action, requested a meeting, and stated that DPL may be asked to enter into a consent order to formalize a plan and schedule of corrective action and settle any outstanding issues regarding the matter including the assessment of civil charges. At a February 20, 2015 meeting, VDEQ confirmed that the NOV would be resolved through a consent order, which will require the payment of a penalty, but did not specify the potential penalty amount. DPL will pursue recovery of the restoration costs for this matter from the contractor responsible for the vegetation management activities that gave rise to the alleged violations. PHI and DPL do not believe that the remediation costs to resolve this matter will have a material adverse effect on their respective financial condition, results of operations or cash flows.

Rock Creek Mineral Oil Release

In late August 2015, a Pepco underground transmission line in the District of Columbia was damaged by a third party performing directional drilling for the installation of other underground utilities, resulting in the release of non-toxic mineral oil surrounding the transmission line into the surrounding soil, and a small amount also reached Rock Creek through a storm drain. Pepco notified regulatory authorities, and Pepco and its spill response contractors placed booms in Rock Creek, blocked the storm drain to prevent the release of mineral oil into the creek and commenced remediation of soil around the transmission line and the Rock Creek shoreline. Pepco estimates that approximately 6,100 gallons of mineral oil were released and that its remediation efforts recovered approximately 80 percent of the amount released. Pepco's remediation efforts are ongoing under the direction of the DOEE and in collaboration with the National Park Service, the Smithsonian Institution/National Zoo and EPA. To the extent recovery is available against any party who contributed to this loss, PHI and Pepco will pursue such action. PHI and Pepco continue to investigate the cause of the incident, the parties involved, and legal responsibility under District of Columbia law, but do not believe that the remediation costs to resolve this matter will have a material adverse effect on their respective financial condition, results of operations or cash flows.

PHI's 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 Internal Revenue Service (IRS) as a sale-in, lease-out, or SILO, transaction. During the second and third quarters of 2013, PHI terminated early all of its remaining cross-border energy lease investments.

Since 2005, PHI's former 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 Exam Division, respectively, and are not presently a part of the U.S. Court of Federal Claims litigation.

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 believed that its tax position with regard to its former cross-border energy lease investments was 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 after-tax charge of $377 million 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 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 has been recorded.

In the event that the IRS were to be successful in disallowing 100% of the tax benefits associated with these lease investments and recharacterize 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 effected during the second and third quarters of 2013 was used to repay the short-term borrowings utilized to fund the advanced payment.

In order to mitigate the cost of continued litigation related to the cross-border energy lease investments, PHI and its subsidiaries have entered into discussions with the IRS with the intention of seeking a settlement of all tax issues for open tax years 2001 through 2011, including the cross-border energy lease issue. PHI currently believes that it is possible that a settlement with the IRS may be reached in 2015 or 2016. Further discovery in the case is stayed until November 19, 2015, pursuant to an order issued by the court on August 20, 2015.

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, 2015, 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 were as follows:

	Guarantor				
	PHI	**Pepco**	**DPL**	**ACE**	**Total**
		(millions of dollars)			
Guarantees associated with disposal of Conectiv Energy assets (a)	$13	$ —	$—	$—	$ 13
Guaranteed lease residual values (b)	3	6	6	5	20
Total	$16	$ 6	$ 6	$ 5	$ 33

(a) 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.

(b) 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 $52 million, $10 million of which is a guaranty by PHI, $13 million by Pepco, $16 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, 2015 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 $230 million, with the longest guarantee having a remaining term of 23 years; and, (ii) projects under construction was $57 million, with the longest guarantee having a term of 15 years after completion of 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, 2015, 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, 2015, Pepco Energy Services had an accrued liability of $1 million for its energy savings contracts that it established during 2012. There was no significant change in the type of contracts issued during the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014.

Dividends

On October 22, 2015, Pepco Holdings' Board of Directors declared a dividend of $0.27 per share, payable December 31, 2015 to holders of common stock of record on the close of business on December 10, 2015.

On October 22, 2015, Pepco Holdings' Board of Directors also declared a pro-rata dividend in the event the Merger is completed before the close of business on December 10, 2015. The pro-rata dividend is payable 20 days after the Merger is completed to holders of common stock of record as of the day immediately prior to the day the Merger is completed, at a rate of $0.002967 per share per day beginning September 11, 2015, and ending the day before the Merger is completed.

(16) VARIABLE INTEREST ENTITIES

PHI is required to consolidate a variable interest entity (VIE) in accordance with FASB ASC 810 if PHI or a subsidiary is the primary beneficiary of the VIE. The primary beneficiary of a VIE is typically the entity with both the power to direct activities most significantly impacting economic performance of the VIE and the obligation to absorb losses or receive benefits of the VIE that could potentially be significant to the VIE. PHI performs a qualitative analysis to determine whether a variable interest provides a controlling financial interest in any of the VIEs in which PHI or its subsidiaries have an interest. Set forth below are the relationships with respect to which PHI conducted a VIE analysis as of September 30, 2015.

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, 2015, DPL is a party to three land-based wind power purchase agreements (PPAs) in the aggregate amount of 128 MWs, one solar PPA with a 10 MW facility, and a PPA with the Delaware Sustainable Energy Utility (DSEU) to purchase solar renewable energy credits (SRECs). Each of the facilities associated with these PPAs is operational, except for the facilities associated with the PPA with the DSEU, which are expected to be operational within one year. DPL is obligated to purchase energy and RECs in amounts generated and delivered by the wind facilities and SRECs from the solar facility and the DSEU, up to certain amounts (as set forth below) at rates that are primarily fixed under the respective agreements. PHI and DPL have concluded that while VIEs exist under these contracts, consolidation is not required under FASB ASC 810 as DPL is not the primary beneficiary. DPL has not provided financial or other support under these arrangements that it was not previously contractually required to provide during the periods presented, and DPL does not have any intention to provide such additional support.

Because DPL has no equity or debt interest in these renewable energy transactions, the maximum exposure to loss relates primarily to any above-market costs incurred for power, RECs or SRECs. Due to unpredictability in the amount of MWs ultimately purchased under the agreements for purchased renewable energy, RECs and SRECs, PHI and DPL are unable to quantify the maximum exposure to loss, however, the power purchase, REC and SREC costs are recoverable from DPL's customers through regulated rates.

Wind PPAs

DPL is obligated to purchase energy and RECs from one of the wind facilities through 2024 in amounts not to exceed 50 MWs, from a second wind facility through 2031 in amounts not to exceed 40 MWs, and from a third wind facility through 2031 in amounts not to exceed 38 MWs. DPL's aggregate purchases under the three wind PPAs totaled $4 million and $5 million for the three months ended September 30, 2015 and 2014, respectively. DPL's aggregate purchases under the three wind PPAs totaled $20 million and $21 million for the nine months ended September 30, 2015 and 2014, respectively.

Solar PPAs

The term of the PPA with the solar facility is through 2030 and DPL is obligated to purchase SRECs in an amount up to 70 percent of the energy output at a fixed price. The DSEU may enter into 20-year contracts with solar facilities to purchase SRECs for resale to DPL. Under the PPA with the DSEU, at September 30, 2015 and 2014, DPL was obligated to purchase SRECs in amounts not to exceed 28 MWs and 19 MWs, respectively, at annually determined auction rates. DPL's purchases under these solar agreements were $2 million and $1 million for the three months ended September 30, 2015 and 2014, respectively. DPL's purchases under these solar agreements were $4 million and $3 million for the nine months ended September 30, 2015 and 2014.

Fuel Cell Facilities

On October 18, 2011, the 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 acts solely as an agent to collect payments in advance from its distribution customers and remit them to the qualified fuel cell provider for each MW hour of energy produced by the fuel cell facilities through 2033. The RPS provides for a reduction in DPL's REC requirements based upon the actual energy output of the facilities. PHI and DPL have concluded that while a VIE exists as a result of this relationship, consolidation is not required under FASB ASC 810 as DPL is not the primary beneficiary. For the three months ended September 30, 2015 and 2014, 56,388 and 56,335 megawatt hours, respectively, were produced from fuel cell facilities placed in service under the tariff. For the nine months ended September 30, 2015 and 2014, 170,028 and 165,878 megawatt hours, respectively, were produced from fuel cell facilities placed in service under the tariff. DPL billed $9 million and $8 million to distribution customers with respect to energy produced by these facilities for the three months ended September 30, 2015 and 2014, respectively. DPL billed $28 million and $26 million to distribution customers with respect to energy produced by these facilities for the nine months ended September 30, 2015 and 2014, respectively.

ACE Power Purchase Agreements

ACE is a party to three PPAs with unaffiliated NUGs totaling 459 MWs. One of the agreements ends in 2016 and the other two end in 2024. PHI and ACE have no equity or debt invested in these entities. In performing its VIE analysis, 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 has applied the scope exemption from the consolidation guidance.

Because ACE has no equity or debt invested in the NUGs, the maximum exposure to loss relates primarily to any above-market costs incurred for power. Due to unpredictability in the pricing for purchased energy under the PPAs, PHI and ACE are unable to quantify the maximum exposure to loss. The power purchase costs are recoverable from ACE's customers through regulated rates. Purchase activities with the NUGs, including excess power purchases not covered by the PPAs, for the three months ended September 30, 2015 and 2014, were approximately $52 million and $56 million, respectively, of which approximately $50 million and $52 million, respectively, consisted of power purchases under the PPAs. Purchase activities with the NUGs, including excess power purchases not covered by the PPAs, for the nine months ended September 30, 2015 and 2014, were approximately $160 million and $182 million, respectively, of which approximately $151 million and $159 million, respectively, consisted of power purchases under the PPAs.

ACE Funding

In 2001, ACE established ACE Funding solely for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of Transition Bonds. The proceeds of the sale of each series of Transition Bonds were transferred to ACE in exchange for the transfer by ACE to ACE Funding of the right to collect a non-bypassable Transition Bond Charge (representing revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees) from ACE customers pursuant to bondable stranded costs rate orders issued by the 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). 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 Transition Bonds have recourse only to the assets of ACE Funding. ACE owns 100 percent of the equity of ACE Funding, and PHI and ACE consolidate ACE Funding in their consolidated financial statements as ACE is the primary beneficiary of ACE Funding under the variable interest entity consolidation guidance.

(17) ACCUMULATED OTHER COMPREHENSIVE LOSS

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(millions of dollars)			
Balance at beginning of the period	$ (42)	$ (35)	$ (46)	$ (34)
Treasury Lock				
Balance at beginning of the period	(9)	(9)	(9)	(9)
Amount of pre-tax loss reclassified to Interest expense	1	—	1	—
Income tax benefit	—	—	—	—
Balance as of September 30	(8)	(9)	(8)	(9)
Pension and Other Postretirement Benefits				
Balance at beginning of the period	(33)	(26)	(37)	(25)
Amount of amortization of net prior service cost and actuarial loss reclassified to Other operation and maintenance expense	2	2	7	—
Income tax expense (benefit)	2	—	3	(1)
Balance as of September 30	(33)	(24)	(33)	(24)
Balance as of September 30	$ (41)	$ (33)	$ (41)	$ (33)

18) SUBSEQUENT EVENT

Land Sale

On October 16, 2015, Pepco entered into a purchase and sale agreement with a third party to sell a two-acre parcel of unimproved land, held currently as non-utility property within Property, plant and equipment, with an allocated carrying value of $5 million at a purchase price of $14 million. The purchase and sale agreement also provides the third party with an option to purchase an additional 1.8-acre land parcel directly adjacent to the property with an allocated carrying value of $4 million at a purchase price of $13 million. The sale of the two-acre parcel is expected to close in the fourth quarter of 2015.

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(millions of dollars)			
Operating Revenue	$ 612	$ 587	$ 1,686	$ 1,630
Operating Expenses				
Purchased energy	213	205	606	612
Other operation and maintenance	112	103	328	287
Depreciation and amortization	74	59	207	171
Other taxes	98	95	284	275
Total Operating Expenses	497	462	1,425	1,345
Operating Income	115	125	261	285
Other Income (Expenses)				
Interest expense	(31)	(29)	(92)	(86)
Other income	8	9	21	28
Total Other Expenses	(23)	(20)	(71)	(58)
Income Before Income Tax Expense	92	105	190	227
Income Tax Expense	32	38	62	82
Net Income	$ 60	$ 67	$ 128	$ 145

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

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

	September 30, 2015	December 31, 2014
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 10	$ 6
Restricted cash equivalents	2	5
Accounts receivable, less allowance for uncollectible accounts of $17 million and $16 million, respectively	418	315
Inventories	67	62
Deferred income tax assets, net	6	14
Income taxes and related accrued interest receivable	95	94
Prepaid expenses and other	24	21
Total Current Assets	622	517
OTHER ASSETS		
Regulatory assets	695	697
Prepaid pension expense	298	316
Investment in trust	26	34
Income taxes and related accrued interest receivable	30	30
Other	73	71
Total Other Assets	1,122	1,148
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	7,949	7,764
Accumulated depreciation	(2,773)	(2,816)
Net Property, Plant and Equipment	5,176	4,948
TOTAL ASSETS	$ 6,920	$ 6,613

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

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

	September 30, 2015	December 31, 2014
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 48	$ 104
Current portion of long-term debt and project funding	—	12
Accounts payable	113	94
Accrued liabilities	78	91
Accounts payable due to associated companies	32	30
Capital lease obligations due within one year	11	10
Taxes accrued	28	32
Interest accrued	32	19
Customer deposits	42	44
Other	69	102
Total Current Liabilities	453	538
DEFERRED CREDITS		
Regulatory liabilities	97	104
Deferred income tax liabilities, net	1,636	1,584
Investment tax credits	2	2
Other postretirement benefit obligations	52	57
Other	67	67
Total Deferred Credits	1,854	1,814
OTHER LONG-TERM LIABILITIES		
Long-term debt	2,332	2,124
Capital lease obligations	45	50
Total Other Long-Term Liabilities	2,377	2,174
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	1,122	1,010
Retained earnings	1,114	1,077
Total Equity	2,236	2,087
TOTAL LIABILITIES AND EQUITY	$ 6,920	$ 6,613

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, 2015	Nine Months Ended September 30, 2014
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 128	$ 145
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	207	171
Deferred income taxes	69	161
Gains on sales of land	—	(9)
Changes in:		
Accounts receivable	(103)	(8)
Inventories	(5)	2
Prepaid expenses	(3)	(3)
Regulatory assets and liabilities, net	(90)	(112)
Accounts payable and accrued liabilities	(17)	(16)
Prepaid pension expense, excluding contributions	18	12
Income tax-related prepayments, receivables and payables	(4)	(30)
Interest accrued	13	15
Other assets and liabilities	—	(3)
Net Cash From Operating Activities	213	325
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(374)	(380)
Department of Energy capital reimbursement awards received	—	3
Proceeds from sales of land	—	9
Changes in restricted cash equivalents	3	—
Net other investing activities	14	(4)
Net Cash Used By Investing Activities	(357)	(372)
FINANCING ACTIVITIES		
Dividends paid to Parent	(91)	(46)
Capital contributions from Parent	112	80
Issuances of long-term debt	208	410
Reacquisitions of long-term debt	(12)	(175)
Repayments of short-term debt, net	(56)	(151)
Cost of issuances	(4)	(7)
Net other financing activities	(9)	(1)
Net Cash From Financing Activities	148	110
Net Increase in Cash and Cash Equivalents	4	63
Cash and Cash Equivalents at Beginning of Period	6	9
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 10	$ 72
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash received for income taxes (includes payments from PHI for federal income taxes)	$ (6)	$ (58)

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, 2014	100	$ —	$ 1,010	$ 1,077	$2,087
Net Income	—	—	—	26	26
Capital contribution from Parent	—	—	112	—	112
BALANCE, MARCH 31, 2015	100	—	1,122	1,103	2,225
Net Income	—	—	—	42	42
Dividends on common stock	—	—	—	(31)	(31)
BALANCE, JUNE 30, 2015	100	—	1,122	1,114	2,236
Net Income	—	—	—	60	60
Dividends on common stock	—	—	—	(60)	(60)
BALANCE, SEPTEMBER 30, 2015	100	$ —	$ 1,122	$ 1,114	$2,236

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).

PHI entered into an Agreement and Plan of Merger, dated April 29, 2014, as amended and restated on July 18, 2014 (the Merger Agreement), with Exelon Corporation, a Pennsylvania corporation (Exelon), and Purple Acquisition Corp., a Delaware corporation and an indirect, wholly owned subsidiary of Exelon (Merger Sub), providing for the merger of Merger Sub with and into PHI (the Merger), with PHI surviving the Merger as an indirect, wholly owned subsidiary of Exelon. Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of common stock, par value $0.01 per share, of PHI (other than (i) shares owned by Exelon, Merger Sub or any other direct or indirect wholly owned subsidiary of Exelon and shares owned by PHI or any direct or indirect wholly owned subsidiary of PHI, and in each case not held on behalf of third parties (but not including shares held by PHI in any rabbi trust or similar arrangement in respect of any compensation plan or arrangement) and (ii) shares that are owned by stockholders who have perfected and not withdrawn a demand for appraisal rights pursuant to Delaware law), will be canceled and converted into the right to receive $27.25 in cash, without interest.

In connection with entering into the Merger Agreement, PHI entered into a Subscription Agreement, dated April 29, 2014 (the Subscription Agreement), with Exelon, pursuant to which on April 30, 2014, PHI issued to Exelon 9,000 originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share (the Preferred Stock), for a purchase price of $90 million. Exelon also committed pursuant to the Subscription Agreement to purchase 1,800 originally issued shares of Preferred Stock for a purchase price of $18 million at the end of each 90-day period following the date of the Subscription Agreement until the Merger closes or is terminated, up to a maximum of 18,000 shares of Preferred Stock for a maximum aggregate consideration of $180 million. In accordance with the Subscription Agreement, on each of July 29, 2014, October 27, 2014, January 26, 2015, April 27, 2015 and July 24, 2015, an additional 1,800 shares of Preferred Stock were issued by PHI to Exelon for a purchase price of $18 million. The holders of the Preferred Stock will be entitled to receive a cumulative, non-participating cash dividend of 0.1% per annum, payable quarterly, when, as and if declared by PHI's board of directors. The proceeds from the issuance of the Preferred Stock are not subject to restrictions and are intended to serve as a prepayment of any applicable reverse termination fee payable from Exelon to PHI. The Preferred Stock will be redeemable on the terms and in the circumstances set forth in the Merger Agreement and the Subscription Agreement.

The Merger Agreement provides for certain termination rights for each of PHI and Exelon, and further provides that, upon termination of the Merger Agreement under certain specified circumstances, PHI will be required to pay Exelon a termination fee of $259 million or reimburse Exelon for its expenses up to $40 million (which reimbursement of expenses shall reduce on a dollar for dollar basis any termination fee subsequently payable by PHI), provided, however, that if the Merger Agreement is terminated in connection with an acquisition proposal made under certain circumstances by a person who made an acquisition proposal between April 1, 2014 and the date of the Merger Agreement, the termination fee will be $293 million plus reimbursement of Exelon for its expenses up to $40 million (not subject to offset). In addition, if the Merger Agreement is terminated under certain circumstances due to the failure to obtain required regulatory approvals with respect to the Merger or the breach by Exelon of its obligations in respect of obtaining such regulatory approvals (a Regulatory Termination), PHI will be able to redeem any issued and outstanding Preferred Stock at par value, and in that case, Exelon will be required to pay all documented out-of-pocket expenses incurred by PHI in connection with the Merger Agreement or the transactions contemplated thereby, up to $40 million. If the Merger Agreement is terminated, other than for a Regulatory Termination, PHI will be required to redeem the Preferred Stock at the purchase price of $10,000 per share, plus any unpaid accrued and accumulated dividends thereupon.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (i) the approval of the Merger by the holders of a majority of the outstanding shares of common stock of PHI; (ii) the receipt of regulatory approvals required to consummate the Merger, including approvals from the Federal Energy Regulatory Commission (FERC), the Federal Communications Commission (FCC), the Delaware Public Service Commission (DPSC), the District of Columbia Public Service Commission (DCPSC), the Maryland Public Service Commission (MPSC), the New Jersey Board of Public Utilities (NJBPU) and the Virginia State Corporation Commission (VSCC); (iii) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (the HSR Act); and (iv) other customary closing conditions, including (a) the accuracy of each party's representations and warranties (subject to customary materiality qualifiers) and (b) each party's compliance with its obligations and covenants contained in the Merger Agreement (including covenants that may limit, restrict or prohibit PHI and its subsidiaries from taking specified actions during the period between the date of the Merger Agreement and the closing of the Merger or the termination of the Merger Agreement). In addition, the obligations of Exelon and Merger Sub to consummate the Merger are subject to the required regulatory approvals not imposing terms, conditions, obligations or commitments, individually or in the aggregate, that constitute a burdensome condition (as defined in the Merger Agreement). For additional discussion, see Note (6), "Regulatory Matters – Merger Approval Proceedings."

On September 23, 2014, the stockholders of PHI approved the Merger, on October 7, 2014, the VSCC approved the Merger, and on November 20, 2014, FERC approved the Merger. In addition, the transfer of control of certain communications licenses held by certain of PHI's subsidiaries has been approved by the FCC. The NJBPU approved the Merger on February 11, 2015, and on October 15, 2015, voted to extend the effectiveness of its approval until June 30, 2016. The DPSC approved the Merger on May 19, 2015.

On December 22, 2014, the waiting period under the HSR Act expired. Although the Department of Justice (DOJ) allowed the waiting period under the HSR Act to expire without taking any action with respect to the Merger, the DOJ has not advised PHI that it has concluded its investigation. The expiration of the HSR Act waiting period allows for the closing of the Merger at any time on or before December 21, 2015. If the Merger is not completed by that date the parties will be required to refile the required Notification and Report Forms with the DOJ and Federal Trade Commission (FTC), which will restart the 30-day waiting period required by the HSR Act, during which time the Merger may not be consummated, unless these agencies authorize the early termination of the waiting period. PHI and Exelon currently anticipate that they will refile with the DOJ and FTC in November 2015.

On May 15, 2015, the MPSC approved the Merger, with conditions, including conditions that modify and supplement those originally proposed. On May 18, 2015, PHI and Exelon announced that they had committed to fulfill the modified, more stringent conditions and package of customer benefits imposed by the MPSC. Multiple parties have filed petitions for judicial review of the MPSC order by the Circuit Court of Queen Anne's County, Maryland, seeking to appeal the MPSC order. PHI is vigorously contesting these appeals. The MPSC order remains in effect during the appeals process. At this time, PHI is unable to predict the outcome of the proceeding.

On August 25, 2015, the DCPSC announced at a public meeting that it had denied the merger application, and on August 27, 2015, the DCPSC issued its written order related to the Merger. On September 28, 2015, Exelon, PHI and Pepco, and certain of their respective affiliates, filed an application for reconsideration with the DCPSC requesting reconsideration of the DCPSC order related to the Merger.

On October 6, 2015, Exelon, PHI and Pepco, and certain of their respective affiliates, entered into a Nonunanimous Full Settlement Agreement and Stipulation (the DC Settlement Agreement) with the District of Columbia Government, the Office of the People's Counsel and other parties, which DC Settlement Agreement contains commitments from Exelon and PHI above those contained in their original merger application.

Also on October 6, 2015, PHI, Exelon and Merger Sub entered into a Letter Agreement (the Letter Agreement), setting forth the terms and conditions under which the parties will file with the DCPSC (a) a Motion of Joint Applicants to Reopen the Record in Formal Case No. 1119 to Allow for Consideration of the DC Settlement Agreement (the Motion to Reopen), or (b) if the Motion to Reopen is not granted, a new merger application, requesting approval of the Merger on the terms and commitments agreed to in the DC Settlement Agreement. Pursuant to the Letter Agreement, PHI and Exelon each agrees, among other things, that neither party will exercise the termination rights each may have under the Merger Agreement on or after October 29, 2015, unless: (i) the DCPSC does not, within 45 days following the date on which the DC Settlement Agreement is filed with the DCPSC (the Settlement Filing Date), set a procedural schedule which allows for a final order for approval of the Merger within 150 days after the Settlement Filing Date, (ii) the DCPSC sets a schedule for action which does not allow for a final order for approval of the Merger within 150 days after the Settlement Filing Date, (iii) the DCPSC fails to issue a final order approving the Merger and the DC Settlement Agreement as filed without condition or modification within 150 days after the Settlement Filing Date, (iv) the DCPSC issues a final order denying approval of the Merger or the DC Settlement Agreement or adds conditions or makes modifications to the DC Settlement Agreement, (v) the DC Settlement Agreement is terminated for any reason, or (vi) on or after the date that is 151 days after the Settlement Filing Date a condition to closing of the Merger has not been satisfied or waived (other than those conditions that by their nature are to be satisfied at the closing). The Letter Agreement also provides that, subject to certain conditions, Exelon may, following receipt of all regulatory approvals consistent with the DC Settlement Agreement, delay closing of the Merger for up to 30 days to engage in capital markets transactions to raise additional funds required to consummate the Merger.

On October 6, 2015, following execution of the DC Settlement Agreement and the Letter Agreement, Exelon, PHI and Pepco, and certain of their respective affiliates, filed with the DCPSC the Motion to Reopen requesting consideration of the DC Settlement Agreement and approval of the Merger on such terms and conditions set forth in the DC Settlement Agreement, without condition or modification, and to stay further proceedings on the application for reconsideration filed by the parties on September 28, 2015 and suspend the time period for reconsideration pending the DCPSC’s consideration of the DC Settlement Agreement.

(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, 2014. 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, 2015, in accordance with GAAP. The year-end December 31, 2014 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, 2015 may not be indicative of results that will be realized for the full year ending December 31, 2015.

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, the calculation of future cash flows and fair value amounts for use in asset impairment evaluations, pension and other postretirement benefits assumptions, the assessment of the adequacy of the allowance for uncollectible accounts, 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 loss contingency liabilities for general litigation and auto and other 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 $81 million for each of the three months ended September 30, 2015 and 2014, and $236 million and $233 million for the nine months ended September 30, 2015 and 2014, respectively.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Business Combinations (Accounting Standards Codification (ASC) 805)

In November 2014, the Financial Accounting Standards Board (FASB) issued new recognition and disclosure requirements related to pushdown accounting. The new recognition requirements grant an acquired entity (or its subsidiaries) the option to elect whether and when a new accounting and reporting basis (pushdown accounting) will be applied when an acquirer obtains control of the acquired entity. This election may be made by the acquired entity (or its subsidiaries) for future change-in-control events or for its most recent change-in-control event, and the acquired entity will be required to determine whether pushdown accounting will be applied in the reporting period in which the change-in-control event occurs or in a subsequent reporting period.

The new required disclosures include information that enables financial statement users to evaluate the effects of pushdown accounting. Disclosures are required to be made in the period in which pushdown accounting is applied and are expected to include both qualitative and quantitative information.

The new recognition and disclosure requirements became effective on a prospective basis on November 18, 2014.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Revenue from Contracts with Customers (ASC 606)

In May 2014, the FASB issued new recognition and disclosure requirements for revenue from contracts with customers, which supersedes the existing revenue recognition guidance. The new recognition requirements focus on when the customer obtains control of the goods or services, rather than the current risks and rewards model of recognition. The core principle of the new standard is that an entity will recognize revenue when it transfers goods or services to its customers in an amount that reflects the consideration an entity expects to be entitled to for those goods or services. The new disclosure requirements will include information intended to communicate the nature, amount, timing and any uncertainty of revenue and cash flows from applicable contracts, including any significant judgments and changes in judgments and assets recognized from the costs to obtain or fulfill a contract. Entities will generally be required to make more estimates and use more judgment under the new standard.

The new requirements will be effective for Pepco beginning January 1, 2018, and may be implemented either retrospectively for all periods presented, or as a cumulative-effect adjustment as of January 1, 2018. Early adoption is permitted, but not before January 1, 2017. Pepco is currently evaluating the potential impact of this new guidance on its financial statements and which implementation approach to select.

Presentation of Debt Issuance Costs (ASC 835)

In April 2015, the FASB issued new guidance for the presentation of debt issuance costs on the balance sheet. Debt issuance costs are currently required to be presented on the balance sheet as assets. However, under the new requirements, these debt issuance costs will be offset against the debt to which the costs relate. The new requirements will be effective for Pepco beginning January 1, 2016, and are required to be implemented on a retrospective basis for all periods presented. Early adoption is permitted. Pepco is currently evaluating the potential impact of this new guidance on its financial statements, but the impact is not expected to be material.

Business Combination (ASC 805)

In September 2015, the FASB issued new guidance on adjustments to provisional amounts recognized in a business combination, which are currently recognized on a retrospective basis. Under the new requirements, adjustments will be recognized in the reporting period in which the adjustments are determined. The effects of changes in depreciation, amortization, or other income arising from changes to the provisional amounts, if any, are included in earnings of the reporting period in which the adjustments to the provisional amounts are determined. An entity is also required to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The new requirements will be effective for Pepco beginning January 1, 2016, and are required to be implemented on a prospective basis. Early adoption is permitted. Pepco currently anticipates it may be affected by the new guidance if its Merger with Exelon is consummated.

(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

As further described in Note (1), “Organization,” on April 29, 2014, PHI entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, PHI and its subsidiaries may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than pursuing the conclusion of the pending filings indicated below. To date, Pepco has not requested such consent from Exelon and has not filed any new distribution base rate cases since entering into the Merger Agreement.

Bill Stabilization Adjustment

A decoupling mechanism, the bill stabilization adjustment (BSA), was approved and implemented for Pepco electric service in Maryland and in the District of Columbia.

Maryland

Pepco Electric Distribution Base Rates

2011 Base Rate Proceeding

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 adjusted by Pepco to approximately $66.2 million), based on a requested return on equity (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%. Among other things, the order also authorized Pepco to recover the actual cost of advanced metering infrastructure (AMI) meters installed during the 2011 test year, stating 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 rates became effective on July 20, 2012. The Maryland Office of People's Counsel 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.

2012 Base Rate Proceeding – Phase I

In November 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%. In July 2013, the MPSC issued an order in this proceeding approving an annual rate increase of approximately $27.9 million, based on an ROE of 9.36%. 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 carrying charge is deferred, but only until such cost effectiveness has been demonstrated and such costs are included in rates. However, MPSC's July 2012 order issued in connection with Pepco's 2011 base rate proceeding, which allowed Pepco to recover the costs of meters installed during the 2011 test year for that case, remains in effect.

The July 2013 order also approved a Grid Resiliency Charge, which went into effect on January 1, 2014, 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, before implementing the surcharge, Pepco (i) provides additional information to the MPSC related to performance objectives, milestones and costs, and (ii) 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 rejected certain other cost recovery mechanisms, including Pepco's proposed reliability performance-based mechanism. The new rates were effective on July 12, 2013.

In July 2013, Pepco filed a notice of appeal of the July 2013 order in the Circuit Court for Baltimore City. Other parties also filed notices of appeal, which were consolidated with Pepco's appeal. In its appeal, Pepco asserted that the MPSC erred in failing to grant Pepco an adequate ROE, denying a number of other cost recovery mechanisms and limiting Pepco's test year data to no more than four months of forecasted data in future rate cases. The other parties primarily asserted that the MPSC erred or acted arbitrarily and capriciously in allowing the recovery of certain costs by Pepco, in approving the Grid Resiliency Charge, and in refusing to reduce Pepco's rate base by known and measurable accumulated depreciation. In November 2014, the Circuit Court issued an order reversing the MPSC's decision on Pepco's ROE and directing the MPSC to make more specific findings regarding the impact of improved service reliability and the BSA in calculating Pepco's ROE. On all other issues that were the subject of an appeal, the Circuit Court affirmed the MPSC's July 2013 order. Other parties to this proceeding have filed notices of appeal of the Circuit Court's decision to the Court of Special Appeals, where the case remains pending. Pepco has elected not to appeal the decision of the Circuit Court.

2013 Base Rate Proceeding – Phase I

In December 2013, 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 $43.3 million (adjusted by Pepco to approximately $37.4 million on April 15, 2014), based on a requested ROE of 10.25%. The requested rate increase sought to recover expenses associated with Pepco's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. In July 2014, the MPSC issued an order approving an annual rate increase of approximately $8.75 million, based on an ROE of 9.62%. The new rates became effective on July 4, 2014. In July 2014, Pepco filed a petition for rehearing seeking reconsideration of the recovery of certain expenses, which the MPSC denied by its order issued in November 2014 (described below). In December 2014, Pepco filed a petition for judicial review of this MPSC order with the Circuit Court for Baltimore City. On August 7, 2015, the Circuit Court for Baltimore City affirmed the MPSC's decision and denied Pepco's appeal. Pepco has elected not to appeal the decision of the Circuit Court.

2012 and 2013 Base Rate Proceedings – Phase II

In August 2014, the MPSC issued an order establishing a Phase II proceeding in the 2012 base rate case described above (the 2012 Phase II proceeding) to address the tax implications of Pepco's net operating loss carryforward (NOLC), which had impacted certain of Pepco's rate adjustments in the 2012 base rate proceeding. Pepco filed a motion to dismiss the 2012 Phase II proceeding, asserting that the MPSC no longer has jurisdiction over the 2012 base rate case due to appeals having been filed by numerous parties. In September 2014, the MPSC issued an order staying the 2012 Phase II proceeding until further notice. In a similar Phase II proceeding in the 2013 base rate case described above, the MPSC issued an order in November 2014 upholding Pepco's treatment of the NOLC. Although Pepco believes the November 2014 MPSC order should be dispositive of the issues raised in the 2012 Phase II proceeding, the 2012 Phase II proceeding is expected to remain open until all appeals of the 2012 base rate proceeding are resolved, whereupon the MPSC will have authority to act on Phase II.

FERC Transmission ROE Challenges

In February 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Municipal Electric Corporation, Inc. (DEMEC), filed a joint complaint at FERC against Pepco and its affiliates, Delmarva Power & Light Company (DPL) and Atlantic City Electric Company (ACE), as well as Baltimore Gas and Electric Company (BGE). The complainants challenged the base ROE and certain protocols regarding the formula rate process associated with the transmission service that the 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. The 10.8% base ROE for facilities placed into service prior to 2006 receives 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 this complaint. In August 2014, FERC issued an order setting the matters in this proceeding for hearing, but holding the hearing in abeyance pending settlement discussions. The order also (i) directed that the evidence and analysis presented concerning ROE be guided by the new ROE methodology adopted by FERC in another proceeding (discussed below), and (ii) set a 15-month refund period that commenced on February 27, 2013, should a refund result from this proceeding. After settlement discussions among the parties in this matter reached an impasse, the settlement judge, in November 2014, issued an order terminating the settlement discussions and referring the matter to a presiding administrative law judge.

In June 2014, FERC issued an order in a proceeding in which Pepco was not involved, in which it adopted a new ROE methodology for electric utilities. This new methodology replaces the existing one-step discounted cash flow analysis (which incorporates only short-term growth rates) traditionally used to derive ROE for electric utilities with the two-step discounted cash flow analysis (which incorporates both short-term and long-term measures of growth) used for natural gas and oil pipelines. As a result of the August 2014 FERC order discussed in the preceding paragraph, Pepco applied an estimated ROE based on the two-step methodology announced by FERC for the 15-month period over which its transmission revenues would be subject to refund as a result of the challenge, and recorded estimated reserves for the entire 15-month refund period in the second quarter of 2014.

On December 8, 2014, the parties that filed the February 2013 complaint filed a second complaint against Pepco, DPL, ACE, as well as BGE, regarding the base transmission ROE, seeking a reduction from 10.8% to 8.8%. By order issued on February 9, 2015, FERC established a hearing on the second complaint and established a second 15-month refund period that commenced on December 8, 2014. Consistent with the prior challenge, Pepco applied an estimated ROE based on the two-step methodology described above, and in the fourth quarter of 2014 and in the first, second and third quarters of 2015 established reserves for the estimated refund based on the effective date of the second refund period of December 8, 2014. On February 20, 2015, the chief judge issued an order consolidating the two complaint proceedings and established an initial decision issuance deadline of February 29, 2016. On March 2, 2015, the presiding administrative law judge issued an order establishing a procedural schedule for the consolidated proceedings that provides for the hearing to commence on October 20, 2015.

Also during the third quarter of 2015, Pepco further evaluated the reserves established for each of the two refund periods and, based on an updated assessment of market conditions, developments in other cases before FERC, litigation risk and other factors, increased its reserves to reflect management’s best estimate of the refund that is expected to result from these consolidated proceedings. As of September 30, 2015, Pepco’s reserves for both of the refund periods totaled $11 million. A settlement entered into by the parties regarding the protocols (but not the ROE) raised in the February 2013 complaint was submitted to FERC on July 31, 2015 and is awaiting FERC approval.

To the extent that the final ROE established in these consolidated proceedings is lower than the ROE used to record the estimated reserves with respect to the February 2013 and the December 2014 complaints, each ten basis point reduction in the ROE would result in an increase in required reserves and a reduction of Pepco’s operating income of $1.2 million.

MPSC New Generation Contract Requirement

In April 2012, the MPSC issued an order that requires Maryland electric distribution companies (EDCs) Pepco, DPL and BGE (collectively, the Contract EDCs) to negotiate and enter into a contract with the winning bidder of a competitive bidding process to build one new power plant in the range of 650 to 700 megawatts (MWs) beginning in 2015, in amounts proportional to their relative standard offer service (SOS) loads. Under the terms of the order, the winning bidder was to construct a 661 MW natural gas-fired combined cycle generation plant in Waldorf, Maryland, with an originally expected commercial operation date of June 1, 2015 (which is now deferred pending the outcome of the proceedings discussed below), and each of the Contract EDCs will recover its costs associated with the contract through surcharges on its respective SOS customers.

In response to a complaint filed by a group of generating companies in the PJM Interconnection, LLC region, in September 2013, the U.S. District Court for the District of Maryland (the Federal District Court) 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, in October 2013, in response to appeals filed by the Contract EDCs and other parties, the Maryland Circuit Court for Baltimore City (the Maryland Circuit Court) upheld the MPSC’s orders requiring the Contract EDCs to enter into the contracts.

In October 2013, the Federal District Court issued an order ruling that the contracts are illegal and unenforceable. The Contract EDCs, the Maryland Office of People’s Counsel and one generating company have appealed the Maryland Circuit Court’s decision to the Maryland Court of Special Appeals. In addition, in November 2013 both the winning bidder and the MPSC appealed the Federal District Court decision to the U.S. Court of Appeals for the Fourth Circuit, which affirmed the decision. In November 2014, the winning bidder and the MPSC each petitioned the U.S. Supreme Court to consider hearing an appeal of the Fourth Circuit decision and, on October 19, 2015, the U.S. Supreme Court agreed to review that decision.

Assuming the contracts, as currently written, become effective following the satisfaction of all relevant conditions, including the completion of the proceedings discussed above, Pepco continues to believe that it may be required to record its proportional share of the contracts as derivative instruments at fair value and record related regulatory assets of approximately the same amount because it would be entitled to recover any payments under the contracts from SOS customers. Pepco has 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.

District of Columbia Power Line Undergrounding Initiative

In May 2014, the Council of the District of Columbia enacted the Electric Company Infrastructure Improvement Financing Act of 2014 (the Improvement Financing Act), which provides enabling legislation for the District of Columbia Power Line Undergrounding (DC PLUG) initiative. This $1 billion initiative seeks to selectively place underground some of the District of Columbia's most outage-prone power lines, which lines and surrounding conduit would be owned and maintained by Pepco.

The Improvement Financing Act provides that: (i) Pepco is to fund approximately $500 million of the estimated cost to complete the DC PLUG initiative, recovering those costs through a surcharge on the electric bills of Pepco District of Columbia customers; (ii) $375 million of the DC PLUG initiative cost is to be financed by the District of Columbia's issuance of securitized bonds, which bonds will be repaid through a surcharge on the electric bills of Pepco District of Columbia customers that Pepco will collect on behalf of and remit to the District of Columbia; and (iii) the remaining costs up to $125 million are to be covered by the existing capital projects program of the District of Columbia Department of Transportation (DDOT). Pepco will not earn a return on or a return of the cost of the assets funded with the proceeds of the securitized bonds or assets that are constructed by DDOT under its capital projects program, but ownership and responsibility for the operation and maintenance of such assets will be transferred to Pepco for a nominal amount.

In June 2014, Pepco and DDOT filed a Triennial Plan related to the construction of selected underground feeders in the District of Columbia and recovery of Pepco's investment through a volumetric surcharge (the Triennial Plan), all in accordance with the Improvement Financing Act. In August 2014, Pepco filed an application for the issuance of a financing order to provide for the issuance of the District's bonds and a volumetric surcharge for the District of Columbia to recover the costs associated with the bond issuance (the DDOT surcharge).

In November 2014, the DCPSC issued an order approving the Triennial Plan, including Pepco's volumetric surcharge, and issued the financing order, including approval of the DDOT surcharge. Together these orders permit (i) Pepco and DDOT to commence proposed construction under the Triennial Plan; (ii) the District of Columbia to issue the necessary bonds to fund the District of Columbia's portion of the DC PLUG initiative; and (iii) the establishment of the customer surcharges contemplated by the Improvement Financing Act. In December 2014, a party to the proceeding sought reconsideration from the DCPSC of both decisions. Final decisions denying both requests for reconsideration were issued by the DCPSC on January 22, 2015 and February 2, 2015, respectively.

In March 2015, a party to the DCPSC proceedings filed with the District of Columbia Court of Appeals a petition for review of the order approving the Triennial Plan and the issuance of the financing order. In August 2015, the DCPSC filed a motion with the District of Columbia Court of Appeals to dismiss or, in the alternative, for summary affirmance, which was denied by the court in September 2015. The District of Columbia Court of Appeals is scheduled to hear the case in November 2015. Separately, in June 2015, an agency of the federal government served by Pepco asserted that the DDOT surcharge constitutes a tax on end users from which the federal government is immune. PHI is currently evaluating the assertion and the resolution of this matter will likely delay implementation of the undergrounding initiative.

Merger Approval Proceedings

District of Columbia

On June 18, 2014, Exelon, PHI and Pepco, and certain of their respective affiliates, filed an application with the DCPSC seeking approval of the Merger. To approve the Merger, the DCPSC must find that the Merger is in the public interest. In an order issued August 22, 2014, the DCPSC stated that to make the determination of whether the transaction is in the public interest, it will analyze the transaction in the context of seven factors to determine whether the transaction balances the interests of shareholders and investors with ratepayers and the community, whether the benefits to shareholders do or do not come at the expense of the ratepayers, and whether the transaction produces a direct and tangible benefit to ratepayers. The seven factors identified by the DCPSC are the effects of the transaction on: (i) ratepayers, shareholders, the financial health of the utility standing alone and as merged, and the local economy; (ii) utility management and administrative operations; (iii) the public safety and the safety and reliability of services; (iv) risks associated with all of the affiliated non-jurisdictional business operations, including nuclear operations, of the applicants; (v) the DCPSC's ability to regulate the utility effectively following the Merger; (vi) competition in the local retail and wholesale markets that impacts the District and District ratepayers; and (vii) conservation of natural resources and preservation of environmental quality. District of Columbia law does not impose any time limit on the DCPSC's review of the Merger. The DCPSC held evidentiary hearings in March and April of 2015 and the record was closed on May 27, 2015.

On August 25, 2015, the DCPSC announced at a public meeting that it had denied the merger application and Pepco Holdings and Exelon indicated that the parties were evaluating all available options, including requesting a rehearing of the DCPSC's decision. On August 27, 2015, the DCPSC issued its written order related to the Merger. On September 28, 2015, Exelon, PHI and Pepco, and certain of their respective affiliates, filed an application for reconsideration before the DCPSC. Following the DCPSC's decision on reconsideration, Exelon and Pepco Holdings have the option of filing further appeals with the DC Court of Appeals.

On October 6, 2015, Exelon, PHI and Pepco, and certain of their respective affiliates, entered into the DC Settlement Agreement with the District of Columbia Government, the Office of the People's Counsel and other parties. Also on October 6, 2015, Exelon, PHI and Pepco, and certain of their respective affiliates filed with the DCPSC the Motion to Reopen requesting consideration of the DC Settlement Agreement and approval of the Merger on such terms and conditions set forth in the DC Settlement Agreement, without condition or modification, and to stay further proceedings on the application for reconsideration filed by the parties on September 28, 2015, and suspend the time period for reconsideration pending the DCPSC's consideration of the DC Settlement Agreement.

Maryland

On August 19, 2014, Exelon, PHI, Pepco, DPL and certain of their respective affiliates, filed an application with the MPSC seeking approval of the Merger. Maryland law requires the MPSC to approve a merger subject to its review if it finds that the merger is consistent with the public interest, convenience and necessity, including its benefits to and impact on consumers. Evidentiary hearings were held beginning on January 26, 2015. On March 10, 2015, Exelon, PHI, Pepco, DPL and certain of their respective affiliates, filed with the MPSC a settlement agreement entered into with one of the stakeholder groups participating in the MPSC approval proceeding. On March 16, 2015, Exelon, PHI, Pepco, DPL and certain of their respective affiliates, filed with the MPSC a settlement agreement entered into with Montgomery and Prince George's Counties in Maryland, and a number of other parties. On May 15, 2015, the MPSC approved the Merger, with conditions, including conditions that modify and supplement those originally proposed. On May 18, 2015, Pepco Holdings and Exelon announced that they had completed their review of the MPSC's order approving the Merger and have committed to fulfill the modified, more stringent conditions and package of customer benefits imposed by the MPSC.

Multiple parties have filed petitions for judicial review of the MPSC order by the Circuit Court of Queen Anne's County, Maryland, seeking to appeal the MPSC order. In connection with these proceedings, the Maryland Office of People's Counsel and several other parties to the Merger proceedings filed motions in the Circuit Court for Queen Anne's County, Maryland, requesting a stay of the MPSC order. On August 7, 2015, the Circuit Court for Queen Anne's County denied the motions for stay. Exelon and Pepco Holdings are vigorously contesting these appeals of the MPSC order. The MPSC order remains in effect during the appeals process. At this time, PHI is unable to predict the outcome of the proceeding.

Virginia

On June 3, 2014, Exelon, PHI, Pepco and DPL, and certain of their respective affiliates, filed an application with the VSCC seeking approval of the Merger. Virginia law provides that, if the VSCC determines, with or without hearing, that adequate service to the public at just and reasonable rates will not be impaired or jeopardized by granting the application for approval, then the VSCC shall approve a merger with such conditions that the VSCC deems to be appropriate in order to satisfy this standard. On October 7, 2014, the VSCC issued an order approving the Merger.

Federal Energy Regulatory Commission

On May 30, 2014, Exelon, PHI, Pepco, DPL and ACE, and certain of their respective affiliates, submitted to FERC a Joint Application for Authorization of Disposition of Jurisdictional Assets and Merger under Section 203 of the Federal Power Act. Under that section, FERC shall approve a merger if it finds that the proposed transaction will be consistent with the public interest. On November 20, 2014, FERC issued an order approving the Merger.

(7) PENSION AND OTHER POSTRETIREMENT BENEFITS

Pepco accounts for its participation in PHI's single-employer plans, PHI's noncontributory retirement plan (the PHI Retirement Plan) and its other postretirement benefits plan, the Pepco Holdings, Inc. Welfare Plan for Retirees (the OPEB Plan), as participation in multiemployer plans. PHI's pension and other postretirement net periodic benefit cost for the three months ended September 30, 2015 and 2014, before intercompany allocations from the PHI Service Company, were $25 million and $16 million, respectively. Pepco's allocated share was $7 million and $5 million, respectively, for the three months ended September 30, 2015 and 2014. PHI's pension and other postretirement net periodic benefit cost for the nine months ended September 30, 2015 and 2014, before intercompany allocations from the PHI Service Company, were $73 million and $44 million, respectively. Pepco's allocated share was $22 million and $16 million, respectively, for the nine months ended September 30, 2015 and 2014.

For the nine months ended September 30, 2015 and 2014, Pepco made no discretionary tax-deductible contributions to the PHI Retirement Plan.

(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, 2013, as permitted under the existing terms of the credit agreement, a request by PHI, Pepco, DPL and ACE to extend the credit facility termination date to August 1, 2018 was approved. All of the terms and conditions as well as pricing remained 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, $200 million, $250 million and $300 million for PHI, Pepco, DPL and ACE, respectively. 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, 2015.

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.

At each of September 30, 2015 and December 31, 2014, 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 $413 million. 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.

Credit Facility Amendment

On May 20, 2014, PHI, Pepco, DPL and ACE entered into an amendment of and consent with respect to the credit agreement (the Consent). PHI was required to obtain the consent of certain of the lenders under the credit facility in order to permit the consummation of the Merger. Pursuant to the Consent, certain of the lenders consented to the consummation of the Merger and the subsequent conversion of PHI from a Delaware corporation to a Delaware limited liability company, provided that the Merger and subsequent conversion are consummated on or before October 29, 2015. In addition, the Consent amends the definition of "Change in Control" in the credit agreement to mean, following consummation of the Merger, an event or series of events by which Exelon no longer owns, directly or indirectly, 100% of the outstanding shares of voting stock of Pepco Holdings. PHI has requested an extension of the Consent to allow for completion of the Merger by June 30, 2016.

Commercial Paper

Pepco maintains an on-going commercial paper program to address its short-term liquidity needs. As of September 30, 2015, the maximum capacity available under the program was $500 million, subject to available borrowing capacity under the credit facility.

Pepco had $48 million of commercial paper outstanding at September 30, 2015. The weighted average interest rate for commercial paper issued by Pepco during the nine months ended September 30, 2015 was 0.43% and the weighted average maturity of all commercial paper issued by Pepco during the nine months ended September 30, 2015 was five days.

Other Financing Activities

Sale of Receivables

On September 28, 2015, Pepco, as seller, entered into a purchase agreement with a buyer to sell receivables from an energy savings project over a period of time pursuant to a task order. The purchase price to be received by Pepco is $5 million. Pursuant to the purchase agreement, following acceptance of the energy savings project by the buyer, the buyer is entitled to receive the contract payments under the task order payable by the customer over approximately 15 years. The energy savings project will be performed by Pepco Energy Services and is expected to be completed by the end of 2017.

During 2014, Pepco, as seller, entered into a purchase agreement with a buyer to sell receivables from an energy savings project pursuant to a task order entered into under a General Services Administration area-wide agreement. The purchase price received by Pepco was $12 million. The energy savings project was performed by Pepco Energy Services and was completed in 2014. Pursuant to the purchase agreement, following acceptance of the energy savings project by the buyer, the buyer was entitled to receive the contract payments under the task order payable by the buyer over approximately 9 years. The energy savings project was accepted during the first quarter of 2015 and the amount was removed from the Current portion of long-term debt and project funding.

(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,			
	2015		2014		2015		2014	
	(millions of dollars)							
Income tax at Federal statutory rate	$ 32	35.0%	$ 37	35.0%	$ 67	35.0%	$ 79	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	5	5.4%	6	5.7%	10	5.3%	13	5.7%
Asset removal costs	(3)	(3.3)%	(4)	(3.8)%	(11)	(5.8)%	(9)	(4.0)%
Other, net	(2)	(2.3)%	(1)	(0.7)%	(4)	(1.9)%	(1)	(0.6)%
Income tax expense	$ 32	34.8%	$ 38	36.2%	$ 62	32.6%	$ 82	36.1%

Changes to the District of Columbia Tax Law

On February 26, 2015, the District of Columbia Fiscal Year 2015 Budget Support Act of 2014 became law, effective January 1, 2015. The law revised the apportionment methodology for corporate tax and included a phase-down of the corporate tax rate from 9.975% to 8.25% by fiscal year 2019. The change in law required Pepco to remeasure its net deferred tax liabilities in the first quarter of 2015. This remeasurement resulted in Pepco reducing its deferred tax liabilities by $23 million in the first quarter of 2015 to reflect the initial reduction in the tax rate from 9.975% to 9.4% for 2015. This reduction to the deferred tax liabilities was offset by a corresponding decrease to Pepco's regulatory assets. Further reductions to the corporate tax rate beyond 2015 will depend upon future revenue projections for the District of Columbia.

(10) FAIR VALUE DISCLOSURES

Financial Instruments Measured at Fair Value on a Recurring Basis

Pepco applies FASB guidance on fair value measurement (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, 2015 and December 31, 2014. 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, 2015			
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 and restricted cash equivalents				
Treasury funds	$ 3	$ 3	$ —	$ —
Executive deferred compensation plan assets				
Money market funds and short-term investments	26	12	14	—
Life insurance contracts	40	—	22	18
Total	$ 69	$ 15	$ 36	$ 18
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 6	$ —	$ 6	$ —
Total	$ 6	$ —	$ 6	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the nine months ended September 30, 2015.

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, 2014			
	(millions of dollars)			
ASSETS				
Restricted cash equivalents				
Treasury fund	$ 5	$ 5	$ —	$ —
Executive deferred compensation plan assets				
Money market funds and short-term investments	34	13	21	—
Life insurance contracts	41	—	23	18
Total	$ 80	$ 18	$ 44	$ 18
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 7	$ —	$ 7	$ —
Total	$ 7	$ —	$ 7	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2014.

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, 2015. 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, 2015 and 2014 are shown below:

	Life Insurance Contracts Nine Months Ended September 30, 2015	2014
	(millions of dollars)	
Beginning balance as of January 1	$ 18	$ 18
Total gains (losses) (realized and unrealized):		
Included in income	4	3
Included in accumulated other comprehensive loss	—	—
Purchases	—	—
Issuances	(4)	(3)
Settlements	—	—
Transfers in (out) of level 3	—	—
Ending balance as of September 30	$ 18	$ 18

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, 2015	2014
	(millions of dollars)	
Total gains included in income for the period	$ 4	$ 3
Change in unrealized gains relating to assets still held at reporting date	$ 2	$ 3

Other Financial Instruments

The estimated fair values of Pepco's Long-term debt instruments that are measured at amortized cost in Pepco's financial statements and the associated levels of the estimates within the fair value hierarchy as of September 30, 2015 and December 31, 2014 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.

The Project funding represents debt instruments issued by Pepco related to its construction contracts. Project funding is categorized as level 3 because PHI concluded that the amortized cost carrying amounts for these instruments approximate fair value, which does not represent a quoted price in an active market.

	Fair Value Measurements at September 30, 2015			
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)	$2,686	$ —	$ 2,686	$ —

(a) The carrying amount for Long-term debt was $2,332 million as of September 30, 2015.

	Fair Value Measurements at December 31, 2014			
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)	$2,624	$ —	$ 2,624	$ —
Project funding	12	—	—	12
Total	$2,636	$ —	$ 2,624	$ 12

(a) The carrying amount for Long-term debt was $2,124 million as of December 31, 2014.

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

(11) COMMITMENTS AND CONTINGENCIES

General Litigation

From time to time, Pepco is named as a defendant in litigation, usually relating to general liability or auto liability claims that resulted in personal injury or property damage to third parties. Pepco is self-insured against such claims up to a certain self-insured retention amount and maintains insurance coverage against such claims at higher levels, to the extent deemed prudent by management. In addition, Pepco's contracts with its vendors generally require the vendors to name Pepco as an additional insured for the amount at least equal to Pepco's self-insured retention. Further, Pepco's contracts with its vendors require the vendors to indemnify Pepco for various acts and activities that may give rise to claims against Pepco. Loss contingency liabilities for both asserted and unasserted claims are recognized if it is probable that a loss will result from such a claim and if the amounts of the losses can be reasonably estimated. Although the outcome of the claims and proceedings cannot be predicted with any certainty, management believes that there are no existing claims or proceedings that are likely to have a material adverse effect on Pepco's financial condition, results of operations or cash flows. At September 30, 2015, Pepco had recorded estimated loss contingency liabilities for general litigation totaling approximately $4 million.

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, 2015 are summarized as follows:

	Transmission and Distribution	Legacy Generation - Regulated	Total
		(millions of dollars)	
Beginning balance as of January 1	$ 16	$ 3	$ 19
Accruals	—	2	2
Payments	1	—	1
Ending balance as of September 30	15	5	20
Less amounts in Other Current Liabilities	3	—	3
Amounts in Other Deferred Credits	$ 12	$ 5	$ 17

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 the Peck Iron and 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 September 2011, EPA initiated a remedial investigation/feasibility study (RI/FS) for the site using federal funds. Pepco cannot at this time estimate an amount or range of reasonably possible loss associated with this RI/FS, any remediation activities to be performed at the site or any other costs that EPA might seek to impose on Pepco.

Benning Road Site

Contamination of Lower Anacostia River

In September 2010, PHI received a letter from EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site was formerly the location of a Pepco Energy Services electric generating facility. That generating facility was deactivated in June 2012 and plant structure demolition was completed in July 2015. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. The principal contaminants allegedly 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 Energy and Environment (DOEE) (formerly the District of Columbia Department of the Environment), which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15 acre portion of the adjacent Anacostia River. The RI/FS will form the basis for

DOEE'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 DOEE will look to Pepco and Pepco Energy Services 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.

The remedial investigation field work began in January 2013 and was completed in December 2014. In addition, in conjunction with the power plant demolition activities, Pepco and Pepco Energy Services collected soil samples adjacent to and beneath the concrete basins for the dismantled cooling towers for the generating facility. This sampling showed localized areas of soil contamination associated with the cooling tower basins, and, in late 2015, Pepco and Pepco Energy Services expect to implement a plan approved by DOEE to remove contaminated soil in conjunction with the demolition and removal of the concrete basins. On April 30, 2015, Pepco and Pepco Energy Services submitted a draft Remedial Investigation (RI) Report to DOEE. After review and comment by DOEE and the public, Pepco and Pepco Energy Services will revise the draft RI Report as appropriate to address comments received. Concurrent with DOEE's review of the draft RI Report, Pepco and Pepco Energy Services are proceeding to plan and conduct a treatability study to support the evaluation in the Feasibility Study (FS) of possible remedial alternatives. The treatability study is expected to include gathering additional field data and conducting pilot tests to assess the suitability of possible remedial technologies and to quantify the scope of remedial actions that may be warranted. Once the treatability study work has been completed, Pepco and Pepco Energy Services will prepare and submit a treatability study report for DOEE's review and approval, to be followed by the preparation and submission of a draft FS Report. After public review and comment on the draft FS Report, Pepco and Pepco Energy Services will revise the draft FS Report as appropriate to address comments received and will submit a final FS Report to DOEE.

Upon DOEE's approval of the final RI and FS Reports, Pepco and Pepco Energy Services will have satisfied their obligations under the consent decree. At that point, DOEE will prepare a Proposed Plan regarding further response actions based on the results of the RI/FS. After considering public comment on the Proposed Plan, DOEE will issue a Record of Decision identifying any further response actions determined to be necessary.

DOEE, Pepco and Pepco Energy Services must submit their next joint status report to the court regarding progress on the RI/FS by May 24, 2016.

The remediation costs accrued for this matter are included in the table above in the column entitled "Transmission and Distribution."

NPDES Permit Limit Exceedances

Pepco holds a National Pollutant Discharge Elimination System (NPDES) permit issued by EPA with a July 19, 2009 effective date, which authorizes discharges from the Benning Road site, including the Pepco Energy Services generating facility previously located on the site that was deactivated in 2012 and has been demolished. The 2009 permit for the first time imposed numerical limits on the allowable concentration of certain metals in storm water discharged from the site into the Anacostia River as determined by EPA to be necessary to meet the applicable District of Columbia surface water quality standards. The permit contemplated that Pepco would meet these limits over time through the use of best management practices (BMPs). As of December 2012, Pepco completed the implementation of the first two phases of BMPs identified in a plan approved by EPA (consisting principally of installing metal absorbing filters to capture contaminants from storm water flows, removing stored equipment from areas exposed to the weather, covering and painting exposed metal pipes, and covering and cleaning dumpsters). These measures were effective in reducing metal concentrations in storm water discharges, but were not sufficient to meet all of the numerical limits for metals. Quarterly monitoring results since the issuance of the permit have shown consistent exceedances of the limits for copper and zinc, as well as occasional exceedances for iron and lead.

The NPDES permit was due to expire on June 19, 2014. Pepco submitted a permit renewal application on December 17, 2013. In November 2014, EPA advised Pepco that it will not renew the permit until the Benning Road site has come into compliance with the existing permit limits. The current permit remains in effect pending EPA's action on the renewal application. In December 2014, Pepco submitted a plan to EPA to implement the third phase of BMPs recommended in the original permit compliance plan with the objective of achieving full compliance with the permit limits for metals by the end of 2015 and Pepco immediately began to implement the additional BMPs in accordance with the plan. On September 1, 2015, Pepco submitted a report to EPA on the status of implementation of the third phase of BMPs. As of that date, Pepco had fully implemented most of the elements of the Phase 3 plan, including installation of upgraded inlet controls (filters and booms), enhanced inspection and maintenance of inlets, removal of materials and equipment from exposure to storm water, and removal of accumulated sediments from the underground storm drains. Although the most recent sampling results show continued progress toward meeting the permit limits for metals, it appears that some form of storm water treatment prior to discharge will be necessary, and Pepco has begun the process of evaluating treatment options. The nature and scope of the necessary treatment system, and the amount of the associated capital expenditures, will not be known until Pepco has completed the evaluation and design process.

Pepco is currently engaged in discussions with representatives from EPA and the DOJ regarding permit compliance. The DOJ and EPA representatives have advised that they will expect Pepco to enter into a consent decree, in connection with a Clean Water Act civil enforcement action to be filed by EPA, that will establish further requirements to achieve compliance with the permit limits, including the design and installation of an appropriate storm water treatment system, and that the consent decree also will include civil penalties for noncompliance. The amount of such penalties is not known or estimable at this time.

On September 11, 2015, Anacostia Riverkeeper sent Pepco a letter stating its intention to file a citizen suit under the Clean Water Act alleging that Pepco is in violation of the Benning NPDES permit with respect to the discharge of storm water. Such a suit cannot be filed for at least 60 days from the date of this notice letter. Based on discussions with EPA and DOJ, Pepco expects that EPA will file an enforcement action in Federal district court prior to the expiration of the 60-day waiting period that will lead to a consent decree addressing the storm water discharge issues. Such an EPA enforcement action should preclude Anacostia Riverkeeper from proceeding with any separate citizen suit.

If the Phase 3 BMPs are not adequate to achieve consistent compliance with the permit limits, it is possible that a capital project to install a storm water treatment system may be required as part of any consent decree to resolve the expected EPA enforcement. The need for any such capital expenditures will not be known until Pepco has fully implemented the Phase 3 BMPs and engaged in further discussions with EPA and DOJ.

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.

In March 2014, Pepco and DOEE entered into a consent decree to resolve a threatened DOEE enforcement action, the terms of which include a combination of a civil penalty and a Supplemental Environmental Project (SEP) with a total cost to Pepco of $875,000. The consent decree was approved and entered by the District of Columbia Superior Court on April 4, 2014. Pepco has paid the $250,000 civil penalty imposed under the consent decree and, pursuant to the consent decree, has made a one-time donation in the amount of $25,000 to the Northeast Environmental Enforcement Training Fund, Inc., a non-profit organization that funds scholarships for environmental enforcement training. The consent decree confirmed that no further actions are required by Pepco to investigate, assess or remediate impacts to the river from the mineral oil release. To implement the SEP, Pepco has entered into an agreement with Living Classrooms Foundation, Inc., a non-profit educational organization, to provide $600,000 to fund the design, installation and operation of a trash collection system at a storm water outfall that drains to the Anacostia River. DOEE approved the design for the trash collection system and efforts to secure necessary permits have commenced. Pepco expects that this system will be constructed and placed into operation by the end of 2016, which will satisfy Pepco's obligations under the consent decree. On September 11, 2015, Pepco and

DOEE filed a joint report with the D.C. Superior Court on the status of the trash cage project and other elements of the consent decree. The court accepted that report and scheduled the next status hearing in this matter for September 23, 2016.

The consent decree did not resolve potential claims under federal law for natural resource damages resulting from the mineral oil release. Pepco has engaged in separate discussions with DOEE and the federal resource trustees regarding the settlement of a possible natural resource damages claim under federal law. In July 2013, Pepco submitted a natural resource damage assessment to DOEE and the federal trustees that proposed monetary compensation for such damages in the range of $106,000 to $161,000. By letter dated September 16, 2015, the U.S. Department of Interior, on behalf of the trustees, made a confidential counter-proposal for settlement of the natural resource damage claim. Pepco is currently evaluating that proposal and has initiated discussions with the trustees. Based on the terms of the trustees' proposal, PHI and Pepco do not believe that the resolution of the federal natural resource damages claim will have a material adverse effect on their respective financial condition, results of operations or cash flows.

As a result of the mineral oil release, Pepco implemented certain interim operational changes to the secondary containment systems at the facility, which involve pumping accumulated storm water to an above-ground holding tank for off-site disposal. Pepco is continuing to use the above-ground holding tank to manage storm water from the secondary containment system while it evaluates other technical and regulatory options.

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

Metal Bank Site

In the first quarter of 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 Cottman Avenue Superfund Site located in Philadelphia, Pennsylvania. Pepco executed a tolling agreement, which has been extended to March 15, 2016, and will continue 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 NRG Energy, Inc. (as successor to GenOn MD Ash Management, LLC) (NRG). In July 2013, while reserving its rights and related defenses under a 2000 agreement covering the sale of this site, Pepco indicated 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 and, by letter dated October 18, 2013, MDE approved the schedule.

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 NRG under the 2000 sale agreement.

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

Rock Creek Mineral Oil Release

In late August 2015, a Pepco underground transmission line in the District of Columbia was damaged by a third party performing directional drilling for the installation of other underground utilities, resulting in the release of non-toxic mineral oil surrounding the transmission line into the surrounding soil, and a small amount also reached Rock Creek through a storm drain. Pepco notified regulatory authorities, and Pepco and its spill response contractors placed booms in Rock Creek, blocked the storm drain to prevent the release of mineral oil into the creek and commenced remediation of soil around the transmission line and the Rock Creek shoreline. Pepco estimates that approximately 6,100 gallons of mineral oil were released and that its remediation efforts recovered approximately 80 percent of the amount released. Pepco’s remediation efforts are ongoing under the direction of the DOEE and in collaboration with the National Park Service, the Smithsonian Institution/National Zoo and EPA. To the extent recovery is available against any party who contributed to this loss, PHI and Pepco will pursue such action. PHI and Pepco continue to investigate the cause of the incident, the parties involved, and legal responsibility under District of Columbia law, but do not believe that the remediation costs to resolve this matter will have a material adverse effect on their respective financial condition, results of operations or cash flows.

(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, 2015 and 2014 were approximately $58 million and $55 million, respectively. PHI Service Company costs directly charged or allocated to Pepco for the nine months ended September 30, 2015 and 2014 were approximately $181 million and $163 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 the three months ended September 30, 2015 and 2014 were approximately $5 million and $12 million, respectively. Amounts charged to Pepco by Pepco Energy Services for the nine months ended September 30, 2015 and 2014 were approximately $15 million and $23 million, respectively.

As of September 30, 2015 and December 31, 2014, Pepco had the following balances on its balance sheets due to related parties:

	September 30, 2015	December 31, 2014
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (22)	$ (27)
Pepco Energy Services (b)	(5)	(2)
Other	(5)	(1)
Total	$ (32)	$ (30)

(a) Included in Accounts payable due to associated companies.
(b) Pepco bills customers on behalf of Pepco Energy Services 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.

13) SUBSEQUENT EVENT

Land Sale

On October 16, 2015, Pepco entered into a purchase and sale agreement with a third party to sell a two-acre parcel of unimproved land, held currently as non-utility property within Property, plant and equipment, with an allocated carrying value of $5 million at a purchase price of $14 million. The purchase and sale agreement also provides the third party with an option to purchase an additional 1.8-acre land parcel directly adjacent to the property with an allocated carrying value of $4 million at a purchase price of $13 million. The sale of the two-acre parcel is expected to close in the fourth quarter of 2015.

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
		(millions of dollars)		
Operating Revenue				
Electric	$ 298	$ 289	$ 885	$ 840
Natural gas	19	20	130	145
Total Operating Revenue	317	309	1,015	985
Operating Expenses				
Purchased energy	146	140	444	422
Gas purchased	8	9	66	80
Other operation and maintenance	77	71	235	202
Depreciation and amortization	42	33	117	93
Other taxes	12	11	35	32
Total Operating Expenses	285	264	897	829
Operating Income	32	45	118	156
Other Income (Expenses)				
Interest expense	(12)	(12)	(37)	(35)
Other income	4	3	9	9
Total Other Expenses	(8)	(9)	(28)	(26)
Income Before Income Tax Expense	24	36	90	130
Income Tax Expense	9	13	35	51
Net Income	$ 15	$ 23	$ 55	$ 79

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

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

	September 30, 2015	December 31, 2014
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 5	$ 4
Restricted cash equivalents	—	5
Accounts receivable, less allowance for uncollectible accounts of $19 million and $11 million, respectively	209	193
Inventories	46	55
Deferred income tax assets, net	20	16
Income taxes and related accrued interest receivable	34	34
Prepaid expenses and other	12	12
Total Current Assets	326	319
OTHER ASSETS		
Goodwill	8	8
Regulatory assets	359	356
Prepaid pension expense	209	220
Income taxes and related accrued interest receivable	4	4
Other	12	12
Total Other Assets	592	600
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	4,131	3,946
Accumulated depreciation	(1,044)	(1,021)
Net Property, Plant and Equipment	3,087	2,925
TOTAL ASSETS	$ 4,005	$ 3,844

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

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

	September 30, 2015	December 31, 2014
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 171	$ 211
Current portion of long-term debt	—	100
Accounts payable	46	39
Accrued liabilities	63	74
Accounts payable due to associated companies	22	17
Taxes accrued	6	3
Interest accrued	16	7
Customer deposits	26	24
Other	32	42
Total Current Liabilities	382	517
DEFERRED CREDITS		
Regulatory liabilities	223	225
Deferred income tax liabilities, net	944	893
Investment tax credits	4	4
Other postretirement benefit obligations	19	21
Other	34	35
Total Deferred Credits	1,224	1,178
OTHER LONG-TERM LIABILITIES		
Long-term debt	1,171	971
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	612	537
Retained earnings	616	641
Total Equity	1,228	1,178
TOTAL LIABILITIES AND EQUITY	$ 4,005	$ 3,844

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, 2015	Nine Months Ended September 30, 2014
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 55	$ 79
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	117	93
Deferred income taxes	40	94
Changes in:		
Accounts receivable	(15)	43
Inventories	9	(9)
Regulatory assets and liabilities, net	(34)	(47)
Accounts payable and accrued liabilities	(5)	1
Income tax-related prepayments, receivables and payables	3	2
Interest accrued	9	10
Other assets and liabilities	9	1
Net Cash From Operating Activities	188	267
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(246)	(251)
Changes in restricted cash equivalents	5	(5)
Net other investing activities	1	(1)
Net Cash Used By Investing Activities	(240)	(257)
FINANCING ACTIVITIES		
Dividends paid to Parent	(80)	(20)
Capital contributions from Parent	75	130
Issuances of long-term debt	200	204
Reacquisition of long-term debt	(100)	—
Repayments of short-term debt, net	(40)	(147)
Cost of issuances	(2)	(2)
Net other financing activities	—	1
Net Cash From Financing Activities	53	166
Net Increase in Cash and Cash Equivalents	1	176
Cash and Cash Equivalents at Beginning of Period	4	2
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 5	$ 178
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash received for income taxes (includes payments from PHI for federal income taxes)	$ (5)	$ (43)

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, 2014	1,000	$ —	$ 537	$ 641	$1,178
Net Income	—	—	—	32	32
Dividends on common stock	—	—	—	(62)	(62)
BALANCE, MARCH 31, 2015	1,000	—	537	611	1,148
Net Income	—	—	—	8	8
Capital contribution from Parent	—	—	75	—	75
BALANCE, JUNE 30, 2015	1,000	—	612	619	1,231
Net Income	—	—	—	15	15
Dividends on common stock	—	—	—	(18)	(18)
BALANCE, SEPTEMBER 30, 2015	1,000	$ —	$ 612	$ 616	$1,228

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).

PHI entered into an Agreement and Plan of Merger, dated April 29, 2014, as amended and restated on July 18, 2014 (the Merger Agreement), with Exelon Corporation, a Pennsylvania corporation (Exelon), and Purple Acquisition Corp., a Delaware corporation and an indirect, wholly owned subsidiary of Exelon (Merger Sub), providing for the merger of Merger Sub with and into PHI (the Merger), with PHI surviving the Merger as an indirect, wholly owned subsidiary of Exelon. Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of common stock, par value $0.01 per share, of PHI (other than (i) shares owned by Exelon, Merger Sub or any other direct or indirect wholly owned subsidiary of Exelon and shares owned by PHI or any direct or indirect wholly owned subsidiary of PHI, and in each case not held on behalf of third parties (but not including shares held by PHI in any rabbi trust or similar arrangement in respect of any compensation plan or arrangement) and (ii) shares that are owned by stockholders who have perfected and not withdrawn a demand for appraisal rights pursuant to Delaware law), will be canceled and converted into the right to receive $27.25 in cash, without interest.

In connection with entering into the Merger Agreement, PHI entered into a Subscription Agreement, dated April 29, 2014 (the Subscription Agreement), with Exelon, pursuant to which on April 30, 2014, PHI issued to Exelon 9,000 originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share (the Preferred Stock), for a purchase price of $90 million. Exelon also committed pursuant to the Subscription Agreement to purchase 1,800 originally issued shares of Preferred Stock for a purchase price of $18 million at the end of each 90-day period following the date of the Subscription Agreement until the Merger closes or is terminated, up to a maximum of 18,000 shares of Preferred Stock for a maximum aggregate consideration of $180 million. In accordance with the Subscription Agreement, on each of July 29, 2014, October 27, 2014, January 26, 2015, April 27, 2015 and July 24, 2015, an additional 1,800 shares of Preferred Stock were issued by PHI to Exelon for a purchase price of $18 million. The holders of the Preferred Stock will be entitled to receive a cumulative, non-participating cash dividend of 0.1% per annum, payable quarterly, when, as and if declared by PHI's board of directors. The proceeds from the issuance of the Preferred Stock are not subject to restrictions and are intended to serve as a prepayment of any applicable reverse termination fee payable from Exelon to PHI. The Preferred Stock will be redeemable on the terms and in the circumstances set forth in the Merger Agreement and the Subscription Agreement.

The Merger Agreement provides for certain termination rights for each of PHI and Exelon, and further provides that, upon termination of the Merger Agreement under certain specified circumstances, PHI will be required to pay Exelon a termination fee of $259 million or reimburse Exelon for its expenses up to $40 million (which reimbursement of expenses shall reduce on a dollar for dollar basis any termination fee subsequently payable by PHI), provided, however, that if the Merger Agreement is terminated in connection with an acquisition proposal made under certain circumstances by a person who made an acquisition proposal between April 1, 2014 and the date of the Merger Agreement, the termination fee will be $293 million plus reimbursement of Exelon for its expenses up to $40 million (not subject to offset). In addition, if the Merger Agreement is terminated under certain circumstances due to the failure to obtain required regulatory approvals with respect to the Merger or the breach by Exelon of its obligations in respect of obtaining such regulatory approvals (a Regulatory Termination), PHI will be able to redeem any issued and outstanding Preferred Stock at par value, and in that case, Exelon will be required to pay all documented out-of-pocket expenses incurred by PHI in connection with the Merger Agreement or the transactions contemplated thereby, up to $40 million. If the Merger Agreement is terminated, other than for a Regulatory Termination, PHI will be required to redeem the Preferred Stock at the purchase price of $10,000 per share, plus any unpaid accrued and accumulated dividends thereupon.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (i) the approval of the Merger by the holders of a majority of the outstanding shares of common stock of PHI; (ii) the receipt of regulatory approvals required to consummate the Merger, including approvals from the Federal Energy Regulatory Commission (FERC), the Federal Communications Commission (FCC), the Delaware Public Service Commission (DPSC), the District of Columbia Public Service Commission (DCPSC), the Maryland Public Service Commission (MPSC), the New Jersey Board of Public Utilities (NJBPU) and the Virginia State Corporation Commission (VSCC); (iii) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (the HSR Act); and (iv) other customary closing conditions, including (a) the accuracy of each party's representations and warranties (subject to customary materiality qualifiers) and (b) each party's compliance with its obligations and covenants contained in the Merger Agreement (including covenants that may limit, restrict or prohibit PHI and its subsidiaries from taking specified actions during the period between the date of the Merger Agreement and the closing of the Merger or the termination of the Merger Agreement). In addition, the obligations of Exelon and Merger Sub to consummate the Merger are subject to the required regulatory approvals not imposing terms, conditions, obligations or commitments, individually or in the aggregate, that constitute a burdensome condition (as defined in the Merger Agreement). For additional discussion, see Note (7), "Regulatory Matters – Merger Approval Proceedings."

On September 23, 2014, the stockholders of PHI approved the Merger, on October 7, 2014, the VSCC approved the Merger, and on November 20, 2014, FERC approved the Merger. In addition, the transfer of control of certain communications licenses held by certain of PHI's subsidiaries has been approved by the FCC. The NJBPU approved the Merger on February 11, 2015, and on October 15, 2015, voted to extend the effectiveness of its approval until June 30, 2016. The DPSC approved the Merger on May 19, 2015.

On December 22, 2014, the waiting period under the HSR Act expired. Although the Department of Justice (DOJ) allowed the waiting period under the HSR Act to expire without taking any action with respect to the Merger, the DOJ has not advised PHI that it has concluded its investigation. The expiration of the HSR Act waiting period allows for the closing of the Merger at any time on or before December 21, 2015. If the Merger is not completed by that date the parties will be required to refile the required Notification and Report Forms with the DOJ and Federal Trade Commission (FTC), which will restart the 30-day waiting period required by the HSR Act, during which time the Merger may not be consummated, unless these agencies authorize the early termination of the waiting period. PHI and Exelon currently anticipate that they will refile with the DOJ and FTC in November 2015.

On May 15, 2015, the MPSC approved the Merger, with conditions, including conditions that modify and supplement those originally proposed. On May 18, 2015, PHI and Exelon announced that they had committed to fulfill the modified, more stringent conditions and package of customer benefits imposed by the MPSC. Multiple parties have filed petitions for judicial review of the MPSC order by the Circuit Court of Queen Anne's County, Maryland, seeking to appeal the MPSC order. PHI is vigorously contesting these appeals. The MPSC order remains in effect during the appeals process. At this time, PHI is unable to predict the outcome of the proceeding.

On August 25, 2015, the DCPSC announced at a public meeting that it had denied the merger application, and on August 27, 2015, the DCPSC issued its written order related to the Merger. On September 28, 2015, Exelon, PHI and Potomac Electric Power Company (Pepco), and certain of their respective affiliates, filed an application for reconsideration with the DCPSC requesting reconsideration of the DCPSC order related to the Merger.

On October 6, 2015, Exelon, PHI and Pepco, and certain of their respective affiliates, entered into a Nonunanimous Full Settlement Agreement and Stipulation (the DC Settlement Agreement) with the District of Columbia Government, the Office of the People's Counsel and other parties, which DC Settlement Agreement contains commitments from Exelon and PHI above those contained in their original merger application.

Also on October 6, 2015, PHI, Exelon and Merger Sub entered into a Letter Agreement (the Letter Agreement), setting forth the terms and conditions under which the parties will file with the DCPSC (a) a Motion of Joint Applicants to Reopen the Record in Formal Case No. 1119 to Allow for Consideration of the DC Settlement Agreement (the Motion to Reopen), or (b) if the Motion to Reopen is not granted, a new merger application, requesting approval of the Merger on the terms and commitments agreed to in the DC Settlement Agreement. Pursuant to the Letter Agreement, PHI and Exelon each agrees, among other things, that neither party will exercise the termination rights each may have under the Merger Agreement on or after October 29, 2015, unless: (i) the DCPSC does not, within 45 days following the date on which the DC Settlement Agreement is filed with the DCPSC (the Settlement Filing Date), set a procedural schedule which allows for a final order for approval of the Merger within 150 days after the Settlement Filing Date, (ii) the DCPSC sets a schedule for action which does not allow for a final order for approval of the Merger within 150 days after the Settlement Filing Date, (iii) the DCPSC fails to issue a final order approving the Merger and the DC Settlement Agreement as filed without condition or modification within 150 days after the Settlement Filing Date, (iv) the DCPSC issues a final order denying approval of the Merger or the DC Settlement Agreement or adds conditions or makes modifications to the DC Settlement Agreement, (v) the DC Settlement Agreement is terminated for any reason, or (vi) on or after the date that is 151 days after the Settlement Filing Date a condition to closing of the Merger has not been satisfied or waived (other than those conditions that by their nature are to be satisfied at the closing). The Letter Agreement also provides that, subject to certain conditions, Exelon may, following receipt of all regulatory approvals consistent with the DC Settlement Agreement, delay closing of the Merger for up to 30 days to engage in capital markets transactions to raise additional funds required to consummate the Merger.

On October 6, 2015, following execution of the DC Settlement Agreement and the Letter Agreement, Exelon, PHI and Pepco, and certain of their respective affiliates, filed with the DCPSC the Motion to Reopen requesting consideration of the DC Settlement Agreement and approval of the Merger on such terms and conditions set forth in the DC Settlement Agreement, without condition or modification, and to stay further proceedings on the application for reconsideration filed by the parties on September 28, 2015 and suspend the time period for reconsideration pending the DCPSC's consideration of the DC Settlement Agreement.

(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, 2014. 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, 2015, in accordance with GAAP. The year-end December 31, 2014 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, 2015 may not be indicative of DPL's results that will be realized for the full year ending December 31, 2015.

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, the calculation of 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 adequacy of the allowance for uncollectible accounts, 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 loss contingency liabilities for general litigation and auto and other 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.

Storm Restoration Costs

On June 23, 2015, DPL’s Delaware and Maryland service territories were affected by a severe storm with damaging winds and heavy rains. This storm resulted in widespread customer outages and caused damage to the electric transmission and distribution systems. Storm restoration activity commenced immediately following the storm and continued into July 2015, with the majority of the incremental storm restoration costs occurring in the second quarter of 2015.

Total incremental storm restoration costs incurred by DPL for the storm through September 30, 2015 were $4 million, with $2 million incurred for repair work and $2 million incurred as capital expenditures. Costs incurred for repair work of less than $1 million were deferred as regulatory assets to reflect the probable recovery of these costs in Maryland, and $2 million was charged to Other operation and maintenance expense. As of September 30, 2015, the total incremental storm restoration costs included $1 million of estimated costs for unbilled restoration services provided by certain outside contractors. Actual costs for these services may vary from the estimates. DPL intends to pursue recovery of these incremental storm restoration costs in its next electric distribution base rate cases.

Consolidation of Variable Interest Entities

DPL assesses its contractual arrangements with variable interest entities (VIEs) 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. See Note (15), “Variable Interest Entities,” for additional information.

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. 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 (that is, a greater than 50% chance) reduce the estimated 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 unit, an adverse change in business conditions, an adverse regulatory action, or an impairment of DPL’s long-lived assets. DPL performed its most recent annual impairment test as of November 1, 2014, and its goodwill was not impaired as described in Note (6), “Goodwill.”

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, 2015 and 2014, and $13 million and $12 million for the nine months ended September 30, 2015 and 2014, respectively.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Business Combinations (ASC 805)

In November 2014, the FASB issued new recognition and disclosure requirements related to pushdown accounting. The new recognition requirements grant an acquired entity (or its subsidiaries) the option to elect whether and when a new accounting and reporting basis (pushdown accounting) will be applied when an acquirer obtains control of the acquired entity. This election may be made by the acquired entity (or its subsidiaries) for future change-in-control events or for its most recent change-in-control event, and the acquired entity will be required to determine whether pushdown accounting will be applied in the reporting period in which the change-in-control event occurs or in a subsequent reporting period.

The new required disclosures include information that enables financial statement users to evaluate the effects of pushdown accounting. Disclosures are required to be made in the period in which pushdown accounting is applied and are expected to include both qualitative and quantitative information.

The new recognition and disclosure requirements became effective on a prospective basis on November 18, 2014.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Revenue from Contracts with Customers (ASC 606)

In May 2014, the FASB issued new recognition and disclosure requirements for revenue from contracts with customers, which supersedes the existing revenue recognition guidance. The new recognition requirements focus on when the customer obtains control of the goods or services, rather than the current risks and rewards model of recognition. The core principle of the new standard is that an entity will recognize revenue when it transfers goods or services to its customers in an amount that reflects the consideration an entity expects to be entitled to for those goods or services. The new disclosure requirements will include information intended to communicate the nature, amount, timing and any uncertainty of revenue and cash flows from applicable contracts, including any significant judgments and changes in judgments and assets recognized from the costs to obtain or fulfill a contract. Entities will generally be required to make more estimates and use more judgment under the new standard.

The new requirements will be effective for DPL beginning January 1, 2018, and may be implemented either retrospectively for all periods presented, or as a cumulative-effect adjustment as of January 1, 2018. Early adoption is permitted, but not before January 1, 2017. DPL is currently evaluating the potential impact of this new guidance on its financial statements and which implementation approach to select.

Presentation of Debt Issuance Costs (ASC 835)

In April 2015, the FASB issued new guidance for the presentation of debt issuance costs on the balance sheet. Debt issuance costs are currently required to be presented on the balance sheet as assets. However, under the new requirements, these debt issuance costs will be offset against the debt to which the costs relate. The new requirements will be effective for DPL beginning January 1, 2016, and are required to be implemented on a retrospective basis for all periods presented. Early adoption is permitted. DPL is currently evaluating the potential impact of this new guidance on its financial statements, but the impact is not expected to be material.

Business Combination (ASC 805)

In September 2015, the FASB issued new guidance on adjustments to provisional amounts recognized in a business combination, which are currently recognized on a retrospective basis. Under the new requirements, adjustments will be recognized in the reporting period in which the adjustments are determined. The effects of changes in depreciation, amortization, or other income arising from changes to the provisional amounts, if any, are included in earnings of the reporting period in which the adjustments to the provisional amounts are determined. An entity is also required to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The new requirements will be effective for DPL beginning January 1, 2016, and are required to be implemented on a prospective basis. Early adoption is permitted. DPL currently anticipates it may be affected by the new guidance if its Merger with Exelon is consummated.

(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 as of September 30, 2015. 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, 2014 indicated that goodwill was not impaired. For the nine months ended September 30, 2015, DPL concluded that there were no events or circumstances requiring it to perform an interim goodwill impairment test. DPL will perform its next annual impairment test as of November 1, 2015.

(7) REGULATORY MATTERS

Rate Proceedings

As further described in Note (1), "Organization," on April 29, 2014, PHI entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, PHI and its subsidiaries may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than pursuing the conclusion of the pending filings indicated below. To date, DPL has not requested such consent from Exelon and has not filed any new distribution base rate cases since entering into the Merger Agreement.

Bill Stabilization Adjustment

A decoupling mechanism, the bill stabilization adjustment, was approved and implemented for DPL electric service in Maryland. DPL's decoupling proposal in Delaware has not to date been adopted.

Delaware

Electric Distribution Base Rates

In March 2013, DPL submitted an application with the DPSC to increase its electric distribution base rates. The application sought approval of an annual rate increase of approximately $42 million (adjusted by DPL to approximately $39 million on September 20, 2013), based on a requested return on equity (ROE) of 10.25%. The requested rate increase sought to recover expenses associated with DPL's ongoing investments in reliability enhancement improvements and efforts to maintain safe and reliable service. In August 2014, the DPSC issued a final order in this proceeding providing for an annual increase in DPL's electric distribution base rates of approximately $15.1 million, based on an ROE of 9.70%. The new rates became effective on May 1, 2014.

In September 2014, DPL filed an appeal with the Delaware Superior Court of the DPSC's August 2014 order in this proceeding, seeking the court's review of the DPSC's decision relating to the recovery of costs associated with one component of employee compensation, certain retirement benefits and credit facility expenses. The Division of the Public Advocate filed a cross-appeal in September 2014, pertaining to the treatment of a prepaid pension expense and other postretirement benefit obligations in base rates. Under the settlement agreement related to the Merger described below in “Merger Approval Proceedings – Delaware,” the parties agreed to suspend the appeal and, if the Merger is completed, to the withdrawal of the appeal and the cross-appeal with prejudice.

Forward Looking Rate Plan

In October 2013, DPL filed a multi-year rate plan, referred to as the Forward Looking Rate Plan (FLRP). As proposed, the FLRP would provide for annual electric distribution base rate increases over a four-year period in the aggregate amount of approximately $56 million. The FLRP as proposed provides the opportunity to achieve estimated earned ROEs of 7.41% and 8.80% in years one and two, respectively, and 9.75% in both years three and four of the plan.

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

In October 2013, the DPSC opened a docket for the purpose of reviewing the details of the FLRP, but stated that it would not address the FLRP until the electric distribution base rate case discussed above was concluded. Although that rate case has been concluded, a schedule for the FLRP docket has not yet been established.

Under the Merger Agreement, DPL is permitted to pursue this matter; however, under the settlement agreement related to the Merger described below in “Merger Approval Proceedings – Delaware,” DPL agreed to withdraw the FLRP if the Merger is completed, without prejudice to the right to make future filings with the DPSC proposing alternative regulatory methodologies that could include, but are not limited to, a multi-year rate plan.

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. In August 2014, DPL made its 2014 GCR filing in which it proposed a GCR decrease of approximately 7.4%. In September 2014, the DPSC issued an order authorizing DPL to place the new rates into effect on November 1, 2014, subject to refund and pending final DPSC approval. On August 4, 2015, the DPSC issued an order approving the rates as filed.

On August 27, 2015, DPL made its 2015 GCR filing. The rates proposed in the 2015 GCR filing would result in a GCR decrease of approximately 26%, primarily reflecting lower natural gas prices. On September 22, 2015, the DPSC issued an order allowing DPL to place the new rates into effect on November 1, 2015, subject to refund and pending final DPSC approval.

Under the Merger Agreement, DPL is permitted to continue to file its required annual GCR cases in Delaware.

FERC Transmission ROE Challenges

In February 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Municipal Electric Corporation, Inc. (DEMEC), filed a joint complaint at FERC against DPL and its affiliates, Pepco and Atlantic City Electric Company (ACE), as well as Baltimore Gas and Electric Company (BGE). The complainants challenged the base ROE and certain protocols regarding the formula rate process associated with the transmission service that the 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. The 10.8% base ROE for facilities placed into service prior to 2006 receives 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 this complaint. In August 2014, FERC issued an order setting the matters in this proceeding for hearing, but holding the hearing in abeyance pending settlement discussions. The order also (i) directed that the evidence and analysis presented concerning ROE be guided by the new ROE methodology adopted by FERC in another proceeding (discussed below), and (ii) set a 15-month refund period that commenced on February 27, 2013, should a refund result from this proceeding. After settlement discussions among the parties in this matter reached an impasse, the settlement judge, in November 2014, issued an order terminating the settlement discussions and referring the matter to a presiding administrative law judge.

In June 2014, FERC issued an order in a proceeding in which DPL was not involved, in which it adopted a new ROE methodology for electric utilities. This new methodology replaces the existing one-step discounted cash flow analysis (which incorporates only short-term growth rates) traditionally used to derive ROE for electric utilities with the two-step discounted cash flow analysis (which incorporates both short-term and long-term measures of growth) used for natural gas and oil pipelines. As a result of the August 2014 FERC order discussed in the preceding paragraph, DPL applied an estimated ROE based on the two-step methodology announced by FERC for the 15-month period over which its transmission revenues would be subject to refund as a result of the challenge, and recorded estimated reserves for the entire 15-month refund period in the second quarter of 2014.

On December 8, 2014, the parties that filed the February 2013 complaint filed a second complaint against Pepco, DPL, ACE, as well as BGE, regarding the base transmission ROE, seeking a reduction from 10.8% to 8.8%. By order issued on February 9, 2015, FERC established a hearing on the second complaint and established a second 15-month refund period that commenced on December 8, 2014. Consistent with the prior challenge, DPL applied an estimated refund based on the two-step methodology described above, and in the fourth quarter of 2014 and in the first, second and third quarters of 2015 established reserves for the estimated refund based on the effective date of the second refund period of December 8, 2014. On February 20, 2015, the chief judge issued an order consolidating the two complaint proceedings and established an initial decision issuance deadline of February 29, 2016. On March 2, 2015, the presiding administrative law judge issued an order establishing a procedural schedule for the consolidated proceedings that provides for the hearing to commence on October 20, 2015.

Also during the third quarter of 2015, DPL further evaluated the reserves established for each of the two refund periods and, based on an updated assessment of market conditions, developments in other cases before FERC, litigation risk and other factors, increased its reserves to reflect management's best estimate of the refund that is expected to result from these consolidated proceedings. As of September 30, 2015, DPL's reserves for both of the refund periods totaled $9 million. A settlement entered into by the parties regarding the protocols (but not the ROE) raised in the February 2013 complaint was submitted to FERC on July 31, 2015 and is awaiting FERC approval.

To the extent that the final ROE established in these consolidated proceedings is lower than the ROE used to record the estimated reserves with respect to the February 2013 and the December 2014 complaints, each ten basis point reduction in the ROE would result in an increase in required reserves and a reduction of DPL's operating income of $1.0 million.

MPSC New Generation Contract Requirement

In April 2012, the MPSC issued an order that requires Maryland electric distribution companies (EDCs) Pepco, DPL and BGE (collectively, the Contract EDCs) to negotiate and enter into a contract with the winning bidder of a competitive bidding process to build one new power plant in the range of 650 to 700 megawatts (MWs) beginning in 2015, in amounts proportional to their relative standard offer service (SOS) loads. Under the terms of the order, the winning bidder was to construct a 661 MW natural gas-fired combined cycle generation plant in Waldorf, Maryland, with an originally expected commercial operation date of June 1, 2015 (which is now deferred pending the outcome of the proceedings discussed below), and each of the Contract EDCs will recover its costs associated with the contract through surcharges on its respective SOS customers.

In response to a complaint filed by a group of generating companies in the PJM Interconnection, LLC region, in September 2013, the U.S. District Court for the District of Maryland (the Federal District Court) 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, in October 2013, in response to appeals filed by the Contract EDCs and other parties, the Maryland Circuit Court for Baltimore City (the Maryland Circuit Court) upheld the MPSC's orders requiring the Contract EDCs to enter into the contracts.

In October 2013, the Federal District Court issued an order ruling that the contracts are illegal and unenforceable. The Contract EDCs, the Maryland Office of People's Counsel and one generating company have appealed the Maryland Circuit Court's decision to the Maryland Court of Special Appeals. In addition, in November 2013 both the winning bidder and the MPSC appealed the Federal District Court decision to the U.S. Court of Appeals for the Fourth Circuit, which affirmed the decision. In November 2014, the winning bidder and the MPSC each petitioned the U.S. Supreme Court to consider hearing an appeal of the Fourth Circuit decision and, on October 19, 2015, the U.S. Supreme Court agreed to review that decision.

Assuming the contracts, as currently written, become effective following the satisfaction of all relevant conditions, including the completion of the proceedings discussed above, DPL continues to believe that it may be required to record its proportional share of the contracts as derivative instruments at fair value and record related regulatory assets of approximately the same amount because it would be entitled to recover any payments under the contracts from SOS customers. DPL has 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.

Merger Approval Proceedings

Delaware

On June 18, 2014, Exelon, PHI and DPL, and certain of their respective affiliates, filed an application with the DPSC seeking approval of the Merger. Delaware law requires the DPSC to approve the Merger when it determines that the transaction is in accordance with law, for a proper purpose, and is consistent with the public interest. The DPSC must further find that the successor will continue to provide safe and reliable service, will not terminate or impair existing collective bargaining agreements and will engage in good faith bargaining with organized labor. On February 13, 2015, Exelon, DPL, the DPSC staff, the Division of the Public Advocate and certain other parties filed a settlement agreement with the DPSC, which was amended in April 2015. The DPSC approved the amended settlement agreement at its meeting held on May 19, 2015, memorializing this decision by written order issued on June 2, 2015. The specific grounds for the DPSC's approval of the Merger, as well as the specific conditions, will be included in an order to be issued by the DPSC after the Merger closes.

Maryland

On August 19, 2014, Exelon, PHI, Pepco, DPL and certain of their respective affiliates, filed an application with the MPSC seeking approval of the Merger. Maryland law requires the MPSC to approve a merger subject to its review if it finds that the merger is consistent with the public interest, convenience and necessity, including its benefits to and impact on consumers. Evidentiary hearings were held beginning on January 26, 2015. On March 10, 2015, Exelon, PHI, Pepco, DPL and certain of their respective affiliates, filed with the MPSC a settlement agreement entered into with one of the stakeholder groups participating in the MPSC approval proceeding. On March 16, 2015, Exelon, PHI, Pepco, DPL and certain of their respective affiliates, filed with the MPSC a settlement agreement entered into with Montgomery and Prince George's Counties in Maryland, and a number of other parties.

On May 15, 2015, the MPSC approved the Merger, with conditions, including conditions that modify and supplement those originally proposed. On May 18, 2015, Pepco Holdings and Exelon announced that they had completed their review of the MPSC's order approving the Merger and have committed to fulfill the modified, more stringent conditions and package of customer benefits imposed by the MPSC.

Multiple parties have filed petitions for judicial review of the MPSC order by the Circuit Court of Queen Anne's County, Maryland, seeking to appeal the MPSC order. In connection with these proceedings, the Maryland Office of People's Counsel and several other parties to the Merger proceedings filed motions in the Circuit Court for Queen Anne's County, Maryland, requesting a stay of the MPSC order. On August 7, 2015, the Circuit Court for Queen Anne's County denied the motions for stay. Exelon and Pepco Holdings are vigorously contesting these appeals of the MPSC order. The MPSC order remains in effect during the appeals process. At this time, PHI is unable to predict the outcome of the proceeding.

Virginia

On June 3, 2014, Exelon, PHI, Pepco and DPL, and certain of their respective affiliates, filed an application with the VSCC seeking approval of the Merger. Virginia law provides that, if the VSCC determines, with or without hearing, that adequate service to the public at just and reasonable rates will not be impaired or jeopardized by granting the application for approval, then the VSCC shall approve a merger with such conditions that the VSCC deems to be appropriate in order to satisfy this standard. On October 7, 2014, the VSCC issued an order approving the Merger.

Federal Energy Regulatory Commission

On May 30, 2014, Exelon, PHI, Pepco, DPL and ACE, and certain of their respective affiliates, submitted to FERC a Joint Application for Authorization of Disposition of Jurisdictional Assets and Merger under Section 203 of the Federal Power Act. Under that section, FERC shall approve a merger if it finds that the proposed transaction will be consistent with the public interest. On November 20, 2014, FERC issued an order approving the Merger.

(8) PENSION AND OTHER POSTRETIREMENT BENEFITS

DPL accounts for its participation in PHI's single-employer plans, PHI's noncontributory retirement plan (the PHI Retirement Plan) and its other postretirement benefits plan, the Pepco Holdings, Inc. Welfare Plan for Retirees (the OPEB Plan), as participation in multiemployer plans. PHI's pension and other postretirement net periodic benefit cost for the three months ended September 30, 2015 and 2014, before intercompany allocations from the PHI Service Company, were $25 million and $16 million, respectively. DPL's allocated share was $3 million and $1 million for the three months ended September 30, 2015 and 2014, respectively. PHI's pension and other postretirement net periodic benefit cost for the nine months ended September 30, 2015 and 2014, before intercompany allocations from the PHI Service Company, were $73 million and $44 million, respectively. DPL's allocated share was $11 million and $5 million for the nine months ended September 30, 2015 and 2014, respectively.

For the nine months ended September 30, 2015 and 2014, DPL made no discretionary tax-deductible contributions to the PHI Retirement Plan.

(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, 2013, as permitted under the existing terms of the credit agreement, a request by PHI, Pepco, DPL and ACE to extend the credit facility termination date to August 1, 2018 was approved. All of the terms and conditions as well as pricing remained 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, $200 million, $250 million and $300 million for PHI, Pepco, DPL and ACE, respectively. 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, 2015.

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.

At each of September 30, 2015 and December 31, 2014, 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 $413 million. 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.

Credit Facility Amendment

On May 20, 2014, PHI, Pepco, DPL and ACE entered into an amendment of and consent with respect to the credit agreement (the Consent). PHI was required to obtain the consent of certain of the lenders under the credit facility in order to permit the consummation of the Merger. Pursuant to the Consent, certain of the lenders consented to the consummation of the Merger and the subsequent conversion of PHI from a Delaware corporation to a Delaware limited liability company, provided that the Merger and subsequent conversion are consummated on or before October 29, 2015. In addition, the Consent amends the definition of "Change in Control" in the credit agreement to mean, following consummation of the Merger, an event or series of events by which Exelon no longer owns, directly or indirectly, 100% of the outstanding shares of voting stock of Pepco Holdings. PHI has requested an extension of the Consent to allow for completion of the Merger by June 30, 2016.

Commercial Paper

DPL maintains an on-going commercial paper program to address its short-term liquidity needs. As of September 30, 2015, the maximum capacity available under the program was $500 million, subject to available borrowing capacity under the credit facility.

DPL had $66 million of commercial paper outstanding at September 30, 2015. The weighted average interest rate for commercial paper issued by DPL during the nine months ended September 30, 2015 was 0.46% and the weighted average maturity of all commercial paper issued by DPL during the nine months ended September 30, 2015 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,			
	2015		2014		2015		2014	
	(millions of dollars)							
Income tax at Federal statutory rate	$ 8	35.0%	$ 13	35.0%	$ 32	35.0%	$ 46	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	1	4.2%	2	5.6%	5	5.6%	7	5.4%
Depreciation	(1)	(4.2)%	(1)	(2.8)%	(2)	(2.2)%	(1)	(0.8)%
Other, net	1	2.5%	(1)	(1.7)%	—	0.5%	(1)	(0.4)%
Income tax expense	$ 9	37.5%	$ 13	36.1%	$ 35	38.9%	$ 51	39.2%

(11) DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

DPL uses derivative instruments in the form of futures 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. 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, 2015 and December 31, 2014:

	As of September 30, 2015				
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	$ —

	As of December 31, 2014				
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	$ —

All derivative liabilities available to be offset under master netting arrangements were netted as of September 30, 2015 and December 31, 2014. The amount of cash collateral that was offset against these derivative positions is as follows:

	September 30, 2015	December 31, 2014
	(millions of dollars)	
Cash collateral pledged to counterparties with the right to reclaim (a)	$ 1	$ 4

(a) Includes cash deposits on commodity brokerage accounts.

As of September 30, 2015 and December 31, 2014, 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 has 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 fair value recorded in income. In addition, in accordance with FASB guidance on regulated operations, regulatory liabilities or regulatory assets of the same amount 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. The following table shows the net unrealized and net realized derivative gains and losses arising during the period associated with these derivatives that were recognized in the statements of income (through Purchased energy and Gas purchased expense) and that were also deferred as Regulatory liabilities and Regulatory assets, respectively, for the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
		(millions of dollars)		
Net unrealized (loss) gain arising during the period	$ (1)	$ (1)	$ (2)	$ 1
Net realized (loss) gain recognized during the period	(1)	—	(5)	3

As of September 30, 2015 and December 31, 2014, the quantities and positions of DPL's net outstanding natural gas commodity forward contracts that did not qualify for hedge accounting were:

	September 30, 2015		December 31, 2014	
Commodity	**Quantity**	**Net Position**	**Quantity**	**Net Position**
Natural gas (One Million British Thermal Units)	3,760,000	Long	3,892,500	Long

(12) FAIR VALUE DISCLOSURES

Financial Instruments Measured at Fair Value on a Recurring Basis

DPL applies FASB guidance on fair value measurement (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, 2015 and December 31, 2014. 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, 2015			
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				
Derivative instruments (b)				
Natural gas (c)	$ 1	$ 1	$ —	$ —
Executive deferred compensation plan liabilities				
Life insurance contracts	1	—	1	—
Total	$ 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, 2015.
(b) The fair value of derivative liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

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, 2014			
		(millions of dollars)		
ASSETS				
Restricted cash equivalents				
Treasury funds	$ 5	$ 5	$ —	$ —
Executive deferred compensation plan assets				
Money market funds	1	1	—	—
Life insurance contracts	1	—	—	1
Total	$ 7	$ 6	$ —	$ 1
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 4	$ 4	$ —	$ —
Executive deferred compensation plan liabilities				
Life insurance contracts	1	—	1	—
Total	$ 5	$ 4	$ 1	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2014.
(b) The fair value of derivative liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents natural gas futures 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 Intercontinental Exchange.

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.

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, 2015 and 2014 are shown below:

	Life Insurance Contracts	
	Nine Months Ended September 30,	
	2015	2014
	(millions of dollars)	
Balance as of January 1	$ 1	$ 1
Total gains (losses) (realized and unrealized):		
Included in income	—	—
Included in accumulated other comprehensive loss	—	—
Included in regulatory liabilities	—	—
Purchases	—	—
Issuances	—	—
Settlements	(1)	—
Transfers in (out) of Level 3	—	—
Balance as of September 30	$ —	$ 1

Other Financial Instruments

The estimated fair values of DPL’s Long-term debt instruments that are measured at amortized cost in DPL’s financial statements and the associated levels of the estimates within the fair value hierarchy as of September 30, 2015 and December 31, 2014 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, 2015			
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)	$1,190	$ —	$ 1,086	$ 104

(a) The carrying amount for Long-term debt was $1,171 million as of September 30, 2015.

Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Fair Value Measurements at December 31, 2014			
		(millions of dollars)		
LIABILITIES				
Debt instruments				
Long-term debt (a)	$1,123	$ —	$ 1,016	$ 107

(a) The carrying amount for Long-term debt was $1,071 million as of December 31, 2014.

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

(13) COMMITMENTS AND CONTINGENCIES

General Litigation

From time to time, DPL is named as a defendant in litigation, usually relating to general liability or auto liability claims that resulted in personal injury or property damage to third parties. DPL is self-insured against such claims up to a certain self-insured retention amount and maintains insurance coverage against such claims at higher levels, to the extent deemed prudent by management. In addition, DPL's contracts with its vendors generally require the vendors to name DPL as an additional insured for the amount at least equal to DPL's self-insured retention. Further, DPL's contracts with its vendors require the vendors to indemnify DPL for various acts and activities that may give rise to claims against DPL. Loss contingency liabilities for both asserted and unasserted claims are recognized if it is probable that a loss will result from such a claim and if the amounts of the losses can be reasonably estimated. Although the outcome of the claims and proceedings cannot be predicted with any certainty, management believes that there are no existing claims or proceedings that are likely to have a material adverse effect on DPL's financial condition, results of operations or cash flows. At September 30, 2015, DPL had recorded estimated loss contingency liabilities for general litigation totaling approximately $2 million.

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, 2015 are summarized as follows:

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

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 the first quarter of 2013, the National Oceanic and Atmospheric Administration (NOAA) contacted DPL on behalf of itself and other federal and state trustees to request that 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 Cottman Avenue Superfund Site located in Philadelphia, Pennsylvania. DPL executed a tolling agreement, which has been extended to March 15, 2016, and will continue settlement discussions with the NOAA, the trustees and other potentially responsible parties.

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

Virginia Department of Environmental Quality Notice of Violation

On February 3, 2015, the Virginia Department of Environmental Quality (VDEQ) issued a notice of violation (NOV) to DPL in connection with alleged violations of state water control laws and regulations associated with recent construction activities undertaken to replace certain transmission facilities. The NOV informed DPL of information on which VDEQ may rely to institute an administrative or judicial enforcement action, requested a meeting, and stated that DPL may be asked to enter into a consent order to formalize a plan and schedule of corrective action and settle any outstanding issues regarding the matter including the assessment of civil charges. At a February 20, 2015 meeting, VDEQ confirmed that the NOV would be resolved through a consent order, which will require the payment of a penalty, but did not specify the potential penalty amount. DPL will pursue recovery of the restoration costs for this matter from the contractor responsible for the vegetation management activities that gave rise to the alleged violations. PHI and DPL do not believe that the remediation costs to resolve this matter will have a material adverse effect on their respective financial condition, results of operations or cash flows.

(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, 2015 and 2014 were approximately $44 million and $42 million, respectively. PHI Service Company costs directly charged or allocated to DPL for the nine months ended September 30, 2015 and 2014 were approximately $136 million and $121 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, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	(millions of dollars)			
Intercompany lease transactions (a)	$ 1	$ 1	$ 3	$ 3

(a) Included in Electric revenue.

As of September 30, 2015 and December 31, 2014, DPL had the following balances on its balance sheets due to related parties:

	September 30, 2015	December 31, 2014
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (20)	$ (18)
Other	(2)	1
Total	$ (22)	$ (17)

(a) Included in Accounts payable due to associated companies.

(15) VARIABLE INTEREST ENTITIES

DPL is required to consolidate a VIE in accordance with FASB ASC 810 if DPL is the primary beneficiary of the VIE. The primary beneficiary of a VIE is typically the entity with both the power to direct activities most significantly impacting economic performance of the VIE and the obligation to absorb losses or receive benefits of the VIE that could potentially be significant to the VIE. DPL performed a qualitative analysis to determine whether a variable interest provided a controlling financial interest in any of the VIEs in which DPL has an interest at September 30, 2015, as described below.

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, 2015, DPL is a party to three land-based wind power purchase agreements (PPAs) in the aggregate amount of 128 MWs, one solar power PPA with a 10 MW facility, and a PPA with the Delaware Sustainable Energy Utility (DSEU) to purchase solar renewable energy credits (SRECs). Each of the facilities associated with these PPAs is operational, except for the facilities associated with the PPA with the DSEU, which are expected to be operational within one year. DPL is obligated to purchase energy and RECs in amounts generated and delivered by the wind facilities and SRECs from the solar facility and the DSEU, up to certain amounts (as set forth below) at rates that are primarily fixed under the respective agreements. DPL has concluded that while VIEs exist under these contracts, consolidation is not required under FASB ASC 810 as DPL is not the primary beneficiary. DPL has not provided financial or other support under these arrangements that it was not previously contractually required to provide during the periods presented, and DPL does not have any intention to provide such additional support.

Because DPL has no equity or debt interest in these renewable energy transactions, the maximum exposure to loss relates primarily to any above-market costs incurred for power, RECs or SRECs. Due to unpredictability in the amount of MWs ultimately purchased under the agreements for purchased renewable energy, RECs and SRECs, DPL is unable to quantify the maximum exposure to loss, however, the power purchase, REC and SREC costs are recoverable from DPL's customers through regulated rates.

Wind PPAs

DPL is obligated to purchase energy and RECs from one of the wind facilities through 2024 in amounts not to exceed 50 MWs, from a second wind facility through 2031 in amounts not to exceed 40 MWs, and from a third wind facility through 2031 in amounts not to exceed 38 MWs. DPL's aggregate purchases under the three wind PPAs totaled $4 million and $5 million for the three months ended September 30, 2015 and 2014, respectively. DPL's aggregate purchases under the three wind PPAs totaled $20 million and $21 million for the nine months ended September 30, 2015 and 2014, respectively.

Solar PPAs

The term of the PPA with the solar facility is through 2030 and DPL is obligated to purchase SRECs in an amount up to 70 percent of the energy output at a fixed price. The DSEU may enter into 20-year contracts with solar facilities to purchase SRECs for resale to DPL. Under the PPA with the DSEU, at September 30, 2015 and 2014, DPL was obligated to purchase SRECs in amounts not to exceed 28 MWs and 19 MWs, respectively, at annually determined auction rates. DPL's purchases under these solar agreements were $2 million and $1 million for the three months ended September 30, 2015 and 2014, respectively. DPL's purchases under these solar agreements were $4 million and $3 million for the nine months ended September 30, 2015 and 2014.

Fuel Cell Facilities

On October 18, 2011, the 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 acts solely as an agent to collect payments in advance from its distribution customers and remit them to the qualified fuel cell provider for each MW hour of energy produced by the fuel cell facilities through 2033. The RPS provides for a reduction in DPL's REC requirements based upon the actual energy output of the facilities. DPL has concluded that while a VIE exists as a result of this relationship, consolidation is not required under FASB ASC 810 as DPL is not the primary beneficiary. For the three months ended September 30, 2015 and 2014, 56,388 and 56,335 megawatt hours, respectively, were produced from fuel cell facilities placed in service under the tariff. For the nine months ended September 30, 2015 and 2014, 170,028 and 165,878 megawatt hours, respectively, were produced from fuel cell facilities placed in service under the tariff. DPL billed $9 million and $8 million to distribution customers for the three months ended September 30, 2015 and 2014, respectively. DPL billed $28 million and $26 million to distribution customers for each of the nine months ended September 30, 2015 and 2014, respectively.

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	**2014**	**2015**	**2014**
	(millions of dollars)			
Operating Revenue	$ 387	$ 347	$ 1,006	$ 940
Operating Expenses				
Purchased energy	214	188	535	504
Other operation and maintenance	72	65	209	178
Depreciation and amortization	49	42	135	117
Other taxes	1	1	3	3
Deferred electric service costs	13	(1)	34	30
Total Operating Expenses	349	295	916	832
Operating Income	38	52	90	108
Other Income (Expenses)				
Interest expense	(17)	(16)	(49)	(47)
Other income	—	1	3	2
Total Other Expenses	(17)	(15)	(46)	(45)
Income Before Income Tax Expense	21	37	44	63
Income Tax Expense	7	14	16	24
Net Income	$ 14	$ 23	$ 28	$ 39

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

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2015	December 31, 2014
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 4	$ 2
Restricted cash equivalents	15	10
Accounts receivable, less allowance for uncollectible accounts of $17 million and $9 million, respectively	235	167
Inventories	26	23
Income taxes and related accrued interest receivable	151	151
Prepaid expenses and other	21	13
Total Current Assets	452	366
OTHER ASSETS		
Regulatory assets	340	427
Prepaid pension expense	86	96
Income taxes and related accrued interest receivable	34	34
Restricted cash equivalents	15	14
Other	10	12
Total Other Assets	485	583
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	3,226	3,073
Accumulated depreciation	(758)	(760)
Net Property, Plant and Equipment	2,468	2,313
TOTAL ASSETS	$ 3,405	$ 3,262

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

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2015	December 31, 2014
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 225	$ 127
Current portion of long-term debt	48	59
Accounts payable	30	20
Accrued liabilities	125	103
Accounts payable due to associated companies	15	15
Taxes accrued	11	1
Interest accrued	18	13
Customer deposits	24	21
Other	20	22
Total Current Liabilities	516	381
DEFERRED CREDITS		
Regulatory liabilities	28	14
Deferred income tax liabilities, net	877	865
Investment tax credits	5	5
Other postretirement benefit obligations	35	36
Liabilities and accrued interest related to uncertain tax positions	2	—
Other	16	16
Total Deferred Credits	963	936
OTHER LONG-TERM LIABILITIES		
Long-term debt	886	888
Transition Bonds issued by ACE Funding	138	171
Total Other Long-Term Liabilities	1,024	1,059
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
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	651
Retained earnings	225	209
Total Equity	902	886
TOTAL LIABILITIES AND EQUITY	$ 3,405	$ 3,262

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,	
	2015	2014
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 28	$ 39
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	135	117
Deferred income taxes	7	28
Changes in:		
Accounts receivable	(68)	(10)
Inventories	(3)	2
Prepaid expenses	(7)	(15)
Regulatory assets and liabilities, net	26	26
Accounts payable and accrued liabilities	33	11
Income tax-related prepayments, receivables and payables	13	(1)
Other assets and liabilities	14	18
Net Cash From Operating Activities	178	215
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(212)	(158)
Department of Energy capital reimbursement awards received	—	1
Net other investing activities	(4)	(3)
Net Cash Used By Investing Activities	(216)	(160)
FINANCING ACTIVITIES		
Dividends paid to Parent	(12)	(26)
Issuances of long-term debt	—	150
Reacquisitions of long-term debt	(46)	(36)
Issuances (repayments) of short-term debt, net	98	(39)
Repayment of term loan	—	(100)
Net other financing activities	—	(1)
Net Cash From (Used by) Financing Activities	40	(52)
Net Increase in Cash and Cash Equivalents	2	3
Cash and Cash Equivalents at Beginning of Period	2	3
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 4	$ 6
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash received for income taxes (includes payments from PHI for federal income taxes)	$ —	$ (3)

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, 2014	8,546,017	$ 26	$ 651	$ 209	$886
Net Income	—	—	—	4	4
Dividends on common stock	—	—	—	(12)	(12)
BALANCE, MARCH 31, 2015	8,546,017	26	651	201	878
Net Income	—	—	—	10	10
BALANCE, JUNE 30, 2015	8,546,017	26	651	211	888
Net Income	—	—	—	14	14
BALANCE, SEPTEMBER 30, 2015	8,546,017	$ 26	$ 651	$ 225	$902

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).

PHI entered into an Agreement and Plan of Merger, dated April 29, 2014, as amended and restated on July 18, 2014 (the Merger Agreement), with Exelon Corporation, a Pennsylvania corporation (Exelon), and Purple Acquisition Corp., a Delaware corporation and an indirect, wholly owned subsidiary of Exelon (Merger Sub), providing for the merger of Merger Sub with and into PHI (the Merger), with PHI surviving the Merger as an indirect, wholly owned subsidiary of Exelon. Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of common stock, par value $0.01 per share, of PHI (other than (i) shares owned by Exelon, Merger Sub or any other direct or indirect wholly owned subsidiary of Exelon and shares owned by PHI or any direct or indirect wholly owned subsidiary of PHI, and in each case not held on behalf of third parties (but not including shares held by PHI in any rabbi trust or similar arrangement in respect of any compensation plan or arrangement) and (ii) shares that are owned by stockholders who have perfected and not withdrawn a demand for appraisal rights pursuant to Delaware law), will be canceled and converted into the right to receive $27.25 in cash, without interest.

In connection with entering into the Merger Agreement, PHI entered into a Subscription Agreement, dated April 29, 2014 (the Subscription Agreement), with Exelon, pursuant to which on April 30, 2014, PHI issued to Exelon 9,000 originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share (the Preferred Stock), for a purchase price of $90 million. Exelon also committed pursuant to the Subscription Agreement to purchase 1,800 originally issued shares of Preferred Stock for a purchase price of $18 million at the end of each 90-day period following the date of the Subscription Agreement until the Merger closes or is terminated, up to a maximum of 18,000 shares of Preferred Stock for a maximum aggregate consideration of $180 million. In accordance with the Subscription Agreement, on each of July 29, 2014, October 27, 2014, January 26, 2015, April 27, 2015 and July 24, 2015, an additional 1,800 shares of Preferred Stock were issued by PHI to Exelon for a purchase price of $18 million. The holders of the Preferred Stock will be entitled to receive a cumulative, non-participating cash dividend of 0.1% per annum, payable quarterly, when, as and if declared by PHI’s board of directors. The proceeds from the issuance of the Preferred Stock are not subject to restrictions and are intended to serve as a prepayment of any applicable reverse termination fee payable from Exelon to PHI. The Preferred Stock will be redeemable on the terms and in the circumstances set forth in the Merger Agreement and the Subscription Agreement.

The Merger Agreement provides for certain termination rights for each of PHI and Exelon, and further provides that, upon termination of the Merger Agreement under certain specified circumstances, PHI will be required to pay Exelon a termination fee of $259 million or reimburse Exelon for its expenses up to $40 million (which reimbursement of expenses shall reduce on a dollar for dollar basis any termination fee subsequently payable by PHI), provided, however, that if the Merger Agreement is terminated in connection with an acquisition proposal made under certain circumstances by a person who made an acquisition proposal between April 1, 2014 and the date of the Merger Agreement, the termination fee will be $293 million plus reimbursement of Exelon for its expenses up to $40 million (not subject to offset). In addition, if the Merger Agreement is terminated under certain circumstances due to the failure to obtain required regulatory approvals with respect to the Merger or the breach by Exelon of its obligations in respect of obtaining such regulatory approvals (a Regulatory Termination), PHI will be able to redeem any issued and outstanding Preferred Stock at par value, and in that case, Exelon will be required to pay all documented out-of-pocket expenses incurred by PHI in connection with the Merger Agreement or the transactions contemplated thereby, up to $40 million. If the Merger Agreement is terminated, other than for a Regulatory Termination, PHI will be required to redeem the Preferred Stock at the purchase price of $10,000 per share, plus any unpaid accrued and accumulated dividends thereupon.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (i) the approval of the Merger by the holders of a majority of the outstanding shares of common stock of PHI; (ii) the receipt of regulatory approvals required to consummate the Merger, including approvals from the Federal Energy Regulatory Commission (FERC), the Federal Communications Commission (FCC), the Delaware Public Service Commission (DPSC), the District of Columbia Public Service Commission (DCPSC), the Maryland Public Service Commission (MPSC), the New Jersey Board of Public Utilities (NJBPU) and the Virginia State Corporation Commission (VSCC); (iii) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (the HSR Act); and (iv) other customary closing conditions, including (a) the accuracy of each party's representations and warranties (subject to customary materiality qualifiers) and (b) each party's compliance with its obligations and covenants contained in the Merger Agreement (including covenants that may limit, restrict or prohibit PHI and its subsidiaries from taking specified actions during the period between the date of the Merger Agreement and the closing of the Merger or the termination of the Merger Agreement). In addition, the obligations of Exelon and Merger Sub to consummate the Merger are subject to the required regulatory approvals not imposing terms, conditions, obligations or commitments, individually or in the aggregate, that constitute a burdensome condition (as defined in the Merger Agreement). For additional discussion, see Note (6), "Regulatory Matters – Merger Approval Proceedings."

On September 23, 2014, the stockholders of PHI approved the Merger, on October 7, 2014, the VSCC approved the Merger, and on November 20, 2014, FERC approved the Merger. In addition, the transfer of control of certain communications licenses held by certain of PHI's subsidiaries has been approved by the FCC. The NJBPU approved the Merger on February 11, 2015, and on October 15, 2015, voted to extend the effectiveness of its approval until June 30, 2016. The DPSC approved the Merger on May 19, 2015.

On December 22, 2014, the waiting period under the HSR Act expired. Although the Department of Justice (DOJ) allowed the waiting period under the HSR Act to expire without taking any action with respect to the Merger, the DOJ has not advised PHI that it has concluded its investigation. The expiration of the HSR Act waiting period allows for the closing of the Merger at any time on or before December 21, 2015. If the Merger is not completed by that date the parties will be required to refile the required Notification and Report Forms with the DOJ and Federal Trade Commission (FTC), which will restart the 30-day waiting period required by the HSR Act, during which time the Merger may not be consummated, unless these agencies authorize the early termination of the waiting period. PHI and Exelon currently anticipate that they will refile with the DOJ and FTC in November 2015.

On May 15, 2015, the MPSC approved the Merger, with conditions, including conditions that modify and supplement those originally proposed. On May 18, 2015, PHI and Exelon announced that they had committed to fulfill the modified, more stringent conditions and package of customer benefits imposed by the MPSC. Multiple parties have filed petitions for judicial review of the MPSC order by the Circuit Court of Queen Anne's County, Maryland, seeking to appeal the MPSC order. PHI is vigorously contesting these appeals. The MPSC order remains in effect during the appeals process. At this time, PHI is unable to predict the outcome of the proceeding.

On August 25, 2015, the DCPSC announced at a public meeting that it had denied the merger application, and on August 27, 2015, the DCPSC issued its written order related to the Merger. On September 28, 2015, Exelon, PHI and Potomac Electric Power Company (Pepco), and certain of their respective affiliates, filed an application for reconsideration with the DCPSC requesting reconsideration of the DCPSC order related to the Merger.

On October 6, 2015, Exelon, PHI and Pepco, and certain of their respective affiliates, entered into a Nonunanimous Full Settlement Agreement and Stipulation (the DC Settlement Agreement) with the District of Columbia Government, the Office of the People's Counsel and other parties, which DC Settlement Agreement contains commitments from Exelon and PHI above those contained in their original merger application.

Also on October 6, 2015, PHI, Exelon and Merger Sub entered into a Letter Agreement (the Letter Agreement), setting forth the terms and conditions under which the parties will file with the DCPSC (a) a Motion of Joint Applicants to Reopen the Record in Formal Case No. 1119 to Allow for Consideration of the DC Settlement Agreement (the Motion to Reopen), or (b) if the Motion to Reopen is not granted, a new merger application, requesting approval of the Merger on the terms and commitments agreed to in the DC Settlement Agreement. Pursuant to the Letter Agreement, PHI and Exelon each agrees, among other things, that neither party will exercise the termination rights each may have under the Merger Agreement on or after October 29, 2015, unless: (i) the DCPSC does not, within 45 days following the date on which the DC Settlement Agreement is filed with the DCPSC (the Settlement Filing Date), set a procedural schedule which allows for a final order for approval of the Merger within 150 days after the Settlement Filing Date, (ii) the DCPSC sets a schedule for action which does not allow for a final order for approval of the Merger within 150 days after the Settlement Filing Date, (iii) the DCPSC fails to issue a final order approving the Merger and the DC Settlement Agreement as filed without condition or modification within 150 days after the Settlement Filing Date, (iv) the DCPSC issues a final order denying approval of the Merger or the DC Settlement Agreement or adds conditions or makes modifications to the DC Settlement Agreement, (v) the DC Settlement Agreement is terminated for any reason, or (vi) on or after the date that is 151 days after the Settlement Filing Date a condition to closing of the Merger has not been satisfied or waived (other than those conditions that by their nature are to be satisfied at the closing). The Letter Agreement also provides that, subject to certain conditions, Exelon may, following receipt of all regulatory approvals consistent with the DC Settlement Agreement, delay closing of the Merger for up to 30 days to engage in capital markets transactions to raise additional funds required to consummate the Merger.

On October 6, 2015, following execution of the DC Settlement Agreement and the Letter Agreement, Exelon, PHI and Pepco, and certain of their respective affiliates, filed with the DCPSC the Motion to Reopen requesting consideration of the DC Settlement Agreement and approval of the Merger on such terms and conditions set forth in the DC Settlement Agreement, without condition or modification, and to stay further proceedings on the application for reconsideration filed by the parties on September 28, 2015 and suspend the time period for reconsideration pending the DCPSC's consideration of the DC Settlement Agreement.

(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, 2014. 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, 2015, in accordance with GAAP. The year-end December 31, 2014 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, 2015 may not be indicative of ACE's results that will be realized for the full year ending December 31, 2015.

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, the calculation of 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 adequacy of the allowance for uncollectible accounts, 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 loss contingency liabilities for general litigation and auto and other 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.

Storm Restoration Costs

On June 23, 2015, ACE's service territory was affected by a severe storm with damaging winds and heavy rains. This storm resulted in widespread customer outages and caused damage to the electric transmission and distribution systems. Storm restoration activity commenced immediately following the storm and continued into July 2015, with the majority of the incremental storm restoration costs occurring in the second quarter of 2015.

Total incremental storm restoration costs incurred by ACE for the storm through September 30, 2015 were $35 million, with $13 million incurred for repair work and $22 million incurred as capital expenditures. Costs incurred for repair work of $13 million were deferred as regulatory assets to reflect the probable recovery of these costs in New Jersey. As of September 30, 2015, the total incremental storm restoration costs included $9 million of estimated costs for unbilled restoration services provided by certain outside contractors. Actual costs for these services may vary from the estimates. ACE intends to pursue recovery of these incremental storm restoration costs in its next electric distribution base rate case.

Consolidation of Variable Interest Entities

ACE assesses its contractual arrangements with variable interest entities (VIEs) 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. See Note (13), "Variable Interest Entities," for additional information.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in ACE's gross revenues were zero for each of the three months ended September 30, 2015 and 2014, and zero and $1 million for the nine months ended September 30, 2015 and 2014, respectively.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Business Combinations (ASC 805)

In November 2014, the FASB issued new recognition and disclosure requirements related to pushdown accounting. The new recognition requirements grant an acquired entity (or its subsidiaries) the option to elect whether and when a new accounting and reporting basis (pushdown accounting) will be applied when an acquirer obtains control of the acquired entity. This election may be made by the acquired entity (or its subsidiaries) for future change-in-control events or for its most recent change-in-control event, and the acquired entity will be required to determine whether pushdown accounting will be applied in the reporting period in which the change-in-control event occurs or in a subsequent reporting period.

The new required disclosures include information that enables financial statement users to evaluate the effects of pushdown accounting. Disclosures are required to be made in the period in which pushdown accounting is applied and are expected to include both qualitative and quantitative information.

The new recognition and disclosure requirements became effective on a prospective basis on November 18, 2014.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Revenue from Contracts with Customers (ASC 606)

In May 2014, the FASB issued new recognition and disclosure requirements for revenue from contracts with customers, which supersedes the existing revenue recognition guidance. The new recognition requirements focus on when the customer obtains control of the goods or services, rather than the current risks and rewards model of recognition. The core principle of the new standard is that an entity will recognize revenue when it transfers goods or services to its customers in an amount that reflects the consideration an entity expects to be entitled to for those goods or services. The new disclosure requirements will include information intended to communicate the nature, amount, timing and any uncertainty of revenue and cash flows from applicable contracts, including any significant judgments and changes in judgments and assets recognized from the costs to obtain or fulfill a contract. Entities will generally be required to make more estimates and use more judgment under the new standard.

The new requirements will be effective for ACE beginning January 1, 2018, and may be implemented either retrospectively for all periods presented, or as a cumulative-effect adjustment as of January 1, 2018. Early adoption is permitted, but not before January 1, 2017. ACE is currently evaluating the potential impact of this new guidance on its consolidated financial statements and which implementation approach to select.

Presentation of Debt Issuance Costs (ASC 835)

In April 2015, the FASB issued new guidance for the presentation of debt issuance costs on the balance sheet. Debt issuance costs are currently required to be presented on the balance sheet as assets. However, under the new requirements, these debt issuance costs will be offset against the debt to which the costs relate. The new requirements will be effective for ACE beginning January 1, 2016, and are required to be implemented on a retrospective basis for all periods presented. Early adoption is permitted. ACE is currently evaluating the potential impact of this new guidance on its consolidated financial statements, but the impact is not expected to be material.

Business Combination (ASC 805)

In September 2015, the FASB issued new guidance on adjustments to provisional amounts recognized in a business combination, which are currently recognized on a retrospective basis. Under the new requirements, adjustments will be recognized in the reporting period in which the adjustments are determined. The effects of changes in depreciation, amortization, or other income arising from changes to the provisional amounts, if any, are included in earnings of the reporting period in which the adjustments to the provisional amounts are determined. An entity is also required to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The new requirements will be effective for ACE beginning January 1, 2016, and are required to be implemented on a prospective basis. Early adoption is permitted. ACE currently anticipates it may be affected by the new guidance if its Merger with Exelon is consummated.

(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

As further described in Note (1), "Organization," on April 29, 2014, PHI entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, PHI and its subsidiaries may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than pursuing the conclusion of the pending filings indicated below. To date, ACE has not requested such consent from Exelon and has not filed any new distribution base rate cases since entering into the Merger Agreement.

Bill Stabilization Adjustment

Although ACE proposed the adoption of a mechanism to decouple retail distribution revenue from the amount of power delivered to retail customers, this decoupling proposal has not to date been adopted.

New Jersey

Update and Reconciliation of Certain Under-Recovered Balances

In March 2015, ACE submitted its 2015 annual 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 non-utility generators (NUGs), and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and for ACE's uncollected accounts. As filed, the net impact of the proposed changes would have been an annual rate increase of approximately $52.0 million (revised to an increase of approximately $33.9 million on April 17, 2015, based upon updates for actual data through March 31, 2015). On May 19, 2015, the NJBPU approved a stipulation of settlement entered into by the parties providing for an overall annual rate increase of $33.9 million. The rate increase, which went into effect on June 1, 2015, was placed into effect provisionally, subject to a review by the NJBPU and the Division of Rate Counsel of the final underlying costs for reasonableness and prudence. On September 11, 2015, the NJBPU approved a stipulation of settlement in this proceeding, which made final the provisional rates that were placed into effect on June 1, 2015, with an adjustment that decreased the rate applicable to the residential class by $1.3 million. This rate increase of approximately $32.6 million will have no effect on ACE's operating income, since these revenues provide for recovery of deferred costs under an approved deferral mechanism.

Service Extension Contributions Refund Order

In July 2013, in compliance with a 2012 Superior Court of New Jersey Appellate Division (Appellate Division) court decision, the NJBPU released an order requiring utilities to issue refunds to persons or entities that paid non-refundable contributions for utility 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. Although ACE estimates that 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. Since the July 2013 order was released, ACE has paid less than $1 million in refund claims, the validity of each of which is investigated by ACE prior to making any such refunds. In September 2014, the NJBPU commenced a rulemaking proceeding to further implement the directives of the Appellate Division decision and, in December 2014, published a rule proposal for comment. The changes proposed by the NJBPU remove provisions distinguishing between growth areas and not-for-growth areas and provide formulae for allocating extension costs. ACE has been an active participant in the rulemaking proceeding. Final rules have not yet been promulgated by the NJBPU. At this time, ACE does not expect the amount it is ultimately required to refund will have a material effect on its consolidated financial condition, results of operations or cash flows, as the amount refunded will generally increase the value of ACE's property, plant and equipment and may ultimately be recovered through depreciation expense and cost of service in future electric distribution base rate cases.

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 NJBPU's current policy, 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. This policy has negatively impacted ACE's electric distribution base rate case outcomes and ACE's position is that the CTA should be eliminated. In an order issued in October 2014, the NJBPU determined that it is appropriate for affected consolidated groups to continue to include a CTA in New Jersey base rate filings, but that the CTA calculation will be modified to limit the look-back period for the calculation to five years, exclude transmission assets from the calculation, and allocate 25 percent of the final CTA amount as a reduction to the distribution revenue requirement. ACE anticipates that this revised methodology will significantly reduce the negative effects of the CTA in future base rate cases. In November 2014, the New Jersey Division of Rate Counsel filed an appeal of the NJBPU's CTA order in the Appellate Division. No stay of the October 2014 CTA order was requested in connection with the appeal. As such, barring an adverse finding by the Appellate Division, the order is in effect. The appeal remains pending.

FERC Transmission ROE Challenges

In February 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Municipal Electric Corporation, Inc. (DEMEC), filed a joint complaint at FERC against ACE and its affiliates, Pepco and Delmarva Power & Light Company (DPL), as well as Baltimore Gas and Electric Company (BGE). The complainants challenged the base return on equity (ROE) and certain protocols regarding the formula rate process associated with the transmission service that the 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. The 10.8% base ROE for facilities placed into service prior to 2006 receives 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 this complaint. In August 2014, FERC issued an order setting the matters in this proceeding for hearing, but holding the hearing in abeyance pending settlement discussions. The order also (i) directed that the evidence and analysis presented concerning ROE be guided by the new ROE methodology adopted by FERC in another proceeding (discussed below), and (ii) set a 15-month refund period that commenced on February 27, 2013, should a refund result from this proceeding. After settlement discussions among the parties in this matter reached an impasse, the settlement judge, in November 2014, issued an order terminating the settlement discussions and referring the matter to a presiding administrative law judge.

In June 2014, FERC issued an order in a proceeding in which ACE was not involved, in which it adopted a new ROE methodology for electric utilities. This new methodology replaces the existing one-step discounted cash flow analysis (which incorporates only short-term growth rates) traditionally used to derive ROE for electric utilities with the two-step discounted cash flow analysis (which incorporates both short-term and long-term measures of growth) used for natural gas and oil pipelines. As a result of the August 2014 FERC order discussed in the preceding paragraph, ACE applied an estimated ROE based on the two-step methodology announced by FERC for the 15-month period over which its transmission revenues would be subject to refund as a result of the challenge, and recorded estimated reserves for the entire 15-month refund period in the second quarter of 2014.

On December 8, 2014, the parties that filed the February 2013 complaint filed a second complaint against Pepco, DPL, ACE, as well as BGE, regarding the base transmission ROE, seeking a reduction from 10.8% to 8.8%. By order issued on February 9, 2015, FERC established a hearing on the second complaint and established a second 15-month refund period that commenced on December 8, 2014. Consistent with the prior challenge, Pepco, DPL and ACE applied an estimated ROE based on the two-step methodology described above, and in the fourth quarter of 2014 and in the first, second and third quarters of 2015 established reserves for the estimated refund based on the effective date of the second refund period of December 8, 2014. On February 20, 2015, the chief judge issued an order consolidating the two complaint proceedings and established an initial decision issuance deadline of February 29, 2016. On March 2, 2015, the presiding administrative law judge issued an order establishing a procedural schedule for the consolidated proceedings that provides for the hearing to commence on October 20, 2015.

Also during the third quarter of 2015, ACE further evaluated the reserves established for each of the two refund periods and, based on an updated assessment of market conditions, developments in other cases before FERC, litigation risk and other factors, increased its reserves to reflect management’s best estimate of the refund that is expected to result from these consolidated proceedings. As of September 30, 2015, ACE’s reserves for both of the refund periods totaled $8 million. A settlement entered into by the parties regarding the protocols (but not the ROE) raised in the February 2013 complaint was submitted to FERC on July 31, 2015 and is awaiting FERC approval.

To the extent that the final ROE established in these consolidated proceedings is lower than the ROE used to record the estimated reserves with respect to the February 2013 and the December 2014 complaints, each ten basis point reduction in the ROE would result in an increase in required reserves and a reduction of ACE’s operating income of $0.8 million.

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. ACE entered into the SOCAs under protest, as did the other electric distribution companies (EDCs) in New Jersey, arguing that the EDCs were denied due process and that the SOCAs violated certain of the requirements of the New Jersey law under which the SOCAs were established (the NJ SOCA Law). In October 2013, in light of the decision of the U.S. District Court for the District of New Jersey described below, the state appeals of the NJBPU implementation orders filed by the EDCs and generators were dismissed 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. In October 2013, the Federal district court ruled that the NJ SOCA Law is preempted by the Federal Power Act (FPA) and violates the Supremacy Clause, and is therefore null and void. In October 2013, the Federal district court issued an order ruling that the SOCAs are void, invalid and unenforceable, which order was affirmed by the U.S. Court of Appeals for the Third Circuit in September 2014. In November 2014 and December 2014, respectively, one of the generation companies and the NJBPU petitioned the U.S. Supreme Court to consider hearing an appeal of the Third Circuit decision. The petitions remain pending.

ACE terminated one of the three SOCAs effective July 1, 2013 due to the occurrence of an event of default on the part of the generation company counterparty. ACE terminated the remaining two SOCAs effective November 19, 2013, in response to the October 2013 Federal district court decision.

In response to the October 2013 Federal district court order, ACE, in the fourth quarter of 2013, derecognized both the derivative assets (liabilities) for the estimated fair value of the SOCAs and the related regulatory liabilities (assets) that it had established with respect to the SOCAs.

Merger Approval Proceedings

New Jersey

On June 18, 2014, Exelon, PHI and ACE, and certain of their respective affiliates, filed a petition with the NJBPU seeking approval of the Merger. To approve the Merger, the NJBPU must find the Merger is in the public interest, and consider the impact of the Merger on (i) competition, (ii) rates of ratepayers affected by the Merger, (iii) ACE's employees, and (iv) the provision of safe and reliable service at just and reasonable rates. On January 14, 2015, PHI, ACE, Exelon, certain of Exelon's affiliates, the Staff of the NJBPU, and the Independent Energy Producers of New Jersey filed a stipulation of settlement (the Stipulation) with the NJBPU in this proceeding. On February 11, 2015, the NJBPU approved the Stipulation and the Merger and on March 6, 2015, the NJBPU issued a written order approving the Stipulation.

The NJBPU order states that the Merger must be closed by November 1, 2015 unless extended by the NJBPU. On October 15, 2015, the NJBPU voted to extend the effectiveness of its Merger approval until June 30, 2016.

Federal Energy Regulatory Commission

On May 30, 2014, Exelon, PHI, Pepco, DPL and ACE, and certain of their respective affiliates, submitted to FERC a Joint Application for Authorization of Disposition of Jurisdictional Assets and Merger under Section 203 of the FPA. Under that section, FERC shall approve a merger if it finds that the proposed transaction will be consistent with the public interest. On November 20, 2014, FERC issued an order approving the Merger.

(7) PENSION AND OTHER POSTRETIREMENT BENEFITS

ACE accounts for its participation in PHI's single-employer plans, PHI's noncontributory retirement plan (the PHI Retirement Plan) and its other postretirement benefits plan, the Pepco Holdings, Inc. Welfare Plan for Retirees (the OPEB Plan), as participation in multiemployer plans. PHI's pension and other postretirement net periodic benefit cost for the three months ended September 30, 2015 and 2014, before intercompany allocations from the PHI Service Company, were $25 million and $16 million, respectively. ACE's allocated share was $3 million and $4 million for the three months ended September 30, 2015 and 2014, respectively. PHI's pension and other postretirement net periodic benefit cost for the nine months ended September 30, 2015 and 2014, before intercompany allocations from the PHI Service Company, were $73 million and $44 million, respectively. ACE's allocated share was $11 million and $10 million for the nine months ended September 30, 2015 and 2014, respectively.

For the nine months ended September 30, 2015 and 2014, ACE made no discretionary tax-deductible contributions to the PHI Retirement Plan.

(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, 2013, as permitted under the existing terms of the credit agreement, a request by PHI, Pepco, DPL and ACE to extend the credit facility termination date to August 1, 2018 was approved. All of the terms and conditions as well as pricing remained 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, $200 million, $250 million and $300 million for PHI, Pepco, DPL and ACE, respectively. 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 at September 30, 2015.

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.

At each of September 30, 2015 and December 31, 2014, 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 $413 million. 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.

Credit Facility Amendment

On May 20, 2014, PHI, Pepco, DPL and ACE entered into an amendment of and consent with respect to the credit agreement (the Consent). PHI was required to obtain the consent of certain of the lenders under the credit facility in order to permit the consummation of the Merger. Pursuant to the Consent, certain of the lenders consented to the consummation of the Merger and the subsequent conversion of PHI from a Delaware corporation to a Delaware limited liability company, provided that the Merger and subsequent conversion are consummated on or before October 29, 2015. In addition, the Consent amends the definition of "Change in Control" in the credit agreement to mean, following consummation of the Merger, an event or series of events by which Exelon no longer owns, directly or indirectly, 100% of the outstanding shares of voting stock of Pepco Holdings. PHI has requested an extension of the Consent to allow for completion of the Merger by June 30, 2016.

Commercial Paper

ACE maintains an on-going commercial paper program to address its short-term liquidity needs. As of September 30, 2015, the maximum capacity available under the program was $350 million, subject to available borrowing capacity under the credit facility.

ACE had $225 million of commercial paper outstanding at September 30, 2015. The weighted average interest rate for commercial paper issued by ACE during the nine months ended September 30, 2015 was 0.46% and the weighted average maturity of all commercial paper issued by ACE during the nine months ended September 30, 2015 was six days.

Other Financing Activities

Bond Payments

In July 2015, Atlantic City Electric Transition Funding LLC (ACE Funding) made the final payment of $1 million on its Series 2002-1 Bonds, Class A-3, and principal payments of $6 million on its Series 2002-1 Bonds, Class A-4 and $3 million on its Series 2003-1 Bonds, Class A-3.

Bond Retirements

In August 2015, ACE retired at maturity, $15 million of its secured medium-term notes series C.

Financing Activities Subsequent to September 30, 2015

Bond Payments

In October 2015, ACE Funding made the principal payments of $9 million on its Series 2002-1 Bonds, Class A-4 and $3 million on its Series 2003-1 Bonds, Class A-3.

(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,			
	2015		2014		2015		2014	
	(millions of dollars)							
Income tax at Federal statutory rate	$ 7	35.0%	$ 13	35.0%	$ 15	35.0%	$ 22	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	1	4.8%	2	5.4%	3	6.8%	4	6.3%
Depreciation	(1)	(4.8)%	—	—	(2)	(4.5)%	(1)	(1.6)%
Other, net	—	(1.7)%	(1)	(2.6)%	—	(0.9)%	(1)	(1.6)%
Consolidated income tax expense	$ 7	33.3%	$ 14	37.8%	$ 16	36.4%	$ 24	38.1%

(10) FAIR VALUE DISCLOSURES

Financial Instruments Measured at Fair Value on a Recurring Basis

ACE applies FASB guidance on fair value measurement (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, 2015 and December 31, 2014. 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, 2015			
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 and restricted cash equivalents				
Treasury funds	$ 30	$ 30	$ —	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the nine months ended September 30, 2015.

	Fair Value Measurements at December 31, 2014			
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 and restricted cash equivalents				
Treasury funds	$ 24	$ 24	$ —	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2014.

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.

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.

Other Financial Instruments

The estimated fair values of ACE's Long-term 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, 2015 and December 31, 2014 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 (Transition Bonds) 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, 2015			
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)	$ 998	$ —	$ 862	$ 136
Transition Bonds (b)	201	—	201	—
Total	$1,199	$ —	$ 1,063	$ 136

(a) The carrying amount for Long-term debt was $888 million as of September 30, 2015.
(b) The carrying amount for Transition Bonds, including amounts due within one year, was $184 million as of September 30, 2015.

Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Fair Value Measurements at December 31, 2014 (millions of dollars)			
LIABILITIES				
Debt instruments				
Long-term debt (a)	$1,035	$ —	$ 903	$ 132
Transition Bonds (b)	235	—	235	—
Total	$1,270	$ —	$ 1,138	$ 132

(a) The carrying amount for Long-term debt was $903 million as of December 31, 2014.
(b) The carrying amount for Transition Bonds, including amounts due within one year, was $215 million as of December 31, 2014.

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

(11) COMMITMENTS AND CONTINGENCIES

General Litigation

From time to time, ACE is named as a defendant in litigation, usually relating to general liability or auto liability claims that resulted in personal injury or property damage to third parties. ACE is self-insured against such claims up to a certain self-insured retention amount and maintains insurance coverage against such claims at higher levels, to the extent deemed prudent by management. In addition, ACE's contracts with its vendors generally require the vendors to name ACE as an additional insured for the amount at least equal to ACE's self-insured retention. Further, ACE's contracts with its vendors require the vendors to indemnify ACE for various acts and activities that may give rise to claims against ACE. Loss contingency liabilities for both asserted and unasserted claims are recognized if it is probable that a loss will result from such a claim and if the amounts of the losses can be reasonably estimated. Although the outcome of the claims and proceedings cannot be predicted with any certainty, management believes that there are no existing claims or proceedings that are likely to have a material adverse effect on ACE's financial condition, results of operations or cash flows. At September 30, 2015, ACE had recorded estimated loss contingency liabilities for general litigation totaling approximately $6 million (including amounts related to the matters specifically described below).

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, 2015 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 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 from 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.

(12) 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, 2015 and 2014 were approximately $36 million and $31 million, respectively. PHI Service Company costs directly charged or allocated to ACE for the nine months ended September 30, 2015 and 2014 were approximately $109 million and $91 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,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(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

(a) Included in Other operation and maintenance expense.
(b) Included in operating revenue.

As of September 30, 2015 and December 31, 2014, ACE had the following balances on its consolidated balance sheets due to related parties:

	September 30, 2015	December 31, 2014
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (14)	$ (14)
Other	(1)	(1)
Total	$ (15)	$ (15)

(a) Included in Accounts payable due to associated companies.

(13) VARIABLE INTEREST ENTITIES

ACE is required to consolidate a VIE in accordance with FASB ASC 810 if ACE or a subsidiary is the primary beneficiary of the VIE. The primary beneficiary of a VIE is typically the entity with both the power to direct activities most significantly impacting economic performance of the VIE and the obligation to absorb losses or receive benefits of the VIE that could potentially be significant to the VIE. ACE performed a qualitative analysis to determine whether a variable interest provided a controlling financial interest in any of the VIEs in which ACE has an interest at September 30, 2015, as described below.

Power Purchase Agreements

ACE is a party to three power purchase agreements (PPAs) with unaffiliated NUGs totaling 459 megawatts. One of the agreements ends in 2016 and the other two end in 2024. ACE has no equity or debt invested in these entities. In performing its VIE analysis, 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 has applied the scope exemption from the consolidation guidance.

Because ACE has no equity or debt invested in the NUGs, the maximum exposure to loss relates primarily to any above-market costs incurred for power. Due to unpredictability in the pricing for purchased energy under the PPAs, ACE is unable to quantify the maximum exposure to loss. The power purchase costs are recoverable from ACE’s customers through regulated rates. Purchase activities with the NUGs, including excess power purchases not covered by the PPAs, for the three months ended September 30, 2015 and 2014, were approximately $52 million and $56 million, respectively, of which approximately $50 million and $52 million, respectively, consisted of power purchases under the PPAs. Purchase activities with the NUGs, including excess power purchases not covered by the PPAs, for the nine months ended September 30, 2015 and 2014, were approximately $160 million and $182 million, respectively, of which approximately $151 million and $159 million, respectively, consisted of power purchases under the PPAs.

ACE Funding

In 2001, ACE established ACE Funding solely for the purpose of securitizing authorized portions of ACE’s recoverable stranded costs through the issuance and sale of Transition Bonds. The proceeds of the sale of each series of Transition Bonds were transferred to ACE in exchange for the transfer by ACE to Atlantic City Electric Transition Funding LLC (ACE Funding) of the right to collect a non-bypassable Transition Bond Charge from ACE customers pursuant to bondable stranded costs rate orders issued by the 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). 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 Transition Bonds have recourse only to the assets of ACE Funding. ACE owns 100 percent of the equity of ACE Funding, and PHI and ACE consolidate ACE Funding in their consolidated financial statements as ACE is the primary beneficiary of ACE Funding under the variable interest entity consolidation guidance.

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, to a lesser extent, the distribution and supply of natural gas (Power Delivery). Through Pepco Energy Services, Inc. and its subsidiaries (Pepco Energy Services), PHI provides energy savings performance contracting services, underground transmission and distribution construction and maintenance services and steam and chilled water under long-term contracts. For additional discussion, see "Pepco Energy Services" below.

Each of Power Delivery and Pepco Energy Services constitutes a separate segment for financial reporting purposes. Corporate and Other includes the remaining operations of the former Other Non-Regulated segment, certain parent company transactions (including interest expense on parent company debt and incremental external merger-related costs) and inter-company eliminations.

The following table sets forth the percentage contributions to consolidated operating revenue and operating income attributable to PHI segments for the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Percentage of Consolidated Operating Revenue				
Power Delivery	97%	95%	96%	94%
Pepco Energy Services	3%	5%	4%	6%
Corporate and Other	—	—	—	—
Percentage of Consolidated Operating Income				
Power Delivery	101%	133%	101%	112%
Pepco Energy Services	(1)%	(32)%	—	(10)%
Corporate and Other	—	(1)%	(1)%	(2)%
Percentage of Power Delivery Operating Revenue				
Power Delivery Electric	99%	98%	96%	96%
Power Delivery Gas	1%	2%	4%	4%

Agreement and Plan of Merger with Exelon Corporation

PHI entered into the Merger Agreement, with Exelon and Merger Sub, providing for the Merger, with PHI surviving the Merger as an indirect, wholly owned subsidiary of Exelon. Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of common stock of PHI (other than (i) shares owned by Exelon, Merger Sub or any other direct or indirect wholly owned subsidiary of Exelon and shares owned by PHI or any direct or indirect wholly owned subsidiary of PHI, and in each case not held on behalf of third parties (but not including shares held by PHI in any rabbi trust or similar arrangement in respect of any compensation plan or arrangement) and (ii) shares that are owned by stockholders who have perfected and not withdrawn a demand for appraisal rights pursuant to Delaware law), will be canceled and converted into the right to receive $27.25 in cash, without interest.

In connection with entering into the Merger Agreement, PHI entered into a Subscription Agreement with Exelon dated April 29, 2014 (the Subscription Agreement) with Exelon, pursuant to which on April 30, 2014, PHI issued to Exelon 9,000 originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share (the Preferred Stock), for a purchase price of $90 million. Exelon also committed pursuant to the Subscription Agreement to purchase 1,800 originally issued shares of Preferred Stock for a purchase price of $18 million at the end of each 90-day period following the date of the Subscription Agreement until the Merger closes or is terminated, up to a maximum of 18,000 shares of Preferred Stock for a maximum aggregate consideration of $180 million. In accordance with the Subscription Agreement, on each of July 29, 2014, October 27, 2014, January 26, 2015, April 27, 2015 and July 24, 2015, an additional 1,800 shares of Preferred Stock were issued by PHI to Exelon for a purchase price of $18 million. The holders of the Preferred Stock will be entitled to receive a cumulative, non-participating cash dividend of 0.1% per annum, payable quarterly, when, as and if declared by PHI's board of directors. The proceeds from the issuance of the Preferred Stock are not subject to restrictions and are intended to serve as a prepayment of any applicable reverse termination fee payable from Exelon to PHI. The Preferred Stock will be redeemable on the terms and in the circumstances set forth in the Merger Agreement and the Subscription Agreement.

The Merger Agreement provides for certain termination rights for each of PHI and Exelon, and further provides that, upon termination of the Merger Agreement under certain specified circumstances, PHI will be required to pay Exelon a termination fee of $259 million or reimburse Exelon for its expenses up to $40 million (which reimbursement of expenses shall reduce on a dollar for dollar basis any termination fee subsequently payable by PHI), provided, however, that if the Merger Agreement is terminated in connection with an acquisition proposal made under certain circumstances by a person who made an acquisition proposal between April 1, 2014 and the date of the Merger Agreement, the termination fee will be $293 million plus reimbursement of Exelon for its expenses up to $40 million (not subject to offset). In addition, if the Merger Agreement is terminated under certain circumstances due to the failure to obtain required regulatory approvals with respect to the Merger or the breach by Exelon of its obligations in respect of obtaining such regulatory approvals (a Regulatory Termination), PHI will be able to redeem any issued and outstanding Preferred Stock at par value, and in that case, Exelon will be required to pay all documented out-of-pocket expenses incurred by PHI in connection with the Merger Agreement or the transactions contemplated thereby, up to $40 million. If the Merger Agreement is terminated, other than for a Regulatory Termination, PHI will be required to redeem the Preferred Stock at the purchase price of $10,000 per share, plus any unpaid accrued and accumulated dividends thereupon.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (i) the approval of the Merger by the holders of a majority of the outstanding shares of common stock of PHI; (ii) the receipt of regulatory approvals required to consummate the Merger, including approvals from FERC, the Federal Communications Commission (FCC), the Delaware Public Service Commission (DPSC), the District of Columbia Public Service Commission (DCPSC), the Maryland Public Service Commission (MPSC), the New Jersey Board of Public Utilities (NJBPU) and the Virginia State Corporation Commission (VSCC); (iii) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (the HSR Act); and (iv) other customary closing conditions, including (a) the accuracy of each party's representations and warranties (subject to customary materiality qualifiers) and (b) each party's compliance with its obligations and covenants contained in the Merger Agreement (including covenants that may limit, restrict or prohibit PHI and its subsidiaries from taking specified actions during the period between the date of the Merger Agreement and the closing of the Merger or the termination of the Merger Agreement). In addition, the obligations of Exelon and Merger Sub to consummate the Merger are subject to the required regulatory approvals not imposing terms, conditions, obligations or commitments, individually or in the aggregate, that constitute a burdensome condition (as defined in the Merger Agreement).

On September 23, 2014, the stockholders of PHI approved the Merger, on October 7, 2014, the VSCC approved the Merger, and on November 20, 2014, FERC approved the Merger. In addition, the transfer of control of certain communications licenses held by certain of PHI's subsidiaries has been approved by the FCC. The NJBPU approved the Merger on February 11, 2015, and on October 15, 2015, voted to extend the effectiveness of its approval until June 30, 2016. The DPSC approved the Merger on May 19, 2015.

On December 22, 2014, the waiting period under the HSR Act expired. Although the Department of Justice (DOJ) allowed the waiting period under the HSR Act to expire without taking any action with respect to the Merger, the DOJ has not advised PHI that it has concluded its investigation. The expiration of the HSR Act waiting period allows for the closing of the Merger at any time on or before December 21, 2015. If the Merger is not completed by that date the parties will be required to refile the required Notification and Report Forms with the DOJ and Federal Trade Commission (FTC), which will restart the 30-day waiting period required by the HSR Act, during which time the Merger may not be consummated, unless these agencies authorize the early termination of the waiting period. PHI and Exelon currently anticipate that they will refile with the DOJ and FTC in November 2015.

On May 15, 2015, the MPSC approved the Merger, with conditions, including conditions that modify and supplement those originally proposed. On May 18, 2015, PHI and Exelon announced that they had committed to fulfill the modified, more stringent conditions and package of customer benefits imposed by the MPSC. Multiple parties have filed petitions for judicial review of the MPSC order by the Circuit Court of Queen Anne's County, Maryland, seeking to appeal the MPSC order. PHI is vigorously contesting these appeals. The MPSC order remains in effect during the appeals process. At this time, PHI is unable to predict the outcome of the proceeding.

On August 25, 2015, the DCPSC announced at a public meeting that it had denied the merger application, and on August 27, 2015, the DCPSC issued its written order related to the Merger. On September 28, 2015, Exelon, PHI and Pepco, and certain of their respective affiliates, filed an application for reconsideration with the DCPSC requesting reconsideration of the DCPSC order related to the Merger.

On October 6, 2015, Exelon, PHI and Pepco, and certain of their respective affiliates, entered into a Nonunanimous Full Settlement Agreement and Stipulation (the DC Settlement Agreement) with the District of Columbia Government, the Office of the People's Counsel and other parties, which DC Settlement Agreement contains commitments from Exelon and PHI above those contained in their original merger application.

Also on October 6, 2015, PHI, Exelon and Merger Sub entered into a Letter Agreement (the Letter Agreement), setting forth the terms and conditions under which the parties will file with the DCPSC (a) a Motion of Joint Applicants to Reopen the Record in Formal Case No. 1119 to Allow for Consideration of the DC Settlement Agreement (the Motion to Reopen), or (b) if the Motion to Reopen is not granted, a new merger application, requesting approval of the Merger on the terms and commitments agreed to in the DC Settlement Agreement. Pursuant to the Letter Agreement, PHI and Exelon each agrees, among other things, that neither party will exercise the termination rights each may have under the Merger Agreement on or after October 29, 2015, unless: (i) the DCPSC does not, within 45 days following the date on which the DC Settlement Agreement is filed with the DCPSC (the Settlement Filing Date), set a procedural schedule which allows for a final order for approval of the Merger within 150 days after the Settlement Filing Date, (ii) the DCPSC sets a schedule for action which does not allow for a final order for approval of the Merger within 150 days after the Settlement Filing Date, (iii) the DCPSC fails to issue a final order approving the Merger and the DC Settlement Agreement as filed without condition or modification within 150 days after the Settlement Filing Date, (iv) the DCPSC issues a final order denying approval of the Merger or the DC Settlement Agreement or adds conditions or makes modifications to the DC Settlement Agreement, (v) the DC Settlement Agreement is terminated for any reason, or (vi) on or after the date that is 151 days after the Settlement Filing Date a condition to closing of the Merger has not been satisfied or waived (other than those conditions that by their nature are to be satisfied at the closing). The Letter Agreement also provides that, subject to certain conditions, Exelon may, following receipt of all regulatory approvals consistent with the DC Settlement Agreement, delay closing of the Merger for up to 30 days to engage in capital markets transactions to raise additional funds required to consummate the Merger.

On October 6, 2015, following execution of the DC Settlement Agreement and the Letter Agreement, Exelon, PHI and Pepco, and certain of their respective affiliates, filed with the DCPSC the Motion to Reopen requesting consideration of the DC Settlement Agreement and approval of the Merger on such terms and conditions set forth in the DC Settlement Agreement, without condition or modification, and to stay further proceedings on the application for reconsideration filed by the parties on September 28, 2015 and suspend the time period for reconsideration pending the DCPSC's consideration of the DC Settlement Agreement.

While the Merger has been pending, PHI's utility subsidiaries, in accordance with the terms of the Merger Agreement, have not filed any new distribution base rate cases, thereby foregoing rate increases that they might otherwise have sought. At the same time, each of the utility subsidiaries generally has maintained its pre-Merger Agreement level of infrastructure spending in its service territory. If the Merger is terminated as described above, PHI and each of its utility subsidiaries would commence filing distribution base rate cases in each of the jurisdictions and would expect that they will be required to undertake certain actions to address their ongoing results of operations and financial condition. Such actions are likely to include, but may not be limited to, reductions in capital and operation and maintenance expenditures, and the reevaluation of PHI's common stock dividend policy. For further discussion, please refer to Part II, Item 1A. "Risk Factors" of this report.

Power Delivery

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

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 federal and municipal government services, professional, scientific and technical services, educational and health services, banking, casinos, tourism and transportation.
- Industrial activities in the region include chemical, glass, pharmaceutical, food processing and oil refining.

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, the distribution and supply of 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 in Delaware, the District of Columbia and Maryland, and Basic Generation Service (BGS) in New Jersey. 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 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 can also be affected by economic conditions generally, the level of commercial activity affecting a region, industry or business sector within a service territory, 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, pursuant to which 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, 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 DPSC.

In accounting for the BSA in Maryland and the District of Columbia, a Revenue Decoupling Adjustment (an adjustment equal to the amount by which revenue from distribution sales differs from the revenue that Pepco and DPL are entitled to earn based on the approved distribution charge per customer) 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.

PHI's utility subsidiaries allocate a substantial portion of their total capital expenditures to improving the reliability of their electrical transmission and distribution systems and replacing aging infrastructure throughout their service territories. These activities include:

- Identifying and upgrading under-performing feeder lines;
- Adding new facilities to support load;
- Installing distribution automation systems on both the overhead and underground network systems; and
- Rejuvenating and replacing underground residential cables.

<u>*Power Delivery Initiatives and Activities*</u>

District of Columbia Power Line Undergrounding Initiative

For information about the District of Columbia Power Line Undergrounding Initiative, please refer to Note (7), "Regulatory Matters – District of Columbia Power Line Undergrounding Initiative," to the consolidated financial statements of PHI.

MPSC New Generation Contract Requirement

For information about the MPSC New Generation Contract Requirement, please refer to Note (7), "Regulatory Matters – MPSC New Generation Contract Requirement," to the consolidated financial statements of PHI.

Smart Grid Initiatives

PHI's utility subsidiaries are engaged in transforming the power grid that they own and operate into a "smart grid," a network of automated digital devices capable of collecting and communicating large amounts of real-time data.

A central component of the smart grid is AMI, a system that collects, measures and analyzes energy usage data from advanced digital meters, known as "smart meters." Also critical to the operation of the smart grid is distribution automation technology, which is comprised of automated devices that have internal intelligence and can be controlled remotely to better manage power flow and restore service quickly and more safely. Both the AMI system and distribution automation are enabled by advanced technology that communicates with devices installed on the energy delivery system and transmits energy usage data to the host utility. The implementation of the AMI system and distribution automation involves an integration of technologies provided by multiple vendors.

As of September 30, 2015, Pepco and DPL have completed the installation and activation of smart meters in the District of Columbia, Maryland and Delaware service territories. The DCPSC, the MPSC and the DPSC approved the creation by PHI's utility subsidiaries of regulatory assets to defer AMI costs between rate cases and to defer carrying charges 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 carrying charge is deferred.

In 2010, two of PHI's utility subsidiaries were granted cash awards in the aggregate amount of $168 million by the U.S. Department of Energy (DOE) to support their smart grid initiatives.

- Pepco was awarded $149 million for AMI, direct load control, distribution automation and communications infrastructure, all of which has been received through September 30, 2015.
- ACE was awarded $19 million for direct load control, distribution automation and communications infrastructure, all of which has been received through September 30, 2015.

Mitigation of Regulatory Lag

An important factor in the ability of PHI's utility subsidiaries to earn their authorized ROE is the willingness of applicable public service commissions to adequately address the shortfall in revenues in a utility's rate structure 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, DPL and ACE are currently experiencing significant regulatory lag because investments in rate base and operating expenses are increasing more rapidly than their revenue growth.

In an effort to minimize the effects of regulatory lag, prior to the initial execution of the Merger Agreement in April 2014, PHI's utility subsidiaries had been filing electric distribution base rate cases every nine to twelve months in each of their jurisdictions, pursuing alternative ratemaking mechanisms, evaluating potential reductions in planned capital expenditures, and discussing with the regulatory community and other stakeholders the changing regulatory model economics that are causing regulatory lag.

As further described in "– Agreement and Plan of Merger with Exelon Corporation," PHI has entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, PHI and its subsidiaries may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than concluding pending filings. To date, PHI has not requested such consent from Exelon and has not filed any new distribution base rate cases since entering into the Merger Agreement. Accordingly, PHI's efforts to mitigate regulatory lag have been delayed pending the closing of the Merger or the termination of the Merger Agreement.

Transmission ROE Challenges

For information about the challenges to the utility subsidiaries' base ROE and certain protocols regarding the formula rate process, each associated with the transmission services they provide, please refer to Note (7), "Regulatory Matters – Rate Proceedings – FERC Transmission ROE Challenges," to the consolidated financial statements of PHI.

Pepco Energy Services

Pepco Energy Services is focused on growing its energy savings business and its underground transmission and distribution construction business while managing its thermal assets in Atlantic City. The energy savings business focuses on developing, building and operating energy savings performance solutions primarily for federal, state and local government customers. Pepco Energy Services' underground transmission and distribution construction business focuses on providing construction and maintenance services for electric power utilities in North America.

PHI guarantees the obligations of Pepco Energy Services under certain contracts in its energy savings performance contracting business and underground transmission and distribution construction business. At September 30, 2015, PHI's guarantees of Pepco Energy Services' obligations under these contracts totaled $259 million. PHI also guarantees the obligations of Pepco Energy Services under surety bonds obtained by Pepco Energy Services for construction projects. These guarantees totaled $167 million at September 30, 2015.

During 2012, Pepco Energy Services deactivated its Buzzard Point and Benning Road oil-fired generation facilities. Pepco Energy Services completed demolition of the Benning Road generation facility in July 2015 and recognized the scrap metal salvage value of the facility as a reduction in its demolition expenses over the life of the project.

Revenues associated with Pepco Energy Services' combined heat and power thermal generating facilities and operations in Atlantic City are derived from long-term contracts with a few major customers in the Atlantic City hotel and casino industry. The carrying amount of Pepco Energy Services' long-lived assets in Atlantic City at September 30, 2015 totaled $2 million, after impairment losses aggregating $81 million that were recorded during the third and fourth quarters of 2014. In September 2014, two significant customers of these thermal operations declared Chapter 11 bankruptcy. One of the customers closed operations in September 2014 and Pepco Energy Services continues to provide this customer with steam and chilled water service under a contract with lower rates which began April 1, 2015. The second customer terminated its contract with Pepco Energy Services on March 31, 2015. Two other significant customers of the thermal operations declared Chapter 11 bankruptcy in January 2015 and Pepco Energy Services continues to provide service to those customers under existing contracts. Future developments with respect to these and other customers in Atlantic City may require Pepco Energy Services to perform additional impairment analyses of the thermal operations and certain related assets. If these assets are determined to be further impaired, Pepco Energy Services would reduce the carrying value of these assets by the amount of the impairment and record a corresponding non-cash charge to earnings. Moreover, the contract changes and termination referred to above are expected to reduce Pepco Energy Services' future earnings and cash flows associated with its thermal operations in Atlantic City.

Corporate and Other

Corporate and Other includes the remaining operations of the former Other Non-Regulated segment, certain parent company transactions (including interest expense on parent company debt and incremental external Merger-related costs) and inter-company eliminations.

Earnings Overview

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

	2015	2014	Change
	(millions of dollars)		
Power Delivery	$ 88	$112	$ (24)
Pepco Energy Services	—	(27)	27
Corporate and Other	3	(6)	9
Total PHI Net Income	$ 91	$ 79	$ 12

Net income for the three months ended September 30, 2015 was $91 million, or $0.36 per share, compared to $79 million, or $0.31 per share, for the three months ended September 30, 2014.

Net income for the three months ended September 30, 2015 included the items set forth below, which are presented net of related federal and state income taxes and are in millions of dollars:

- Incremental Merger-related transaction costs in Corporate and Other of $1 million ($1 million pre-tax)
- Change in fair value of derivative related to the Preferred Stock in Corporate and Other of $10 million ($15 million pre-tax)

Net income for the three months ended September 30, 2014 included the items set forth below, which are presented net of related federal and state income taxes and are in millions of dollars:

- Asset impairment loss in Pepco Energy Services of $32 million ($53 million pre-tax)
- Incremental Merger-related transaction costs in Corporate and Other of $3 million ($4 million pre-tax)

Excluding the items listed above, net income would have been $82 million, or $0.33 per share for the three months ended September 30, 2015, and $114 million, or $0.45 per share for the three months ended September 30, 2014.

PHI discloses net income and related per share data excluding certain 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 and related per share data in accordance with accounting principles generally accepted in the United States of America (GAAP).

Discussion of Operating Segment Net Income Variances:

Power Delivery's $24 million decrease in earnings was primarily due to the following:

- A decrease of $12 million due to higher operation and maintenance expense primarily related to the implementation of a new customer information system, higher tree trimming and system maintenance costs, higher storm restoration and environmental remediation costs and higher employee-related expenses.
- A decrease of $7 million associated with Default Electricity Supply margins for ACE, primarily attributable to a decrease in unbilled revenue.
- A decrease of $6 million from lower network service transmission revenues primarily due to an increase in refund reserves related to the FERC ROE challenges.
- A decrease of $4 million due to higher property tax expense, primarily due to increases in plant investment and tax rates.

- A decrease of $3 million due to higher depreciation and amortization expense primarily resulting from increases in plant investment.
- A decrease of $2 million due to higher interest expense.
- An increase of $7 million in regulated Transmission and Distribution (T&D) electric revenue primarily due to the effect of warmer weather during 2015.
- An increase of $2 million from electric distribution base rate increases in 2014 (primarily ACE in New Jersey).

Pepco Energy Services' $27 million decrease in net loss was primarily due to an asset impairment loss of $32 million (after-tax) recorded in 2014 associated with its combined heat and power thermal generating facility in Atlantic City, partially offset by tax benefits received in 2014 from deductions for energy efficiency construction projects.

Corporate and Other's $9 million decrease in net loss was primarily due to a $10 million (after-tax) increase in the fair value of a derivative related to the Preferred Stock.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

	2015	2014	Change
		(millions of dollars)	
Power Delivery	$211	$262	$ (51)
Pepco Energy Services	5	(25)	30
Corporate and Other	(19)	(30)	11
Total PHI Net Income	$197	$207	$ (10)

Net income for the nine months ended September 30, 2015 was $197 million, or $0.78 per share, compared to $207 million, or $0.82 per share, for the nine months ended September 30, 2014.

Net income for the nine months ended September 30, 2015 included the items set forth below, which are presented net of related federal and state income taxes and are in millions of dollars:

- Incremental Merger-related transaction costs in Corporate and Other of $10 million ($10 million pre-tax)
- Change in fair value of derivative related to preferred stock in Corporate and Other of $10 million ($15 million pre-tax)

Net income for the nine months ended September 30, 2014 included the items set forth below, which are presented net of related federal and state income taxes and are in millions of dollars:

- Asset impairment loss in Pepco Energy Services of $32 million ($53 million pre-tax)
- Incremental Merger-related transaction costs in Corporate and Other of $17 million ($19 million pre-tax)

Excluding the items listed above, net income would have been $197 million, or $0.78 per share for the nine months ended September 30, 2015, and $256 million, or $1.02 per share for the nine months ended September 30, 2014.

PHI discloses net income and related per share data excluding certain 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 and related per share data in accordance with GAAP.

Discussion of Operating Segment Net Income Variances:

Power Delivery's $51 million decrease in earnings was primarily due to the following:

- A decrease of $55 million due to higher operation and maintenance expense primarily related to the implementation of a new customer information system, higher tree trimming and system maintenance costs, higher bad debt expense, higher storm restoration and environmental remediation costs, previously expensed District of Columbia rate case costs established as a regulatory asset in 2014 and higher employee-related expenses.
- A decrease of $10 million due to higher depreciation and amortization expense primarily resulting from increases in plant investment.
- A decrease of $7 million due to higher interest expense.
- A decrease of $5 million related to gains recorded in 2014 associated with condemnation awards for certain Pepco transmission property.
- A decrease of $5 million associated with Default Electricity Supply margins for ACE, primarily attributable to a decrease in unbilled revenue.
- A decrease of $2 million from lower network service transmission revenues primarily due to an increase in refund reserves related to the FERC ROE challenges.
- An increase of $20 million from electric distribution base rate increases in 2014 (Pepco in the District of Columbia and Maryland, and ACE in New Jersey).
- An increase of $12 million in regulated T&D electric revenue primarily due to the effect in 2015 of colder weather during the first quarter and warmer weather during the second and third quarters.

Pepco Energy Services' $30 million decrease in net loss was primarily due to an asset impairment loss of $32 million (after-tax) recorded in 2014 associated with its combined heat and power thermal generating facility in Atlantic City.

Corporate and Other's $11 million decrease in net loss was primarily due to a $10 million (after-tax) increase in the fair value of a derivative related to the Preferred Stock and lower incremental Merger-related transaction costs in 2015, partially offset by unfavorable state income tax adjustments.

Consolidated Results of Operations

The following results of operations discussion compares the three months ended September 30, 2015 to the three months ended September 30, 2014. All amounts in the tables (except sales and customers) are in millions of dollars.

Operating Revenue

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

	2015	2014	Change
Power Delivery	$1,316	$1,242	$ 74
Pepco Energy Services	47	73	(26)
Corporate and Other	(1)	(2)	1
Total Operating Revenue	$1,362	$1,313	$ 49

Power Delivery

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

	2015	2014	Change
Regulated T&D Electric Revenue	$ 672	$ 650	$ 22
Default Electricity Supply Revenue	607	559	48
Other Electric Revenue	18	13	5
Total Electric Operating Revenue	1,297	1,222	75
Regulated Gas Revenue	15	17	(2)
Other Gas Revenue	4	3	1
Total Gas Operating Revenue	19	20	(1)
Total Power Delivery Operating Revenue	$1,316	$1,242	$ 74

Regulated 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 a 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 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 (the Transition Bonds), and revenue in the form of transmission enhancement credits that PHI's utility subsidiaries receive as transmission owners from PJM in consideration for approved regional transmission expansion plan expenditures.

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

	2015	2014	Change
Regulated T&D Electric Revenue			
Residential	$ 279	$ 251	$ 28
Commercial and industrial	289	286	3
Transmission and other	104	113	(9)
Total Regulated T&D Electric Revenue	$ 672	$ 650	$ 22

	2015	2014	Change
Regulated T&D Electric Sales (Gigawatt hours (GWh))			
Residential	5,200	4,769	431
Commercial and industrial	7,999	7,953	46
Transmission and other	50	58	(8)
Total Regulated T&D Electric Sales	13,249	12,780	469

	2015	2014	Change
Regulated T&D Electric Customers (in thousands)			
Residential	1,685	1,656	29
Commercial and industrial	200	199	1
Transmission and other	2	2	—
Total Regulated T&D Electric Customers	1,887	1,857	30

Regulated T&D Electric Revenue increased by $22 million primarily due to:

- An increase of $16 million due to an EmPower Maryland (a Maryland demand-side management program for Pepco and DPL) rate increase effective February 2015 (which is substantially offset by a corresponding increase in Depreciation and Amortization).
- An increase of $13 million due to higher sales primarily as a result of warmer weather during the third quarter of 2015, as compared to 2014.
- An increase of $5 million due to customer growth in the third quarter of 2015, as compared to 2014, primarily in the residential classes.
- An increase of $4 million due to electric distribution base rate increases (primarily ACE effective September 2014).

The aggregate amount of these increases was partially offset by:

- A decrease of $9 million in transmission revenue due to the establishment of a reserve related to the FERC ROE challenges, partially offset by higher rates effective June 1, 2015 related to increases in transmission plant investment and operating expenses.
- A decrease of $8 million due to lower average customer usage.

Default Electricity Supply

	2015	2014	Change
Default Electricity Supply Revenue			
Residential	$421	$366	$ 55
Commercial and industrial	154	156	(2)
Other	32	37	(5)
Total Default Electricity Supply Revenue	$607	$559	$ 48

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.

	2015	2014	Change
Default Electricity Supply Sales (GWh)			
Residential	4,213	3,868	345
Commercial and industrial	1,496	1,613	(117)
Other	9	12	(3)
Total Default Electricity Supply Sales	5,718	5,493	225

	2015	2014	Change
Default Electricity Supply Customers (in thousands)			
Residential	1,440	1,373	67
Commercial and industrial	130	128	2
Other	—	—	—
Total Default Electricity Supply Customers	1,570	1,501	69

Default Electricity Supply Revenue increased by $48 million primarily due to:

- An increase of $31 million due to higher sales primarily as a result of warmer weather during the third quarter of 2015, as compared to 2014.
- An increase of $25 million as a result of higher Default Electricity Supply rates.
- An increase of $3 million due to higher sales primarily as a result of customer migration from competitive suppliers.

The aggregate amount of these increases was partially offset by:

- A net decrease of $5 million due to lower ACE and DPL non-weather related average customer usage, partially offset by higher usage at Pepco.
- A decrease of $5 million in wholesale energy and capacity resale revenues primarily due to lower market prices for the resale of electricity and capacity purchased from NUGs.

The variances described above with respect to Default Electricity Supply Revenue include the effects of a decrease of $8 million in ACE's BGS unbilled revenue resulting primarily from lower average customer usage in the unbilled revenue period for the three months ended September 30, 2015 as compared to the corresponding period in 2014. Such a decrease in ACE's BGS unbilled revenue has the effect of directly decreasing the profitability of ACE's Default Electricity Supply business ($5 million decrease in net income) as these unbilled revenues are not included in the deferral calculation until they are billed to customers under the BGS terms approved by the NJBPU.

Regulated Gas

	2015	2014	Change
Regulated Gas Revenue			
Residential	$ 8	$ 9	$ (1)
Commercial and industrial	5	6	(1)
Transportation and other	2	2	—
Total Regulated Gas Revenue	$ 15	$ 17	$ (2)

	2015	2014	Change
Regulated Gas Sales (million cubic feet)			
Residential	377	404	(27)
Commercial and industrial	734	745	(11)
Transportation and other	1,144	1,075	69
Total Regulated Gas Sales	2,255	2,224	31

	2015	2014	Change
Regulated Gas Customers (in thousands)			
Residential	119	117	2
Commercial and industrial	10	9	1
Transportation and other	—	—	—
Total Regulated Gas Customers	129	126	3

Regulated Gas Revenue decreased by $2 million primarily due to lower sales as a result of warmer weather during the third quarter of 2015, as compared to 2014.

Pepco Energy Services

Pepco Energy Services' operating revenue decreased by $26 million primarily due to:

- A decrease of $23 million in its energy savings business primarily associated with lower construction activity.
- A decrease of $4 million from its thermal business in Atlantic City primarily due to the loss of a customer in 2015.
- An increase of $1 million in underground transmission and distribution 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:

	2015	2014	Change
Power Delivery	$581	$543	$ 38
Pepco Energy Services	37	56	(19)
Corporate and Other	(1)	—	(1)
Total	$617	$599	$ 18

Power Delivery

Power Delivery's Fuel and Purchased Energy expense 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 increased by $38 million primarily due to:

- An increase of $31 million due to higher average electricity costs under Default Electricity Supply contracts.
- An increase of $19 million due to higher electricity sales primarily as a result of warmer weather during the third quarter of 2015, as compared to 2014.
- An increase of $7 million primarily due to customer migration from competitive suppliers.

The aggregate amount of these increases was partially offset by:

- A decrease of $18 million in deferred electricity expense primarily due to lower revenue associated with Pepco and DPL Default Electricity Supply sales, which resulted in a lower rate of recovery of Default Electricity Supply costs.
- A decrease of $1 million in the cost of gas purchases for on-system sales as a result of lower prices.

Pepco Energy Services

Pepco Energy Services' Fuel and Purchased Energy expense and Other Services Cost of Sales decreased by $19 million primarily due to:

- A decrease of $19 million in its energy savings business primarily associated with decreased construction activity.
- A decrease of $1 million in its thermal business primarily due to the loss of a customer in Atlantic City.
- An increase of $1 million associated with increased underground transmission and distribution construction activities.

Other Operation and Maintenance

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

	2015	2014	Change
Power Delivery	$261	$238	$ 23
Pepco Energy Services	11	15	(4)
Corporate and Other	(15)	(11)	(4)
Total	$257	$242	$ 15

Power Delivery

Other Operation and Maintenance expense for Power Delivery increased by $23 million primarily due to:

- An increase of $6 million associated with higher tree trimming and system maintenance costs.
- An increase of $5 million due to implementation and support costs related to a new customer information system.
- An increase of $4 million in storm restoration costs.
- An increase of $3 million in customer service costs.
- An increase of $3 million in environmental remediation costs.
- An increase of $2 million in bad debt expense, of which $1 million is deferred and recoverable.

On June 23, 2015, the service territories of DPL and ACE were affected by a severe storm with damaging winds and heavy rains. This storm resulted in widespread customer outages and caused damage to the electric transmission and distribution systems. Storm restoration activity commenced immediately following the storm and continued into July 2015, with the majority of the incremental storm restoration costs occurring in the second quarter of 2015.

Total incremental storm restoration costs incurred by PHI for the three months ended September 30, 2015 were $9 million, with $3 million incurred for repair work and $6 million incurred as capital expenditures. Costs incurred for repair work of $3 million were deferred as regulatory assets to reflect the probable recovery of these costs in Maryland and New Jersey. As of September 30, 2015, the total incremental storm restoration costs associated with the June 23, 2015 storm included $10 million of estimated costs for unbilled restoration services provided by certain outside contractors. Actual costs for these services may vary from the estimates. DPL and ACE intend to pursue recovery of these incremental storm restoration costs in their respective jurisdictions in their next electric distribution base rate cases.

The increased costs referred to above for system maintenance, implementation and support of a new customer information system, storm restoration and customer service each involve internal labor costs which reflect a higher level of pension benefit cost in 2015, as compared to 2014.

Pepco Energy Services

Other Operation and Maintenance expense for Pepco Energy Services decreased $4 million primarily due to:

- A decrease of $2 million associated with a bad debt expense recorded in 2014 for an account receivable from a customer in Atlantic City.
- A decrease of $2 million from a combination of lower personnel expenses in its energy savings business and lower costs associated with the demolition of its Benning Road generation facility that was completed in July 2015.

Corporate and Other

Other Operation and Maintenance expense for Corporate and Other decreased by $4 million primarily due to lower internal and external Merger-related transaction costs during the third quarter of 2015, as compared to 2014.

Depreciation and Amortization

Depreciation and Amortization expense increased by $33 million to $178 million in 2015 from $145 million in 2014 primarily due to:

- An increase of $17 million in amortization of regulatory assets primarily associated with the EmPower Maryland surcharge rate increase effective February 2015 (which is offset by an increase in Regulated T&D Electric Revenue).
- An increase of $6 million in amortization of stranded costs, primarily as the result of higher revenue due to a rate increase effective October 2014 for the ACE Market Transition Charge tax (partially offset in Default Supply Electricity Revenue).
- An increase of $6 million due to utility plant additions.
- An increase of $2 million in amortization of software, primarily related to the implementation of a new customer information system.
- An increase of $2 million in the Delaware Renewable Energy Portfolio Standards deferral (which is substantially offset by a corresponding increase in Regulated T&D Electric Revenue).

Other Taxes

Other Taxes increased by $5 million to $114 million in 2015 from $109 million in 2014. The increase was primarily due to higher property taxes.

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 costs incurred by ACE related to the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals). The cost of electricity purchased is reported under Fuel and Purchased Energy expense and the corresponding revenue is reported under Default Electricity Supply Revenue. The costs of the New Jersey Societal Benefit Program are 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 $14 million to an expense of $13 million in 2015 as compared to an expense reduction of $1 million in 2014 primarily due to an increase in deferred electricity expense as a result of higher Default Electricity Supply revenue rates.

Impairment Loss

PHI's operating expenses for the three months ended September 30, 2014, include an impairment loss of $53 million ($32 million after-tax) at Pepco Energy Services associated with its combined heat and power thermal generating plant and operation assets in Atlantic City.

Other Income (Expenses)

Other Expenses (which are net of Other Income) decreased by $10 million to a net expense of $43 million in 2015 from a net expense of $53 million in 2014 primarily due to:

- An increase of $15 million in income due to a change in the fair value of the derivative related to the Preferred Stock.
- An increase of $3 million in interest expense primarily associated with higher long-term debt and higher short-term debt.

Income Tax Expense

PHI's income tax expense increased by $15 million to $49 million in 2015 from $34 million in 2014. PHI's consolidated effective income tax rates for the three months ended September 30, 2015 and 2014 were 35.0% and 30.1%, respectively.

The increase in the effective tax rate primarily resulted from a decrease in tax benefits recorded in 2015 related to certain energy efficiency-related tax deductions associated with Pepco Energy Services' energy savings performance contracting services.

Consolidated Results of Operations

The following results of operations discussion compares the nine months ended September 30, 2015 to the nine months ended September 30, 2014. All amounts in the tables (except sales and customers) are in millions of dollars.

Operating Revenue

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

	2015	2014	Change
Power Delivery	$3,707	$3,554	$ 153
Pepco Energy Services	170	212	(42)
Corporate and Other	(4)	(6)	2
Total Operating Revenue	$3,873	$3,760	$ 113

Power Delivery

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

	2015	2014	Change
Regulated T&D Electric Revenue	$1,842	$1,736	$ 106
Default Electricity Supply Revenue	1,692	1,629	63
Other Electric Revenue	43	44	(1)
Total Electric Operating Revenue	3,577	3,409	168
Regulated Gas Revenue	120	129	(9)
Other Gas Revenue	10	16	(6)
Total Gas Operating Revenue	130	145	(15)
Total Power Delivery Operating Revenue	$3,707	$3,554	$ 153

Regulated 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 a 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 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's utility subsidiaries receive as transmission owners from PJM in consideration for approved regional transmission expansion plan expenditures.

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

	2015	2014	Change
Regulated T&D Electric Revenue			
Residential	$ 714	$ 640	$ 74
Commercial and industrial	803	768	35
Transmission and other	325	328	(3)
Total Regulated T&D Electric Revenue	$ 1,842	$1,736	$ 106

	2015	2014	Change
Regulated T&D Electric Sales (GWh)			
Residential	14,593	13,441	1,152
Commercial and industrial	22,365	22,596	(231)
Transmission and other	167	182	(15)
Total Regulated T&D Electric Sales	37,125	36,219	906

	2015	2014	Change
Regulated T&D Electric Customers (in thousands)			
Residential	1,685	1,656	29
Commercial and industrial	200	199	1
Transmission and other	2	2	—
Total Regulated T&D Electric Customers	1,887	1,857	30

Regulated T&D Electric Revenue increased by $106 million primarily due to:

- An increase of $42 million due to EmPower Maryland rate increases effective February 2014 and 2015 (which is substantially offset by a corresponding increase in Depreciation and Amortization).
- An increase of $35 million due to electric distribution base rate increases (Pepco in the District of Columbia effective April 2014, and in Maryland effective July 2014; ACE effective September 2014).
- An increase of $20 million due to higher sales primarily as a result of colder weather during the first quarter and warmer weather during the second and third quarters of 2015, as compared to 2014.
- An increase of $7 million primarily due to rate increases effective June 2014 and June 2015 associated with the Renewable Portfolio Surcharge in Delaware (which is substantially offset in Fuel and Purchased Energy and Depreciation and Amortization).
- An increase of $6 million due to customer growth in 2015 primarily in the residential classes.
- An increase of $5 million in capacity revenue as a result of expanding Maryland demand side management programs (which is partially offset in Depreciation and Amortization).

The aggregate amount of these increases was partially offset by:

- A decrease of $5 million in revenue related to the resale by DPL of renewable energy to PJM (which is substantially offset in Purchased Energy and Depreciation and Amortization).
- A decrease of $3 million due to lower ACE non-weather related average residential customer usage.
- A decrease of $2 million in transmission revenue due to the establishment of a reserve related to the FERC ROE challenges, partially offset by higher rates effective June 1, 2014 and June 1, 2015 related to increases in transmission plant investment and operating expenses.

Default Electricity Supply

	2015	2014	Change
Default Electricity Supply Revenue			
Residential	$1,152	$1,025	$ 127
Commercial and industrial	429	429	—
Other	111	175	(64)
Total Default Electricity Supply Revenue	$1,692	$1,629	$ 63

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.

	2015	2014	Change
Default Electricity Supply Sales (GWh)			
Residential	11,948	10,835	1,113
Commercial and industrial	4,240	4,175	65
Other	31	33	(2)
Total Default Electricity Supply Sales	16,219	15,043	1,176

	2015	2014	Change
Default Electricity Supply Customers (in thousands)			
Residential	1,440	1,373	67
Commercial and industrial	130	128	2
Other	—	—	—
Total Default Electricity Supply Customers	1,570	1,501	69

Default Electricity Supply Revenue increased by $63 million primarily due to:

- An increase of $56 million due to higher sales primarily as a result of colder weather during the first quarter and warmer weather during the second and third quarters of 2015, as compared to 2014.
- An increase of $48 million due to higher sales primarily as a result of customer migration from competitive suppliers.
- A net increase of $14 million as a result of higher ACE Default Electricity Supply rates, partially offset by lower Pepco and DPL rates.
- A net increase of $11 million due to higher Pepco and DPL non-weather related average customer usage, partially offset by lower usage at ACE.

The aggregate amount of these increases was partially offset by a decrease of $66 million in wholesale energy and capacity resale revenues primarily due to lower market prices for the resale of electricity and capacity purchased from NUGs.

The variances described above with respect to Default Electricity Supply Revenue include the effects of a decrease of $5 million in ACE's BGS unbilled revenue resulting primarily from lower average customer usage in the unbilled revenue period for the nine months ended September 30, 2015 as compared to the corresponding period in 2014. Such a decrease in ACE's BGS unbilled revenue has the effect of directly decreasing the profitability of ACE's Default Electricity Supply business ($3 million decrease in net income) as these unbilled revenues are not included in the deferral calculation until they are billed to customers under the BGS terms approved by the NJBPU.

Regulated Gas

	2015	2014	Change
Regulated Gas Revenue			
Residential	$ 73	$ 77	$ (4)
Commercial and industrial	39	44	(5)
Transportation and other	8	8	—
Total Regulated Gas Revenue	$ 120	$ 129	$ (9)

	2015	2014	Change
Regulated Gas Sales (million cubic feet)			
Residential	6,311	6,114	197
Commercial and industrial	4,409	4,285	124
Transportation and other	4,716	4,737	(21)
Total Regulated Gas Sales	15,436	15,136	300

	2015	2014	Change
Regulated Gas Customers (in thousands)			
Residential	119	117	2
Commercial and industrial	10	9	1
Transportation and other	—	—	—
Total Regulated Gas Customers	129	126	3

Regulated Gas Revenue decreased by $9 million primarily due to a decrease of $11 million due to a Gas Cost Rate (GCR) decrease effective November 2014, partially offset by an increase of $2 million due to higher sales primarily as a result of higher average customer usage.

Other Gas Revenue

Other Gas Revenue decreased by $6 million primarily due to lower volumes and lower average prices for off-system sales to electric generators and gas marketers.

Pepco Energy Services

Pepco Energy Services' operating revenue decreased by $42 million primarily due to:

- A decrease of $56 million in its energy savings business primarily associated with lower construction activity.
- A decrease of $10 million from its thermal business in Atlantic City primarily due to the loss of a customer in 2015.
- An increase of $24 million in underground transmission and distribution 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:

	2015	2014	Change
Power Delivery	$1,651	$1,618	$ 33
Pepco Energy Services	132	165	(33)
Corporate and Other	(1)	—	(1)
Total	$1,782	$1,783	$ (1)

Power Delivery

Power Delivery's Fuel and Purchased Energy expense 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. Power Delivery's Fuel and Purchased Energy expense increased by $33 million primarily due to:

- An increase of $51 million primarily due to customer migration from competitive suppliers.
- An increase of $40 million due to higher electricity sales primarily as a result of warmer weather during the second and third quarters of 2015, as compared to 2014.
- An increase of $7 million from the settlement of financial hedges entered into as part of DPL's hedge program for the purchase of regulated natural gas.

The aggregate amount of these increases was partially offset by:

- A decrease of $34 million due to lower average electricity costs under Default Electricity Supply contracts.
- A decrease of $16 million in the cost of gas purchases for on-system sales as a result of lower prices.
- A decrease of $9 million in deferred electricity expense primarily due to lower revenue associated with Pepco and DPL Default Electricity Supply sales, which resulted in a lower rate of recovery of Default Electricity Supply costs.
- A decrease of $5 million in the cost of gas purchases for off-system sales as a result of lower volumes and lower average prices.
- A decrease of $3 million due to renewable energy credits in Delaware (which is offset by a corresponding decrease in Regulated T&D Electric Revenue).

Pepco Energy Services

Pepco Energy Services' Fuel and Purchased Energy expense and Other Services Cost of Sales decreased by $33 million primarily due to:

- A decrease of $50 million in its energy savings business primarily associated with decreased construction activity.
- A decrease of $5 million in its thermal business primarily due to lower natural gas prices and the loss of a customer in Atlantic City.
- An increase of $22 million associated with increased underground transmission and distribution construction activities.

Other Operation and Maintenance

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

	2015	2014	Change
Power Delivery	$772	$667	$ 105
Pepco Energy Services	36	38	(2)
Corporate and Other	(36)	(26)	(10)
Total	$772	$679	$ 93

Power Delivery

Other Operation and Maintenance expense for Power Delivery increased by $105 million primarily due to:

- An increase of $38 million due to implementation and support costs related to a new customer information system.
- An increase of $19 million associated with higher tree trimming and system maintenance costs.
- An increase of $9 million in bad debt expense, of which $5 million is deferred and recoverable.
- An increase of $8 million in internal and external Merger-related integration costs.
- An increase of $6 million in customer service costs.
- An increase of $6 million in environmental remediation costs.
- An increase of $4 million due to higher capitalized labor in 2014.
- An increase of $3 million due to the 2014 deferral of distribution rate case costs previously charged to Other Operation and Maintenance expense. The deferral was recorded in accordance with the DCPSC rate order issued in March 2014 authorizing the recovery of these costs.
- An increase of $2 million primarily due to an increase in incremental storm costs related to a severe storm with damaging winds and heavy rains on June 23, 2015 in the respective service territories of DPL and ACE. The storm resulted in widespread customer outages in each of these service territories and caused damage to the electric transmission and distribution systems of each utility. Total incremental storm restoration costs incurred by PHI for the storm through September 30, 2015 were $39 million, with $15 million incurred for repair work and $24 million incurred as capital expenditures. Costs incurred for repair work of $13 million were deferred as regulatory assets to reflect the probable recovery of these costs in Maryland and New Jersey, and $2 million was charged to Other Operation and Maintenance expense. As of September 30, 2015, the total incremental storm restoration costs associated with the June 23, 2015 storm included $10 million of estimated costs for unbilled restoration services provided by certain outside contractors. Actual costs for these services may vary from the estimates. DPL and ACE intend to pursue recovery of these incremental storm restoration costs in their respective jurisdictions in their next electric distribution base rate cases.

The increased costs referred to above for implementation and support of a new customer information system, system maintenance, customer service and storm restoration each involve internal labor costs which reflect a higher level of pension benefit cost in 2015, as compared to 2014.

Pepco Energy Services

Other Operation and Maintenance expense for Pepco Energy Services decreased by $2 million primarily due to:

- A decrease of $2 million associated with a bad debt expense recorded in 2014 for an account receivable from a customer in Atlantic City.
- A decrease of $2 million from lower demolition costs at its Benning Road generation facility.
- An increase of $2 million associated with administrative expenses in its energy savings business and higher operating expenses in its underground transmission and distribution construction business.

Corporate and Other

Other Operation and Maintenance expense for Corporate and Other decreased by $10 million primarily due to lower internal and external Merger-related transaction costs during 2015, as compared to 2014.

Depreciation and Amortization

Depreciation and Amortization expense increased by $84 million to $494 million in 2015 from $410 million in 2014 primarily due to:

- An increase of $39 million in amortization of regulatory assets primarily associated with EmPower Maryland surcharge rate increases effective February 2014 and 2015 (which is offset by an increase in Regulated T&D Electric Revenue).
- An increase of $17 million due to utility plant additions.
- An increase of $15 million in amortization of stranded costs primarily as the result of higher revenue due to a net increase effective October 2014 for the ACE Market Transition Charge tax (partially offset in Default Electricity Supply Revenue).
- An increase of $7 million in amortization of software, primarily related to the implementation of a new customer information system.
- An increase of $5 million in the Delaware Renewable Energy Portfolio Standards deferral (which is substantially offset by a corresponding increase in Regulated T&D Electric Revenue).

Other Taxes

Other Taxes increased by $12 million to $327 million in 2015 from $315 million in 2014. The increase was primarily due to:

- An increase of $7 million in property taxes.
- An increase of $5 million in utility taxes that are collected and passed through by Power Delivery (substantially offset by a corresponding increase 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 costs incurred by ACE related to the New Jersey Societal Benefit Program. The cost of electricity purchased is reported under Fuel and Purchased Energy expense and the corresponding revenue is reported under Default Electricity Supply Revenue. The costs of the New Jersey Societal Benefit Program are 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 $4 million to an expense of $34 million in 2015 as compared to an expense of $30 million in 2014 primarily due to an increase in deferred electricity expense as a result of higher Default Electricity Supply revenue rates.

Impairment Loss

PHI's operating expenses for the nine months ended September 30, 2014, include an impairment loss of $53 million ($32 million after-tax) at Pepco Energy Services associated with its combined heat and power thermal generating plant and operation assets in Atlantic City.

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $3 million to a net expense of $161 million in 2015 from a net expense of $158 million in 2014 primarily due to:

- An increase of $9 million related to gains recorded in 2014 associated with condemnation awards of certain Pepco transmission property.
- An increase of $9 million in interest expense primarily associated with higher long-term debt and higher short-term debt.
- An increase of $15 million in income due to a change in the fair value of the derivative related to the Preferred Stock.

Income Tax Expense

PHI’s income tax expense decreased by $19 million to $106 million in 2015 from $125 million in 2014. PHI’s consolidated effective income tax rates for the nine months ended September 30, 2015 and 2014 were 35.0% and 37.6%, respectively.

The decrease in the effective tax rate primarily resulted from an increase in asset removal costs, an increase in tax benefits recorded in 2015 related to certain energy efficiency-related tax deductions associated with Pepco Energy Services’ energy savings performance contracting services and a decrease in Merger-related costs (which are not tax-deductible).

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, 2015, PHI’s current assets on a consolidated basis totaled $1.5 billion and its consolidated current liabilities totaled $2.3 billion, resulting in a working capital deficit of $794 million. PHI expects the working capital deficit at September 30, 2015 to be funded during 2015 in part through cash flows from operations and from the issuance of short-term and long-term debt. At December 31, 2014, PHI’s current assets on a consolidated basis totaled $1.1 billion and its consolidated current liabilities totaled $2.1 billion, for a working capital deficit of $981 million. The decrease of $187 million in the working capital deficit from December 31, 2014 to September 30, 2015 was primarily due to an increase in cash, accounts receivable and prepaid expenses, a decrease in the current portion of long-term debt and project funding, partially offset by an increase in short-term debt.

At September 30, 2015, PHI’s consolidated cash and cash equivalents totaled $271 million, which consisted of cash and uncollected funds but excluded current Restricted cash equivalents (cash that is available to be used only for designated purposes) that totaled $18 million. The balance of consolidated cash and cash equivalents at September 30, 2015 includes $250 million held in anticipation of a $250 million PHI debt maturity on October 1, 2015. At December 31, 2014, PHI’s consolidated cash and cash equivalents totaled $14 million, which consisted of cash and uncollected funds but excluded current Restricted cash equivalents that totaled $25 million.

A detail of PHI's short-term debt balance and current maturities of long-term debt and project funding balance is as follows:

Type	As of September 30, 2015						
	PHI Parent	Pepco	DPL	ACE	ACE Funding	Pepco Energy Services	PHI Consolidated
	(millions of dollars)						
Variable Rate Demand Bonds	$ —	$ —	$ 105	$ —	$ —	$ —	$ 105
Commercial Paper	384	48	66	225	—	—	723
Term Loan	300	—	—	—	—	—	300
Total Short-Term Debt	$ 684	$ 48	$ 171	$ 225	$ —	$ —	$ 1,128
Current Portion of Long-Term Debt and Project Funding	$ 250	$ —	$ —	$ 2	$ 46	$ 2	$ 300

Type	As of December 31, 2014						
	PHI Parent	Pepco	DPL	ACE	ACE Funding	Pepco Energy Services	PHI Consolidated
	(millions of dollars)						
Variable Rate Demand Bonds	$ —	$ —	$ 105	$ —	$ —	$ —	$ 105
Commercial Paper	287	104	106	127	—	—	624
Total Short-Term Debt	$ 287	$ 104	$ 211	$ 127	$ —	$ —	$ 729
Current Portion of Long-Term Debt and Project Funding	$ 250	$ 12	$ 100	$ 15	$ 44	$ 10	$ 431

Commercial Paper

PHI, Pepco, DPL and ACE maintain on-going commercial paper programs to address short-term liquidity needs. As of September 30, 2015, the maximum capacity available under these programs was $875 million, $500 million, $500 million and $350 million, respectively, subject to available borrowing capacity under the credit facility.

PHI, Pepco, DPL and ACE had $384 million, $48 million, $66 million and $225 million, respectively, of commercial paper outstanding at September 30, 2015. The weighted average interest rate for commercial paper issued by PHI, Pepco, DPL and ACE during the nine months ended September 30, 2015 was 0.76%, 0.43%, 0.46% and 0.46%, respectively. The weighted average maturity of all commercial paper issued by PHI, Pepco, DPL and ACE during the nine months ended September 30, 2015 was ten, five, three and six days, respectively.

Financing Activity During the Three Months Ended September 30, 2015

PHI Term Loan Agreement

On July 30, 2015, PHI entered into a $300 million term loan agreement, pursuant to which PHI borrowed $300 million at a rate of interest equal to the prevailing Eurodollar rate, which is determined by reference to the London Interbank Offered Rate with respect to the relevant interest period, all as defined in the loan agreement, plus a margin of 0.95%. PHI used the net proceeds of the loan under the loan agreement to repay a portion of its outstanding commercial paper, and for general corporate purposes. All indebtedness incurred under the loan agreement is 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 July 28, 2016. Pursuant to the term loan agreement, PHI may consummate the Merger and the subsequent conversion of PHI from a Delaware corporation to a Delaware limited liability company, provided that the Merger and subsequent conversion are consummated on or before October 29, 2015. PHI has requested the consent of the lenders under the term loan to allow for completion of the Merger by June 30, 2016.

Bond Payments

In July 2015, ACE Funding made the final principal payment of $1 million on its Series 2002-1 Bonds, Class A-3, and principal payments of $6 million on its Series 2002-1 Bonds, Class A-4 and $3 million on its Series 2003-1 Bonds, Class A-3.

Bond Retirements

In August 2015, ACE retired at maturity, $15 million of its secured medium-term notes series C.

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, 2013, as permitted under the existing terms of the credit agreement, a request by PHI, Pepco, DPL and ACE to extend the credit facility termination date to August 1, 2018 was approved. All of the terms and conditions as well as pricing remained 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, $200 million, $250 million and $300 million for PHI, Pepco, DPL and ACE, respectively. 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.

Credit Facility Amendment

On May 20, 2014, PHI, Pepco, DPL and ACE entered into an amendment of and consent with respect to the credit agreement (the Consent). PHI was required to obtain the consent of certain of the lenders under the credit facility in order to permit the consummation of the Merger. Pursuant to the Consent, certain of the lenders consented to the consummation of the Merger and the subsequent conversion of PHI from a Delaware corporation to a Delaware limited liability company, provided that the Merger and subsequent conversion are consummated on or before October 29, 2015. In addition, the Consent amends the definition of “Change in Control” in the credit agreement to mean, following consummation of the Merger, an event or series of events by which Exelon no longer owns, directly or indirectly, 100% of the outstanding shares of voting stock of Pepco Holdings. PHI has requested an extension of the Consent to allow for completion of the Merger by June 30, 2016.

Sale of Receivables

On September 28, 2015, Pepco, as seller, entered into a purchase agreement with a buyer to sell receivables from an energy savings project over a period of time pursuant to a task order. The purchase price to be received by Pepco is $5 million. Pursuant to the purchase agreement, following acceptance of the energy savings project by the buyer, the buyer is entitled to receive the contract payments under the task order payable by the customer over approximately 15 years. The energy savings project will be performed by Pepco Energy Services and is expected to be completed by the end of 2017.

During 2014, Pepco, as seller, entered into a purchase agreement with a buyer to sell receivables from an energy savings project pursuant to a task order entered into under a General Services Administration area-wide agreement. The purchase price received by Pepco was $12 million. The energy savings project was performed by Pepco Energy Services and was completed in 2014. Pursuant to the purchase agreement, following acceptance of the energy savings project by the buyer, the buyer was entitled to receive the contract payments under the task order payable by the buyer over approximately 9 years. The energy savings project was accepted during the first quarter of 2015 and the amount was removed from the Current portion of long-term debt and project funding.

On October 24, 2013, Pepco Energy Services, as seller, entered into a purchase agreement with a buyer to sell receivables from an energy savings project over a period of time pursuant to a task order. The purchase price received by Pepco Energy Services was $7 million. Pursuant to the purchase agreement, following acceptance of the energy savings project by the buyer, the buyer is entitled to receive the contract payments under the task order payable by the customer over approximately 23 years. The energy savings project was accepted during the first quarter of 2015 and the amount was removed from the Current portion of long-term debt and project funding.

Cash and Credit Facility Available as of September 30, 2015

	Consolidated PHI	PHI Parent	Utility Subsidiaries
		(millions of dollars)	
Credit Facility (Total Capacity)	$ 1,500	$ 750	$ 750
Less: Letters of Credit issued	1	1	—
Commercial Paper outstanding	723	384	339
Remaining Credit Facility Available	776	365	411
Cash Invested in Money Market Funds (a)	253	251	2
Total Cash and Credit Facility Available	$ 1,029	$ 616	$ 413

(a) Cash and cash equivalents reported on the PHI consolidated balance sheet totaled $271 million, of which $253 million was invested in money market funds, and the balance was held in cash and uncollected funds. The cash invested in money market funds was held in anticipation of a $250 million PHI debt maturity on October 1, 2015.

Financing Activities Subsequent to September 30, 2015

Bond Payments

In October 2015, ACE Funding made the principal payments of $9 million on its Series 2002-1 Bonds, Class A-4 and $3 million on its Series 2003-1 Bonds, Class A-3.

Bond Retirements

In October 2015, PHI repaid at maturity $250 million of its 2.70% notes due October 1, 2015.

Pension and Postretirement Benefit Plans

PHI sponsors a non-contributory, defined benefit pension plan (the PHI Retirement Plan) that covers substantially all employees of Pepco, DPL and ACE and certain employees of other PHI subsidiaries. PHI also provides supplemental retirement benefits to certain eligible executive and key employees through nonqualified retirement plans. 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, as modified by subsequent legislation.

Under the Pension Protection Act, if a plan incurs a funding shortfall in the preceding plan year, there can be required minimum quarterly contributions in the current and following plan years. In 2015, PHI, Pepco, DPL and ACE do not expect to make discretionary tax-deductible contributions to the PHI Retirement Plan. Management expects that the current balance of the PHI Retirement Plan assets is at least equal to the funding target liability for 2015 under the Pension Protection Act. During 2014, PHI, Pepco, DPL and ACE made no discretionary tax-deductible contributions to the PHI Retirement Plan. PHI satisfied the minimum required contribution rules under the Pension Protection Act in 2014. For additional discussion of PHI's Pension and Other Postretirement Benefits, see Note (8), "Pension and Other Postretirement Benefits," to the consolidated financial statements of PHI.

PHI provides certain postretirement health care and life insurance benefits for eligible retired employees. Most employees hired after January 1, 2005 or later will not have company subsidized retiree health care coverage; however, they will be able to purchase coverage at full cost through PHI.

Based on the results of the 2014 actuarial valuation, PHI's net periodic pension and other postretirement benefit (OPEB) costs were approximately $58 million in 2014. The current estimate of net periodic pension and other postretirement benefit cost for 2015 is $97 million. The utility subsidiaries are responsible for substantially all of the total PHI net periodic pension and OPEB costs. PHI anticipates approximately 36% of its annual net periodic pension and OPEB costs will be capitalized in 2015.

Cash Flow Activity

PHI's cash flows for the nine months ended September 30, 2015 and 2014 are summarized below:

	Cash Source (Use)		
	2015	2014	Change
	(millions of dollars)		
Operating Activities	$ 601	$ 749	$ (148)
Investing Activities	(835)	(844)	9
Financing Activities	491	329	162
Net increase in cash and cash equivalents	$ 257	$ 234	$ 23

Operating Activities

Cash flows from operating activities during the nine months ended September 30, 2015 and 2014 are summarized below:

	Cash Source (Use)		
	2015	2014	Change
	(millions of dollars)		
Net income	$197	$207	$ (10)
Non-cash adjustments to net income	477	458	19
Changes in cash collateral related to derivative activities	4	(6)	10
Changes in other assets and liabilities	(77)	90	(167)
Net cash from operating activities	$601	$749	$ (148)

Net cash from operating activities decreased $148 million for the nine months ended September 30, 2015, compared to the same period in 2014. The decrease was primarily due to changes in other assets and liabilities of $167 million, which was primarily driven by an increase in accounts receivable. The increase in accounts receivable reflects revenue increases for the nine months ended September 30, 2015 as compared to the same period in 2014 associated with electric distribution rate increases, demand-side management programs and renewable energy programs, as well as certain changes in billing and collection processes associated with the implementation of a new customer information system in January 2015. Also contributing to the decrease was a $25 million payment made by PHI in the third quarter of 2015 to the District of Columbia for the purchase of future sponsorship rights, such as the rights expected to arise in connection with the development of certain sports and entertainment venues in the District of Columbia, including the Buzzard Point area where the District of Columbia has plans to develop a major league soccer stadium.

Investing Activities

Cash flows used by investing activities during the nine months ended September 30, 2015 and 2014 are summarized below:

	Cash (Use) Source		
	2015	2014	Change
	(millions of dollars)		
Investment in property, plant and equipment	$(855)	$(846)	$ (9)
DOE capital reimbursement awards received	—	4	(4)
Proceeds from sales of land	—	9	(9)
Changes in restricted cash equivalents	6	(7)	13
Net other investing activities	14	(4)	18
Net cash used by investing activities	$(835)	$(844)	$ 9

Net cash used by investing activities decreased $9 million for the nine months ended September 30, 2015, compared to the same period in 2014. The decrease was primarily due to a $13 million decrease in restricted cash equivalents related to changes in collateral received from third party suppliers for Default Electricity Supply and an increase in cash from other investing activities, primarily due to an $8 million decrease in certain deferred compensation assets, partially offset by a $9 million increase in investments in property and $9 million of proceeds from the sales of land received in 2014.

Financing Activities

Cash flows from financing activities during the nine months ended September 30, 2015 and 2014 are summarized below:

	Cash (Use) Source		
	2015	2014	Change
	(millions of dollars)		
Dividends paid on common stock	$(206)	$(204)	$ (2)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation	23	29	(6)
Issuances of Series A preferred stock	54	108	(54)
Issuances of long-term debt	408	771	(363)
Reacquisitions of long-term debt	(158)	(232)	74
Issuances (repayments) of short-term debt, net	99	(32)	131
Borrowings under term loan	300	—	300
Repayment of term loan	—	(100)	100
Cost of issuances	(6)	(10)	4
Net other financing activities	(23)	(1)	(22)
Net cash from financing activities	$ 491	$ 329	$ 162

Net cash from financing activities increased $162 million for the nine months ended September 30, 2015, compared to the same period in 2014. The increase was primarily due to a $131 million increase in short-term debt issuances, net of repayments, a $300 million term loan borrowing in 2015 and a $100 million term loan repayment in 2014, partially offset by a $289 million decrease in long-term debt issuances, net of reacquisitions, and a $54 million decrease in issuances of Series A preferred stock.

Changes in Outstanding Long-Term Debt

Cash flows from issuances and reacquisitions of long-term debt for the nine months ended September 30, 2015 and 2014 are summarized below:

	Issuances 2015	Issuances 2014
	(millions of dollars)	
Pepco		
3.60% First mortgage bonds due 2024	$ —	$ 400
4.15% First mortgage bonds due 2043	208	—
Project Funding Debt	—	10
	208	410
DPL		
3.50% First mortgage bonds due 2023	—	204
4.15% First mortgage bonds due 2045	200	—
	200	204
ACE		
3.375% First mortgage bonds due 2024	—	150
	—	150
PES		
Project Funding Debt	—	7
	—	7
	$ 408	$ 771

	Reacquisitions 2015	Reacquisitions 2014
	(millions of dollars)	
Pepco		
Project Funding Debt	$ 12	$ —
4.65% First mortgage bonds due 2014	—	175
	12	175
DPL		
5.00% Unsecured notes due 2015	100	—
	100	—
ACE		
Securitization bonds due 2014-2015	31	29
7.68% First mortgage bonds due 2015	15	—
7.63% Medium-term notes due 2014	—	7
	46	36
PCI		
6.59% - 6.69% Recourse Debt	—	11
	—	11
PES		
Project Funding Debt	—	10
	—	10
	$ 158	$ 232

<u>Changes in Short-Term Debt</u>

As of September 30, 2015, PHI had a total of $723 million of commercial paper outstanding as compared to $624 million of commercial paper outstanding as of December 31, 2014.

<u>Capital Requirements</u>

Capital Expenditures

Pepco Holdings' capital expenditures for the nine months ended September 30, 2015 were $855 million, of which $374 million was incurred by Pepco, $246 million was incurred by DPL, $212 million was incurred by ACE, $2 million was incurred by Pepco Energy Services and $21 million was incurred by Corporate and Other. The Power Delivery expenditures were primarily related to capital costs associated with distribution and transmission services. 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.

In its 2014 Form 10-K, PHI presented its projected capital expenditures for the five-year period 2015 through 2019, which reflected aggregate expenditures of $6,658 million. Projected capital expenditures include expenditures for distribution, transmission and gas delivery which primarily relate to facility replacements and upgrades to accommodate customer growth and service reliability, including capital expenditures for continuing reliability enhancement efforts. These projected capital expenditures also include expenditures for the smart grid programs undertaken by each of PHI's utility subsidiaries to install smart meters, further automate their electric distribution systems and enhance their communications infrastructure.

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 total $168 million in DOE awards, $130 million was offset against smart grid-related capital expenditures of Pepco and ACE. The remaining $38 million is being used to offset incremental expenditures associated with direct load control and other Pepco and ACE programs, which have been deferred as regulatory assets. As of September 30, 2015, Pepco and ACE have received all of their DOE award payments.

The IRS announced that, to the extent these grants are expended on capital items, they would not be considered taxable income.

Guarantees, Indemnifications, Obligations 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.

PHI guarantees the obligations of Pepco Energy Services under certain contracts in its energy savings performance contracting business and underground transmission and distribution construction business. At September 30, 2015, PHI's guarantees of Pepco Energy Services' obligations under these contracts totaled $259 million. PHI also guarantees the obligations of Pepco Energy Services under surety bonds obtained by Pepco Energy Services for construction projects. These guarantees totaled $167 million at September 30, 2015.

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 $64 million at September 30, 2015.

For additional discussion of PHI's third party guarantees, indemnifications, obligations and off-balance sheet arrangements, see Note (15), "Commitments and Contingencies – Third Party Guarantees, Indemnifications, and Off-Balance Sheet Arrangements," to the consolidated financial statements of PHI.

Dividends

On October 22, 2015, Pepco Holdings' Board of Directors declared a dividend of $0.27 per share, payable December 31, 2015 to holders of common stock of record on the close of business on December 10, 2015.

On October 22, 2015, Pepco Holdings' Board of Directors also declared a pro-rata dividend in the event the Merger is completed before the close of business on December 10, 2015. The pro-rata dividend is payable 20 days after the Merger is completed to holders of common stock of record as of the day immediately prior to the day the Merger is completed, at a rate of $0.002967 per share per day beginning September 11, 2015, and ending the day before the Merger is completed.

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, 2015, 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 $36 million. This amount is attributable primarily to project financing for 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

Rate Proceedings

Distribution

The rates that each of Pepco, DPL and ACE is permitted to charge for the retail distribution of electricity and natural gas to its various classes of customers are based on the principle that the utility is entitled to generate an amount of revenue sufficient to recover the cost of providing the service, including a reasonable rate of return on its invested capital. These "base rates" are intended to cover all of each utility's reasonable and prudent expenses of constructing, operating and maintaining its distribution facilities (other than costs covered by specific cost-recovery surcharges).

A change in base rates in a jurisdiction requires the approval of the public service commission. In the rate application submitted to the public service commission, the utility specifies an increase in its “revenue requirement,” which is the additional revenue that the utility is seeking authorization to earn. The “revenue requirement” consists of (i) the allowable expenses incurred by the utility, including operation and maintenance expenses, taxes and depreciation, and (ii) the utility’s cost of capital. The compensation of the utility for its cost of capital takes the form of an overall “rate of return” allowed by the public service commission on the utility’s distribution “rate base” to compensate the utility’s investors for their debt and equity investments in the company. The rate base is the aggregate value of the investment in property used by the utility in providing electricity and natural gas distribution services and generally consists of plant in service net of accumulated depreciation and accumulated deferred taxes, plus cash working capital, material and operating supplies and, depending on the jurisdiction, construction work in progress. Over time, the rate base is increased by utility property additions and reduced by depreciation and property retirements and write-offs.

In addition to its base rates, some of the costs of providing distribution service are recovered through the operation of surcharges. Examples of costs recovered by PHI’s utility subsidiaries through surcharges, which vary depending on the jurisdiction, include: a surcharge to reimburse the utility for the cost of purchasing electricity from NUGs (New Jersey); surcharges to reimburse the utility for costs of public interest programs for low income customers and for demand-side management programs (New Jersey, Maryland, Delaware and the District of Columbia); a surcharge to pay the Transitional Bond Charge (New Jersey); surcharges to reimburse the utility for certain environmental costs (Delaware and Maryland); and surcharges related to the BSA (Maryland and the District of Columbia). Each utility subsidiary regularly reviews its distribution rates in each jurisdiction of its service territory, and files applications to adjust its rates as necessary in an effort to ensure that its revenues are sufficient to cover its operating expenses and its cost of capital. The timing of future rate filings and the change in the distribution rate requested will depend on a number of factors, including changes in revenues and expenses and the incurrence or the planned incurrence of capital expenditures.

As further described in the “Management’s Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Agreement and Plan of Merger with Exelon Corporation,” PHI has entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, PHI and its subsidiaries may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than concluding pending filings.

In general, a request for new distribution rates is made on the basis of “test year” balances for rate base allowable operating expenses and a requested rate of return. The test year amounts used in the filing may be historical or partially projected. The public service commission may, however, select a different test period than that proposed by the applicable utility. Although the approved tariff rates are intended to be forward-looking, and therefore provide for the recovery of some future changes in rate base and operating costs, they typically do not reflect all of the changes in costs for the period in which the new rates are in effect. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Mitigation of Regulatory Lag.”

The following table shows, for each of the PHI utility subsidiaries, the authorized return on equity as determined in the most recently concluded base rate proceeding and the effective date of the authorized return:

	Authorized Return on Equity	Rate Effective Date
Pepco:		
District of Columbia (electricity)	9.40%	April 2014
Maryland (electricity)	9.62%	July 2014
DPL:		
Delaware (electricity)	9.70%	May 2014 (a)
Maryland (electricity)	9.81% (b)	September 2013
Delaware (natural gas)	9.75% (c)	November 2013
ACE:		
New Jersey (electricity)	9.75%	September 2014

(a) Beginning in September 2014, DPL provided credits or refunds to any customer whose rates were increased in October 2013 in excess of the increase approved by the DPSC in April 2014.
(b) ROE has not been determined by any proceeding and is specified only for the purposes of calculating the allowance for funds used during construction (AFUDC) and regulatory asset carrying costs.
(c) ROE has not been determined by any proceeding and is specified only for reporting purposes and for calculating the AFUDC, construction work in progress, regulatory asset carrying costs and other accounting metrics.

Transmission

The rates Pepco, DPL and ACE are permitted to charge for the transmission of electricity are regulated by FERC and are based on each utility's transmission rate base, transmission operating expenses and an overall rate of return that is approved by FERC. For each utility subsidiary, FERC has approved a formula for the calculation of the utility transmission rate, which is referred to as a "formula rate." The formula rates include both fixed and variable elements. Certain of the fixed elements, such as the return on equity and depreciation rates, can be changed only in a FERC transmission rate proceeding. The variable elements of the formula, including the utility's rate base and operating expenses, are updated annually, effective June 1 of each year, with data from the utility's most recent annual FERC Form 1 filing.

In addition to its formula rate, each utility's return on equity is supplemented by incentive rates, sometimes referred to as "adders," and other incentives, which are authorized by FERC to promote capital investment in transmission infrastructure. 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. The 10.8% base ROE for facilities placed into service prior to 2006 receives a 50-basis-point incentive adder for being a member of a regional transmission organization. In addition, ROE adders are in effect for each of Pepco, DPL and ACE relating to specific transmission upgrades and improvements. As members of PJM, the transmission rates of Pepco, DPL and ACE are set out in PJM's Open Access Transmission Tariff. See Note (7), "Regulatory Matters – Rate Proceedings – FERC Transmission ROE Challenges," to the consolidated financial statements of PHI, regarding certain challenges to Pepco's, DPL's and ACE's base ROE.

For a discussion of pending state public utility commission and FERC transmission rate and other rate proceedings, see Note (7), "Regulatory Matters – Rate Proceedings," to the consolidated financial statements of PHI.

Legal Proceedings and Regulatory Matters

For a discussion of legal proceedings, see Note (15), “Commitments and Contingencies,” to the consolidated financial statements of PHI, and for a discussion of regulatory matters, see Note (7), “Regulatory Matters,” 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’ 2014 Form 10-K. There have been no material changes to PHI’s critical accounting policies as disclosed in the 2014 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 major 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, as of September 30, 2015, had a population of approximately 2.3 million. As of September 30, 2015, 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.

Agreement and Plan of Merger with Exelon Corporation

PHI has entered into the Merger Agreement with Exelon and Merger Sub, providing for the Merger, with PHI surviving the Merger as an indirect, wholly owned subsidiary of Exelon. For additional information regarding the Merger, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Agreement and Plan of Merger with Exelon Corporation."

Utility Capital Expenditures

Pepco allocates a substantial portion of its total capital expenditures to improving the reliability of its electrical transmission and distribution systems and replacing aging infrastructure throughout its service territories. These activities include one or more of the following:

- Identifying and upgrading under-performing feeder lines;
- Adding new facilities to support load;
- Installing distribution automation systems on both the overhead and underground network systems; and
- Rejuvenating and replacing underground residential cables.

Smart Grid

Pepco is building a "smart grid" which is designed to meet the challenges of rising energy costs, improve service reliability of the energy distribution system, 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 Initiatives."

District of Columbia Power Line Undergrounding Initiative

For information about the District of Columbia Power Line Undergrounding Initiative, please refer to Note (6), "Regulatory Matters – District of Columbia Power Line Undergrounding Initiative," to the financial statements of Pepco.

Mitigation of Regulatory Lag

An important factor in the ability of Pepco to earn its authorized ROE is the willingness of the DCPSC and the MPSC to adequately address the shortfall in revenues in Pepco's rate structure 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 investments in rate base and operating expenses are increasing more rapidly than revenue growth. For a more detailed discussion of regulatory lag, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Mitigation of Regulatory Lag."

In an effort to minimize the effects of regulatory lag, prior to the initial execution of the Merger Agreement in April 2014, Pepco had been filing electric distribution base rate cases every nine to twelve months in each of its jurisdictions, pursuing alternative ratemaking mechanisms, evaluating potential reductions in planned capital expenditures, and discussing with the regulatory community and other stakeholders the changing regulatory model economics that are causing regulatory lag.

As further described in PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Agreement and Plan of Merger with Exelon Corporation," PHI has entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, Pepco may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than concluding pending filings. To date, Pepco has not requested such consent from Exelon and accordingly, no new distribution base rate cases have been filed since entering into the Merger Agreement. Accordingly, Pepco's efforts to mitigate regulatory lag have been delayed pending the closing of the Merger or the termination of the Merger Agreement.

Transmission ROE Challenges

For information about the challenges to Pepco's base ROE and the application of the formula rate process, each associated with the transmission services it provides, please refer to Note (6), "Regulatory Matters – Rate Proceedings – FERC Transmission ROE Challenges," to the financial statements of Pepco.

Nine Months Ended September 30, 2015 Compared to the Nine Months Ended September 30, 2014

Pepco's net income for the nine months ended September 30, 2015 was $128 million compared to $145 million for the nine months ended September 30, 2014. The $17 million decrease in earnings was primarily due to the following:

- A decrease of $22 million due to higher operation and maintenance expense primarily related to the implementation of a new customer information system, higher tree trimming and system maintenance costs, higher environmental remediation costs, previously expensed District of Columbia rate case costs established as a regulatory asset in 2014 and higher employee related expenses.
- A decrease of $5 million in other income related to gains recorded in 2014 associated with condemnation awards for certain transmission property.
- A decrease of $5 million due to higher depreciation and amortization expense associated with regulatory assets and increases in plant investment.
- A decrease of $3 million primarily due to higher long-term debt interest expense and higher property taxes.
- An increase of $12 million from electric distribution base rate increases in the District of Columbia and in Maryland.
- An increase of $5 million due to customer growth in 2015, primarily in the residential class.

Results of Operations

The following results of operations discussion compares the nine months ended September 30, 2015 to the nine months ended September 30, 2014. All amounts in the tables (except sales and customers) are in millions of dollars.

A condensed summary of Pepco's statement of income for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014, is set forth in the table below:

	2015	2014	Change
Operating revenue	$1,686	$1,630	$ 56
Purchased energy	606	612	(6)
Other operation and maintenance	328	287	41
Depreciation and amortization	207	171	36
Other taxes	284	275	9
Total operating expenses	1,425	1,345	80
Operating income	261	285	(24)
Other income (expenses)	(71)	(58)	(13)
Income before income tax expense	190	227	(37)
Income tax expense	62	82	(20)
Net income	$ 128	$ 145	$ (17)

Operating Revenue

	2015	2014	Change
Regulated T&D Electric Revenue	$1,033	$ 972	$ 61
Default Electricity Supply Revenue	627	634	(7)
Other Electric Revenue	26	24	2
Total Operating Revenue	$1,686	$1,630	$ 56

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 territories 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 in consideration for approved regional transmission expansion plan expenditures.

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 includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated T&D Electric

	2015	2014	Change
Regulated T&D Electric Revenue			
Residential	$ 338	$ 293	$ 45
Commercial and industrial	553	536	17
Transmission and other	142	143	(1)
Total Regulated T&D Electric Revenue	$ 1,033	$ 972	$ 61

	2015	2014	Change
Regulated T&D Electric Sales (GWh)			
Residential	6,844	6,158	686
Commercial and industrial	13,347	13,457	(110)
Transmission and other	102	113	(11)
Total Regulated T&D Electric Sales	20,293	19,728	565

	2015	2014	Change
Regulated T&D Electric Customers (in thousands)			
Residential	750	729	21
Commercial and industrial	74	74	—
Transmission and other	—	—	—
Total Regulated T&D Electric Customers	824	803	21

Regulated T&D Electric Revenue increased by $61 million primarily due to:

- An increase of $30 million due to EmPower Maryland rate increases effective February 2014 and 2015 (which is substantially offset by a corresponding increase in Depreciation and Amortization).
- An increase of $19 million due to electric distribution base rate increases in the District of Columbia effective April 2014 and in Maryland effective July 2014.
- An increase of $8 million due to customer growth in 2015, primarily in the residential class.
- An increase of $4 million in capacity revenue as a result of expanding Maryland demand side management programs (which is partially offset in Depreciation and Amortization).

The aggregate amount of these increases was partially offset by a decrease of $3 million in transmission revenue due to the establishment of a reserve related to the FERC ROE challenges, partially offset by higher rates effective June 1, 2014 and June 1, 2015 related to increases in transmission plant investment and operating expenses.

Default Electricity Supply

	2015	2014	Change
Default Electricity Supply Revenue			
Residential	$ 444	$ 420	$ 24
Commercial and industrial	167	200	(33)
Other	16	14	2
Total Default Electricity Supply Revenue	$ 627	$ 634	$ (7)

	2015	2014	Change
Default Electricity Supply Sales (GWh)			
Residential	5,258	4,705	553
Commercial and industrial	2,058	2,336	(278)
Other	3	5	(2)
Total Default Electricity Supply Sales	7,319	7,046	273

	2015	2014	Change
Default Electricity Supply Customers (in thousands)			
Residential	620	576	44
Commercial and industrial	45	45	—
Other	—	—	—
Total Default Electricity Supply Customers	665	621	44

Default Electricity Supply Revenue decreased by $7 million primarily due to:

- A decrease of $32 million as a result of lower Default Electricity Supply rates.
- A decrease of $13 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:

- An increase of $19 million in average customer usage.
- An increase of $18 million due to higher sales primarily as a result of colder weather during the first quarter and warmer weather during the second and third quarters of 2015, as compared to 2014.

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:

	2015	2014
Sales to District of Columbia customers	30%	27%
Sales to Maryland customers	41%	42%

<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 decreased by $6 million to $606 million in 2015 from $612 million in 2014 primarily due to:

- A decrease of $22 million due to lower average electricity costs under Default Electricity Supply contracts.
- A decrease of $4 million in deferred electricity expense primarily due to lower revenue associated with Default Electricity Supply sales, 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 $15 million due to higher electricity sales primarily as a result of warmer weather during the second and third quarters of 2015, as compared to 2014.
- An increase of $5 million primarily due to customer migration from competitive suppliers.

Other Operation and Maintenance

Other Operation and Maintenance expense increased by $41 million to $328 million in 2015 from $287 million in 2014 primarily due to:

- An increase of $17 million due to implementation and support costs related to a new customer information system.
- An increase of $8 million primarily associated with higher tree trimming and system maintenance costs.
- An increase of $4 million due to higher capitalized labor in 2014.
- An increase of $4 million in internal and external Merger-related integration costs.
- An increase of $3 million due to the 2014 deferral of distribution rate case costs previously charged to Other Operation and Maintenance expense. The deferral was recorded in accordance with a DCPSC rate order issued in March 2014 authorizing the recovery of these costs.
- An increase of $3 million in environmental remediation costs.
- An increase of $1 million in customer service costs.

The aggregate amount of these increases was partially offset by a $4 million decrease in emergency restoration costs.

The increased costs referred to above for implementation and support of a new customer information system, system maintenance and customer service each involve internal labor costs which reflect a higher level of pension benefit cost in 2015, as compared to 2014.

Depreciation and Amortization

Depreciation and Amortization expense increased by $36 million to $207 million in 2015 from $171 million in 2014 primarily due to:

- An increase of $28 million in amortization of regulatory assets primarily associated with EmPower Maryland surcharge rate increases effective February 2014 and 2015 (which is offset in Regulated T&D Electric Revenue).
- An increase of $8 million due to utility plant additions.

Other Taxes

Other Taxes increased by $9 million to $284 million in 2015 from $275 million in 2014. The increase was primarily due to:

- An increase of $5 million in property taxes.
- An increase of $3 million in utility taxes that are collected and passed through by Pepco (substantially offset by a corresponding increase in Regulated T&D Electric Revenue).

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $13 million to a net expense of $71 million in 2015 from a net expense of $58 million in 2014. The increase was primarily due to:

- An increase of $9 million related to gains recorded in 2014 associated with condemnation awards for certain transmission property.
- An increase of $5 million in long-term debt interest expense.
- An increase of $2 million in income related to the AFUDC that is applied to construction projects.

Income Tax Expense

Pepco's income tax expense decreased by $20 million to $62 million in 2015 from $82 million in 2014. Pepco's effective income tax rates for the nine months ended September 30, 2015 and 2014 were 32.6% and 36.1%, respectively. The decrease in the effective tax rate primarily resulted from an increase in asset removal costs.

Capital Requirements

Capital Expenditures

Pepco's capital expenditures for the nine months ended September 30, 2015 were $374 million. These expenditures were primarily related to capital costs associated with distribution and transmission services. 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 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 $41 million at September 30, 2015.

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 was offset against smart grid-related capital expenditures of Pepco. The remaining $31 million is being used to offset incremental expenditures associated with direct load control and other programs, which have been deferred as regulatory assets. As of September 30, 2015, Pepco has received all of its DOE award payments.

The IRS announced that, to the extent these grants are expended on capital items, they would 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 portions of Delaware and Maryland. DPL also provides Default Electricity Supply. DPL's electricity distribution service territory covers approximately 5,000 square miles and, as of September 30, 2015, had a population of approximately 1.4 million. As of September 30, 2015, approximately 65% of delivered electricity sales were to Delaware customers and approximately 35% 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, as of September 30, 2015, had a population of approximately 0.5 million.

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 modified fixed variable rate design, which would provide for a charge not tied to a customer's volumetric consumption of electricity or natural gas, has been proposed for DPL electricity and natural gas customers in Delaware. 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.

Agreement and Plan of Merger with Exelon Corporation

PHI has entered into the Merger Agreement with Exelon and Merger Sub, providing for the Merger, with PHI surviving the Merger as an indirect, wholly owned subsidiary of Exelon. For additional information regarding the Merger, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Agreement and Plan of Merger with Exelon Corporation."

Utility Capital Expenditures

DPL allocates a substantial portion of its total capital expenditures to improving the reliability of its electrical transmission and distribution systems and replacing aging infrastructure throughout its service territories. These activities include one or more of the following:

- Identifying and upgrading under-performing feeders;
- Adding new facilities to support load;
- Installing distribution automation systems on both the overhead and underground network systems; and
- Rejuvenating and replacing underground residential cables.

Smart Grid

DPL is building a smart grid which is designed to meet the challenges of rising energy costs, improve service reliability of the energy distribution system, 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 Initiatives."

Mitigation of Regulatory Lag

An important factor in the ability of DPL to earn its authorized ROE is the willingness of the DPSC and the MPSC to adequately address the shortfall in revenues in DPL's rate structure 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 investments in rate base and operating expenses are increasing more rapidly than revenue growth. For a more detailed discussion of regulatory lag, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Mitigation of Regulatory Lag."

In an effort to minimize the effects of regulatory lag, prior to the initial execution of the Merger Agreement in April 2014, DPL had been filing electric distribution base rate cases every nine to twelve months in each of its jurisdictions, pursuing alternative ratemaking mechanisms, evaluating potential reductions in planned capital expenditures, and discussing with the regulatory community and other stakeholders the changing regulatory model economics that are causing regulatory lag.

As further described in PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Agreement and Plan of Merger with Exelon Corporation," PHI has entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, DPL may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than concluding pending filings. To date, DPL has not requested such consent from Exelon and accordingly, no new distribution base rate cases have been filed since entering into the Merger Agreement. Accordingly, DPL's efforts to mitigate regulatory lag have been delayed pending the closing of the Merger or the termination of the Merger Agreement.

Transmission ROE Challenges

For information about the challenges to DPL's base ROE and the application of the formula rate process, each associated with the transmission services it provides, please refer to Note (7), "Regulatory Matters – Rate Proceedings – FERC Transmission ROE Challenges," to the financial statements of DPL.

Earnings Overview

Nine Months Ended September 30, 2015 Compared to the Nine Months Ended September 30, 2014

DPL's net income for the nine months ended September 30, 2015 was $55 million compared to $79 million for the nine months ended September 30, 2014. The $24 million decrease in earnings was primarily due to the following:

- A decrease of $19 million due to higher operation and maintenance expense primarily related to the implementation of a new customer information system, higher bad debt expense, higher tree trimming and system maintenance costs, higher environmental remediation costs and higher employee related expenses.
- A decrease of $4 million due to higher depreciation and amortization expense primarily resulting from increases in plant investment.
- A decrease of $2 million due to higher long-term debt interest expense and higher property taxes.
- An increase of $2 million from other distribution revenue primarily due to the effect of colder weather during the first quarter and warmer weather during the second and third quarters of 2015, as compared to 2014.

Results of Operations

The following results of operations discussion compares the nine months ended September 30, 2015 to the nine months ended September 30, 2014. All amounts in the tables (except sales and customers) are in millions of dollars.

A condensed summary of DPL's statement of income for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014, is set forth in the table below:

	2015	2014	Change
Operating revenue	$1,015	$985	$ 30
Purchased energy	444	422	22
Gas purchased	66	80	(14)
Other operation and maintenance	235	202	33
Depreciation and amortization	117	93	24
Other taxes	35	32	3
Total operating expenses	897	829	68
Operating income	118	156	(38)
Other income (expenses)	(28)	(26)	(2)
Income before income tax expense	90	130	(40)
Income tax expense	35	51	(16)
Net income	$ 55	$ 79	$ (24)

Electric Operating Revenue

	2015	2014	Change
Regulated T&D Electric Revenue	$443	$421	$ 22
Default Electricity Supply Revenue	433	408	25
Other Electric Revenue	9	11	(2)
Total Electric Operating Revenue	$885	$840	$ 45

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 in consideration for approved regional transmission expansion plan expenditures.

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 includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated T&D Electric

	2015	2014	Change
Regulated T&D Electric Revenue			
Residential	$ 202	$ 192	$ 10
Commercial and industrial	130	116	14
Transmission and other	111	113	(2)
Total Regulated T&D Electric Revenue	$ 443	$ 421	$ 22

	2015	2014	Change
Regulated T&D Electric Sales (GWh)			
Residential	4,297	4,054	243
Commercial and industrial	5,353	5,402	(49)
Transmission and other	33	36	(3)
Total Regulated T&D Electric Sales	9,683	9,492	191

	2015	2014	Change
Regulated T&D Electric Customers (in thousands)			
Residential	453	447	6
Commercial and industrial	61	60	1
Transmission and other	1	1	—
Total Regulated T&D Electric Customers	515	508	7

Regulated T&D Electric Revenue increased by $22 million primarily due to:

- An increase of $12 million due to EmPower Maryland rate increases effective February 2014 and 2015 (which is substantially offset by a corresponding increase in Depreciation and Amortization).
- An increase of $7 million due to higher sales as a result of colder weather during the first quarter and warmer weather during the second and third quarters of 2015, as compared to 2014.
- An increase of $7 million primarily due to rate increases effective June 2014 and June 2015 associated with the Renewable Portfolio Surcharge in Delaware (which is substantially offset in Fuel and Purchased Energy and Depreciation and Amortization).
- An increase of $3 million in transmission revenue resulting from higher rates effective June 1, 2014 and June 1, 2015 related to increases in transmission plant investment and operating expenses, partially offset by the establishment of a reserve related to the FERC ROE challenges.

The aggregate amount of these increases was partially offset by a decrease of $5 million in revenue related to the resale by DPL of renewable energy to PJM (which is substantially offset in Purchased Energy and Depreciation and Amortization).

Default Electricity Supply

	2015	2014	Change
Default Electricity Supply Revenue			
Residential	$ 333	$ 313	$ 20
Commercial and industrial	92	86	6
Other	8	9	(1)
Total Default Electricity Supply Revenue	$ 433	$ 408	$ 25

	2015	2014	Change
Default Electricity Supply Sales (GWh)			
Residential	3,707	3,457	250
Commercial and industrial	1,153	1,041	112
Other	18	20	(2)
Total Default Electricity Supply Sales	4,878	4,518	360

	2015	2014	Change
Default Electricity Supply Customers (in thousands)			
Residential	396	389	7
Commercial and industrial	40	39	1
Other	—	—	—
Total Default Electricity Supply Customers	436	428	8

Default Supply Revenue increased by $25 million primarily due to:

- An increase of $15 million due to higher sales primarily as a result of customer migration from competitive suppliers.
- An increase of $13 million due to higher sales as a result of colder weather during the first quarter and warmer weather during the second and third quarters of 2015, as compared to 2014.
- An increase of $3 million due to higher non-weather related average customer usage.

The aggregate amount of these increases was partially offset by a decrease of $5 million as a result of lower Default Electricity Supply rates.

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:

	2015	2014
Sales to Delaware customers	49%	45%
Sales to Maryland customers	54%	52%

Natural Gas Operating Revenue

	2015	2014	Change
Regulated Gas Revenue	$120	$129	$ (9)
Other Gas Revenue	10	16	(6)
Total Natural Gas Operating Revenue	$130	$145	$ (15)

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 consists of 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

	2015	2014	Change
Regulated Gas Revenue			
Residential	$ 73	$ 77	$ (4)
Commercial and industrial	39	44	(5)
Transportation and other	8	8	—
Total Regulated Gas Revenue	$ 120	$ 129	$ (9)

	2015	2014	Change
Regulated Gas Sales (million cubic feet)			
Residential	6,311	6,114	197
Commercial and industrial	4,409	4,285	124
Transportation and other	4,716	4,737	(21)
Total Regulated Gas Sales	15,436	15,136	300

	2015	2014	Change
Regulated Gas Customers (in thousands)			
Residential	119	117	2
Commercial and industrial	10	9	1
Transportation and other	—	—	—
Total Regulated Gas Customers	129	126	3

Regulated Gas Revenue decreased by $9 million primarily due to a decrease of $11 million due to a GCR decrease effective November 2014, partially offset by an increase of $2 million due to higher sales primarily as a result of higher average customer usage.

Other Gas Revenue

Other Gas Revenue decreased by $6 million primarily due to lower volumes and lower average prices for off-system sales to electric generators and gas marketers.

Operating Expenses

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 increased by $22 million to $444 million in 2015 from $422 million in 2014 primarily due to:

- An increase of $18 million primarily due to customer migration from competitive suppliers.
- An increase of $8 million due to higher electricity sales primarily as a result of warmer weather during the second and third quarters of 2015, as compared to 2014.
- An increase of $2 million due to higher average electricity costs under Default Electricity Supply contracts.

The aggregate amount of these increases was partially offset by:

- A decrease of $5 million in deferred electricity expense primarily due to lower Default Electricity Supply rates, which resulted in a lower rate of recovery of Default Electricity Supply costs.
- A decrease of $3 million due to renewable energy credits in Delaware (which is offset by a corresponding decrease in Regulated T&D Electric Revenue).

Gas Purchased

Gas Purchased expense 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 expense decreased by $14 million to $66 million in 2015 from $80 million in 2014 primarily due to the following:

- A decrease of $16 million in the cost of gas purchases for on-system sales as a result of lower prices.
- A decrease of $5 million in the cost of gas purchases for off-system sales as a result of lower volumes and lower average prices.

The aggregate amount of these decreases was partially offset by an increase of $7 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 increased by $33 million to $235 million in 2015 from $202 million in 2014 primarily due to:

- An increase of $10 million due to implementation and support costs related to a new customer information system.
- An increase of $6 million in bad debt expense, of which $2 million is deferred and recoverable.
- An increase of $3 million associated with higher tree trimming and system maintenance costs.
- An increase of $3 million in environmental remediation costs.
- An increase of $2 million in internal and external Merger-related integration costs.
- An increase of $2 million in customer service costs.
- An increase of $2 million primarily due to an increase in incremental storm costs related to a severe storm with damaging winds and heavy rains in DPL's Maryland jurisdiction on June 23, 2015. The storm resulted in widespread customer outages and caused damage to the electric transmission and distribution systems. Total incremental storm restoration costs incurred by DPL for the storm through September 30, 2015 were $4 million, with $2 million incurred for repair work and $2 million incurred as capital expenditures. Costs incurred for repair work of less than $1 million were deferred as regulatory assets to reflect the probable recovery of these costs in Maryland, and $2 million was charged to Other Operation and Maintenance expense. As of September 30, 2015, the total incremental storm restoration costs associated with the June 23, 2015 storm included $1 million of estimated costs for unbilled restoration services provided by certain outside contractors. Actual costs for these services may vary from the estimates. DPL intends to pursue recovery of these incremental storm restoration costs in its next electric distribution base rate cases.

The increased costs referred to above for implementation and support of a new customer information system, system maintenance, customer service and storm restoration each involve internal labor costs which reflect a higher level of pension benefit cost in 2015, as compared to 2014.

Depreciation and Amortization

Depreciation and Amortization expense increased by $24 million to $117 million in 2015 from $93 million in 2014 primarily due to:

- An increase of $11 million in amortization of regulatory assets primarily associated with EmPower Maryland surcharge rate increases effective February 2014 and 2015 (which is offset in Regulated T&D Electric Revenue).
- An increase of $6 million due to utility plant additions.
- An increase of $5 million in the Delaware Renewable Energy Portfolio Standards deferral (which is substantially offset by a corresponding increase in Regulated T&D Electric Revenue).

Other Taxes

Other Taxes increased by $3 million to $35 million in 2015 from $32 million in 2014. The increase was primarily due to:

- An increase of $2 million in property taxes.
- An increase of $1 million in utility taxes that are collected and passed through by DPL (substantially offset by a corresponding increase in Regulated T&D Electric Revenue).

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $2 million to a net expense of $28 million in 2015 from a net expense of $26 million in 2014. The increase is primarily due to a $1 million increase in long-term debt interest expense and a $1 million decrease in income related to the AFUDC that is applied to construction projects.

Income Tax Expense

DPL's income tax expense decreased by $16 million to $35 million in 2015 from $51 million in 2014. DPL's effective income tax rates for the nine months ended September 30, 2015 and 2014 were 38.9% and 39.2%, respectively.

Capital Requirements

Capital Expenditures

DPL's capital expenditures for the nine months ended September 30, 2015 were $246 million. These expenditures were primarily related to capital costs associated with distribution and transmission services. 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.

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 portions of 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, as of September 30, 2015, had 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.

Agreement and Plan of Merger with Exelon Corporation

PHI has entered into the Merger Agreement with Exelon and Merger Sub, providing for the Merger, with PHI surviving the Merger as an indirect, wholly owned subsidiary of Exelon. For additional information regarding the Merger, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Agreement and Plan of Merger with Exelon Corporation."

Utility Capital Expenditures

ACE allocates a substantial portion of its total capital expenditures to improving the reliability of its electrical transmission and distribution systems and replacing aging infrastructure throughout its service territory. These activities include one or more of the following:

- Identifying and upgrading under-performing feeders;
- Adding new facilities to support load;
- Installing distribution automation systems on both the overhead and underground network systems; and
- Rejuvenating and replacing underground residential cables.

Mitigation of Regulatory Lag

An important factor in the ability of ACE to earn its authorized ROE is the willingness of the NJBPU to adequately address the shortfall in revenues in ACE's rate structure 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." ACE is currently experiencing significant regulatory lag because investments in rate base and operating expenses are increasing more rapidly than revenue growth. For a more detailed discussion of regulatory lag, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Mitigation of Regulatory Lag."

In an effort to minimize the effects of regulatory lag, prior to the initial execution of the Merger Agreement in April 2014, ACE had been filing electric distribution base rate cases every nine to twelve months, pursuing alternative ratemaking mechanisms, evaluating potential reductions in planned capital expenditures, and discussing with the regulatory community and other stakeholders the changing regulatory model economics that are causing regulatory lag.

As further described in PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Agreement and Plan of Merger with Exelon Corporation," PHI has entered into the Merger Agreement with Exelon and Merger Sub. Subject to certain exceptions, prior to the Merger or the termination of the Merger Agreement, ACE may not, without the consent of Exelon, initiate, file or pursue any rate cases, other than concluding pending filings. To date, ACE has not requested such consent from Exelon and accordingly, no new distribution base rate cases have been filed since entering into the Merger Agreement. Accordingly, ACE's efforts to mitigate regulatory lag have been delayed pending the closing of the Merger or the termination of the Merger Agreement.

Transmission ROE Challenges

For information about the challenges to ACE's base ROE and the application of the formula rate process, each associated with the transmission services it provides, please refer to Note (6), "Regulatory Matters – Rate Proceedings – FERC Transmission ROE Challenges," to the consolidated financial statements of ACE.

Earnings Overview

Nine Months Ended September 30, 2015 Compared to the Nine Months Ended September 30, 2014

ACE's consolidated net income for the nine months ended September 30, 2015 was $28 million compared to $39 million for the nine months ended September 30, 2014. The $11 million decrease in earnings was primarily due to the following:

- A decrease of $16 million due to higher operation and maintenance expense primarily related to the implementation of a new customer information system, higher tree trimming and system maintenance costs, higher storm restoration costs and higher employee related expenses.
- A decrease of $5 million associated with ACE Basic Generation Service primarily attributable to a decrease in unbilled revenue due to lower average customer usage.
- A decrease of $2 million due to higher depreciation and amortization expense primarily resulting from increases in plant investment.
- An increase of $9 million from an electric distribution base rate increase in New Jersey.
- An increase of $5 million from other distribution revenue primarily due to the effect of warmer weather during the second and third quarters of 2015, as compared to 2014.

Results of Operations

The following results of operations discussion compares the nine months ended September 30, 2015 to the nine months ended September 30, 2014. All amounts in the tables (except sales and customers) are in millions of dollars.

A condensed summary of ACE's consolidated statement of income for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014, is set forth in the table below:

	2015	2014	Change
Operating revenue	$1,006	$940	$ 66
Purchased energy	535	504	31
Other operation and maintenance	209	178	31
Depreciation and amortization	135	117	18
Other taxes	3	3	—
Deferred electric service costs	34	30	4
Total operating expenses	916	832	84
Operating income	90	108	(18)
Other income (expenses)	(46)	(45)	(1)
Income before income tax expense	44	63	(19)
Income tax expense	16	24	(8)
Net Income	$ 28	$ 39	$ (11)

Operating Revenue

	2015	2014	Change
Regulated T&D Electric Revenue	$ 366	$343	$ 23
Default Electricity Supply Revenue	632	587	45
Other Electric Revenue	8	10	(2)
Total Operating Revenue	$1,006	$940	$ 66

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 includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated T&D Electric

	2015	2014	Change
Regulated T&D Electric Revenue			
Residential	$ 174	$ 155	$ 19
Commercial and industrial	120	116	4
Transmission and other	72	72	—
Total Regulated T&D Electric Revenue	$ 366	$ 343	$ 23

	2015	2014	Change
Regulated T&D Electric Sales (GWh)			
Residential	3,452	3,229	223
Commercial and industrial	3,665	3,737	(72)
Transmission and other	32	33	(1)
Total Regulated T&D Electric Sales	7,149	6,999	150

	2015	2014	Change
Regulated T&D Electric Customers (in thousands)			
Residential	482	480	2
Commercial and industrial	65	65	—
Transmission and other	1	1	—
Total Regulated T&D Electric Customers	548	546	2

Regulated T&D Electric Revenue increased by $23 million primarily due to:

- An increase of $16 million due to an electric distribution rate increase effective September 2014.
- An increase of $13 million due to higher sales primarily as a result of warmer weather during the second and third quarters of 2015, as compared to 2014.

The aggregate amount of these increases was partially offset by:

- A decrease of $3 million due to lower non-weather related average customer usage.
- A decrease of $2 million in transmission revenue due to the establishment of a reserve related to the FERC ROE challenges, partially offset by higher rates effective June 1, 2014 and June 1, 2015 related to increases in transmission plant investment and operating expenses.

Default Electricity Supply

	2015	2014	Change
Default Electricity Supply Revenue			
Residential	$375	$292	$ 83
Commercial and industrial	170	143	27
Other	87	152	(65)
Total Default Electricity Supply Revenue	$632	$587	$ 45

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.

	2015	2014	Change
Default Electricity Supply Sales (GWh)			
Residential	2,983	2,673	310
Commercial and industrial	1,029	798	231
Other	10	8	2
Total Default Electricity Supply Sales	4,022	3,479	543

	2015	2014	Change
Default Electricity Supply Customers (in thousands)			
Residential	424	408	16
Commercial and industrial	45	44	1
Other	—	—	—
Total Default Electricity Supply Customers	469	452	17

Default Electricity Supply Revenue increased by $45 million primarily due to:

- An increase of $51 million as a result of higher Default Electricity Supply rates.
- An increase of $46 million due to higher sales primarily as a result of customer migration from competitive suppliers.
- An increase of $25 million due to higher sales primarily as a result of colder weather during the first quarter and warmer weather during the second and third quarters of 2015, as compared to 2014.

The aggregate amount of these increases was partially offset by:

- A decrease of $66 million in wholesale energy and capacity resale revenues primarily due to lower market prices for the resale of electricity and capacity purchased from NUGs.
- A decrease of $11 million due to lower non-weather related average customer usage.

The variances described above with respect to Default Electricity Supply Revenue include the effects of a decrease of $5 million in ACE's BGS unbilled revenue resulting primarily from lower average customer usage in the unbilled revenue period for the nine months ended September 30, 2015 as compared to the corresponding period in 2014. Such a decrease in ACE's BGS unbilled revenue has the effect of directly decreasing the profitability of ACE's Default Electricity Supply business ($3 million decrease in net income) as these unbilled revenues are not included in the deferral calculation until they are billed to customers under the BGS terms approved by the NJBPU.

For the nine months ended September 30, 2015 and 2014, the percentages of ACE's total distribution sales that are derived from customers receiving Default Electricity Supply are 56% and 50%, respectively.

<u>Operating Expenses</u>

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 increased by $31 million to $535 million in 2015 from $504 million in 2014 primarily due to:

- An increase of $28 million primarily due to customer migration from competitive suppliers.
- An increase of $17 million due to higher electricity sales primarily as a result of warmer weather during the second and third quarters of 2015, as compared to 2014.

The aggregate amount of these increases was partially offset by a decrease of $14 million due to lower average electricity costs under BGS contracts.

Other Operation and Maintenance

Other Operation and Maintenance expense increased by $31 million to $209 million in 2015 from $178 million in 2014 primarily due to:

- An increase of $10 million due to implementation and support costs related to a new customer information system.
- An increase of $7 million in tree trimming and system maintenance costs.
- An increase of $4 million in bad debt expense that is deferred and recoverable.
- An increase of $4 million in storm restoration costs.
- An increase of $2 million in internal and external Merger-related integration costs.
- An increase of $2 million in customer service costs.

ACE's service territory was affected by a severe storm with damaging winds and heavy rains on June 23, 2015. The storm resulted in widespread customer outages and caused damage to the electric transmission and distribution systems.

Total incremental storm restoration costs incurred by ACE for the storm through September 30, 2015 were $35 million, with $13 million incurred for repair work and $22 million incurred as capital expenditures. Costs incurred for repair work of $13 million were deferred as regulatory assets to reflect the probable recovery of these costs in New Jersey. As of September 30, 2015, the total incremental storm restoration costs associated with the June 23, 2015 storm included $9 million of estimated costs for unbilled restoration services provided by certain outside contractors. Actual costs for these services may vary from the estimates. ACE intends to pursue recovery of these incremental storm restoration costs in its next electric distribution base rate case.

The increased costs referred to above for implementation and support of a new customer information system, system maintenance, storm restoration and customer service each involve internal labor costs which reflect a higher level of pension benefit cost in 2015, as compared to 2014.

Depreciation and Amortization

Depreciation and Amortization expense increased by $18 million to $135 million in 2015 from $117 million in 2014 primarily due to:

- An increase of $15 million in amortization of stranded costs primarily as the result of higher revenue due to a rate increase effective October 2014 for the ACE Market Transition Charge tax (partially offset in Default Electricity Supply Revenue).
- An increase of $3 million due to utility plant additions.

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 costs incurred by ACE related to the New Jersey Societal Benefit Program. The cost of electricity purchased is reported under Purchased Energy expense and the corresponding revenue is reported under Default Electricity Supply Revenue. The costs of the New Jersey Societal Benefit Program are 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 $4 million to an expense of $34 million in 2015 as compared to an expense of $30 million in 2014, primarily due to an increase in deferred electricity expense as a result of higher Default Electricity Supply revenue rates.

Income Tax Expense

ACE's consolidated income tax expense decreased by $8 million to $16 million in 2015 from $24 million in 2014. ACE's consolidated effective income tax rates for the nine months ended September 30, 2015 and 2014 were 36.4% and 38.1%, respectively.

Capital Requirements

Capital Expenditures

ACE's capital expenditures for the nine months ended September 30, 2015 were $212 million. These expenditures were primarily related to capital costs associated with distribution and transmission services. 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.

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 was offset against smart grid-related capital expenditures of ACE. The remaining $7 million is being used to offset incremental expenditures associated with direct load control and other programs, which have been deferred as regulatory assets. As of September 30, 2015, ACE has received all of its DOE award payments.

The IRS announced that, to the extent these grants are expended on capital items, they would 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, Executive Vice President (Power Delivery), Chief Financial Officer, General Counsel, Chief Information Officer and other senior executives. The CRMC monitors interest rate fluctuation, commodity price fluctuation, and 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 (20), "Discontinued Operations," of the consolidated financial statements of PHI included in its 2014 Form 10-K, Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" in PHI's 2014 Form 10-K, and Note (13), "Derivative Instruments and Hedging Activities," 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' 2014 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

Conclusion 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, 2015, 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, 2015, 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 (15), "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 (11), "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 2014 Form 10-K. There have been no material changes to any Reporting Company's risk factors as disclosed in the 2014 Form 10-K, except as set forth below:

Failure to obtain all required regulatory approvals of the Merger, including approval of the DCPSC, could have a material adverse effect on the business, operations, financial condition, results of operations and prospects of PHI and each of its utility subsidiaries, and on the market price of PHI's common stock.

In August 2015, the DCPSC issued an order denying the merger application as originally filed by PHI and Exelon. In response to this decision, PHI, Exelon, Pepco and certain of their respective affiliates have entered into the DC Settlement Agreement with the District of Columbia Government, the Office of the People's Counsel and other parties setting forth additional or modified undertakings, conditions and commitments. There can be no assurance, however, that the DCPSC will approve the Merger on the terms set forth in the DC Settlement Agreement or on any other terms.

Under the terms of the Merger Agreement, as amended, either Exelon or Pepco has the right to terminate the Merger Agreement if the DCPSC does not approve the Merger, fails to act on the Merger in accordance with the timetable set forth in the DC Settlement Agreement, approves the Merger subject to conditions that are inconsistent with the terms of the DC Settlement Agreement, or a closing condition has not been satisfied or waived on or before 151 days following the filing of the DC Settlement Agreement with the DCPSC. The termination of the Merger Agreement would likely have a material adverse effect on the business, operations, financial condition, results of operations and prospects of PHI and each of its utility subsidiaries and a negative impact on the trading price of PHI's common stock.

During the 18 months while the Merger has been pending, PHI's utility subsidiaries, in accordance with the terms of the Merger Agreement, have not filed any new distribution base rate cases, thereby foregoing rate increases that they might otherwise have sought. At the same time, each of the utility subsidiaries generally has maintained its pre-Merger Agreement level of infrastructure spending in its service territory. As a consequence, if the Merger is not completed, PHI and each of its utility subsidiaries expect that they will be required to undertake certain actions to address their ongoing results of operations and financial condition. These actions are likely to include, but may not be limited to, a decrease in capital and operational and maintenance expenditures, and a reevaluation of PHI's common stock dividend policy.

For a further discussion of these risks, see the risk factors located in Part I, Item 1A. "Risk Factors" in each Reporting Company's 2014 Form 10-K entitled (i) "PHI's utility subsidiaries are subject to comprehensive regulation which significantly affects their operations. PHI's utility subsidiaries may be subject to fines, penalties and other sanctions for the inability to meet these requirements," (ii) "PHI's profitability is largely dependent on its ability to recover costs of providing utility services to its customers and to earn an adequate return on its capital investments. The failure of PHI's utility subsidiaries to obtain timely recognition of costs in rates may have a negative effect on PHI's results of operations and financial condition," (iii) "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," and (iv) "Any reductions in or other actions with respect to the credit ratings of PHI or any of its subsidiaries could increase its financing costs and the cost of maintaining certain contractual relationships.

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
2.1	PHI Pepco DPL ACE	Agreement and Plan of Merger, dated as of April 29, 2014, among PHI, Exelon and Merger Sub.	Exhibit 2.1 to PHI's Form 8-K, April 30, 2014.
2.2	PHI	Subscription Agreement, dated as of April 29, 2014, between PHI and Exelon	Exhibit 2.2 to PHI's Form 8-K, April 30, 2014.
2.3	PHI	Extension letter dated July 29, 2015	Exhibit 2.1 to PHI's Form 8-K, July 29, 2015.
2.4	PHI	Letter agreement, dated as of October 6, 2015, among Pepco Holdings, Inc., Exelon Corporation and Purple Acquisition Corp.	Exhibit 2 to PHI's Form 8-K, October 6, 2015.
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	Certificate of Designation for Series A Non-Voting Non-Convertible Preferred Stock	Exhibit 3.1 to PHI's Form 8-K, April 30, 2014.
3.7	PHI	Bylaws	Exhibit 3 to PHI's Form 8-K, October 7, 2015.
3.8	Pepco	By-Laws	Exhibit 3.2 to Pepco's Form 10-Q, May 5, 2006.
3.9	DPL	Amended and Restated Bylaws	Exhibit 3.2.1 to DPL's Form 10-Q, May 9, 2005.
3.10	ACE	Amended and Restated Bylaws	Exhibit 3.2.2 to ACE's Form 10-Q, May 9, 2005.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
4.1	DPL	Form of First Mortgage Bond, 4.15% Series due May 15, 2045 (included in Exhibit 4.2)	—
4.2	DPL	Supplemental Indenture, dated as of May 4, 2015, with respect to the Mortgage and Deed of Trust, dated October 1, 1943	Exhibit 4.2 to DPL's Form 8-K, May 5, 2015.
4.3	PHI	Certificate of Series A Non-Voting Non-Convertible Preferred Stock	Exhibit 4.1 to PHI's Form 8-K, April 30, 2014.
10.1	DPL	Purchase Agreement, dated May 4, 2015, among DPL and J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, and Scotia Capital (USA) Inc., as representatives of the several underwriters named therein	Exhibit 1.1 to DPL's Form 8-K, May 5, 2015.
10.2.1	PHI	Pepco Holdings, Inc. 2012 Long-Term Incentive Plan	Exhibit 10.10 to PHI's Form 10-K, February 28, 2013.
10.2.2	PHI	Amendment to Pepco Holdings, Inc. 2012 Long-Term Incentive Plan, effective as of March 28, 2014	Exhibit 10.2.2 to PHI's Form 10-Q, May 7, 2014
10.2.3	PHI	Second Amendment to Pepco Holdings, Inc. 2012 Long-Term Incentive Plan, dated February 26, 2015	Exhibit 10.21.2 to PHI's Form 10-K, February 27, 2015.
10.3.1	PHI	Pepco Holdings, Inc. Amended and Restated Annual Executive Incentive Compensation Plan	Exhibit 10.30.1 to PHI's Form 10-K, February 24, 2012.
10.3.2	PHI	Amendment to Pepco Holdings, Inc. Amended and Restated Annual Executive Incentive Compensation Plan, dated February 26, 2015	Exhibit 10.19.1 to PHI's Form 10-K, February 27, 2015.
10.4	PHI	Form of 2015 Restricted Stock Unit Agreement (Time-Vested) Under the PHI 2012 Long-Term Incentive Plan	Exhibit 10.4 to PHI's Form 10-Q, May 1, 2015.
10.5	PHI	Form of 2015 Restricted Stock Unit Agreement (Time-Vested) Under the PHI 2012 Long-Term Incentive Plan for Joseph M. Rigby	Exhibit 10.5 to PHI's Form 10-Q, May 1, 2015.
10.6	PHI	Form of 2015 Restricted Stock Unit Agreement (Time-Vested) Under the PHI 2012 Long-Term Incentive Plan for Kevin C. Fitzgerald	Exhibit 10.6 to PHI's Form 10-Q, May 1, 2015.
10.7	PHI Pepco DPL ACE	Third Amendment to Second Amended and Restated Credit Agreement dated as of May 1, 2015, by and among PHI, Pepco, DPL, ACE, the various financial institutions from time to time party thereto, Bank of America, N.A. and Wells Fargo Bank, National Association.	Exhibit 10.1 to PHI's Form 8-K, May 1, 2015.
10.8	PHI	$300,000,000 Term Loan Agreement by and among Pepco Holdings, Inc., The Bank of Nova Scotia, as Administrative Agent, and the Lenders Party thereto, dated July 30, 2015	Exhibit 10 to PHI's Form 8-K, July 30, 2015.
10.9	PHI	Extension Agreement, dated as of September 11, 2015, by and between PHI and Kevin C. Fitzgerald	Exhibit 10 to PHI's Form 8-K, September 11, 2015.
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.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
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.
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)

October 23, 2015

By /s/ FREDERICK J. 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

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
2.1	PHI Pepco DPL ACE	Agreement and Plan of Merger, dated as of April 29, 2014, among PHI, Exelon and Merger Sub.	Exhibit 2.1 to PHI's Form 8-K, April 30, 2014.
2.2	PHI	Subscription Agreement, dated as of April 29, 2014, between PHI and Exelon	Exhibit 2.2 to PHI's Form 8-K, April 30, 2014.
2.3	PHI	Extension letter dated July 29, 2015	Exhibit 2.1 to PHI's Form 8-K, July 29, 2015.
2.4	PHI	Letter agreement, dated as of October 6, 2015, among Pepco Holdings, Inc., Exelon Corporation and Purple Acquisition Corp.	Exhibit 2 to PHI's Form 8-K, October 6, 2015.
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	Certificate of Designation for Series A Non-Voting Non-Convertible Preferred Stock	Exhibit 3.1 to PHI's Form 8-K, April 30, 2014.
3.7	PHI	Bylaws	Exhibit 3 to PHI's Form 8-K, October 7, 2015.
3.8	Pepco	By-Laws	Exhibit 3.2 to Pepco's Form 10-Q, May 5, 2006.
3.9	DPL	Amended and Restated Bylaws	Exhibit 3.2.1 to DPL's Form 10-Q, May 9, 2005.
3.10	ACE	Amended and Restated Bylaws	Exhibit 3.2.2 to ACE's Form 10-Q, May 9, 2005.
4.1	DPL	Form of First Mortgage Bond, 4.15% Series due May 15, 2045 (included in Exhibit 4.2)	—
4.2	DPL	Supplemental Indenture, dated as of May 4, 2015, with respect to the Mortgage and Deed of Trust, dated October 1, 1943	Exhibit 4.2 to DPL's Form 8-K, May 5, 2015.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
4.3	PHI	Certificate of Series A Non-Voting Non-Convertible Preferred Stock	Exhibit 4.1 to PHI's Form 8-K, April 30, 2014.
10.1	DPL	Purchase Agreement, May 4, 2015, among DPL and J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, and Scotia Capital (USA) Inc., as representatives of the several Underwriters named therein	Exhibit 1.1 to DPL's Form 8-K, May 5, 2015.
10.2.1	PHI	Pepco Holdings, Inc. 2012 Long-Term Incentive Plan	Exhibit 10.10 to PHI's Form 10-K, February 28, 2013.
10.2.2	PHI	Amendment to Pepco Holdings, Inc. 2012 Long-Term Incentive Plan, effective as of March 28, 2014	Exhibit 10.2.2 to PHI's Form 10-Q, May 7, 2014.
10.2.3	PHI	Second Amendment to Pepco Holdings, Inc. 2012 Long-Term Incentive Plan, dated February 26, 2015	Exhibit 10.21.2 to PHI's Form 10-K, February 27, 2015.
10.3.1	PHI	Pepco Holdings, Inc. Amended and Restated Annual Executive Incentive Compensation Plan	Exhibit 10.30.1 to PHI's Form 10-K, February 24, 2012.
10.3.2	PHI	Amendment to Pepco Holdings, Inc. Amended and Restated Annual Executive Incentive Compensation Plan, dated February 26, 2015	Exhibit 10.19.1 to PHI's Form 10-K, February 27, 2015.
10.4	PHI	Form of 2015 Restricted Stock Unit Agreement (Time-Vested) Under the PHI 2012 Long-Term Incentive Plan	Exhibit 10.4 to PHI's Form 10-Q, May 1, 2015.
10.5	PHI	Form of 2015 Restricted Stock Unit Agreement (Time-Vested) Under the PHI 2012 Long-Term Incentive Plan for Joseph M. Rigby	Exhibit 10.5 to PHI's Form 10-Q, May 1, 2015.
10.6	PHI	Form of 2015 Restricted Stock Unit Agreement (Time-Vested) Under the PHI 2012 Long-Term Incentive Plan for Kevin C. Fitzgerald	Exhibit 10.6 to PHI's Form 10-Q, May 1, 2015.
10.7	PHI Pepco DPL ACE	Third Amendment to Second Amended and Restated Credit Agreement, dated as of May 1, 2015, by and among PHI, Pepco, DPL, ACE, the various financial institutions from time to time party thereto, Bank of America, N.A. and Wells Fargo Bank, National Association.	Exhibit 10.1 to PHI's Form 8-K, May 1, 2015.
10.8	PHI	$300,000,000 Term Loan Agreement by and among Pepco Holdings, Inc., The Bank of Nova Scotia, as Administrative Agent, and the Lenders Party thereto, dated July 30, 2015	Exhibit 10 to PHI's Form 8-K, July 30, 2015.
10.9	PHI	Extension Agreement, dated as of September 11, 2015, by and between PHI and Kevin C. Fitzgerald	Exhibit 10 to PHI's Form 8-K, September 11, 2015.
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.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
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.
31.8	ACE	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
99.1	PHI	Statement Re: Computation of Ratios	Filed herewith.
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101.PRE	PHI Pepco DPL ACE	XBRL Taxonomy Extension Presentation Linkbase Document	Filed herewith.

INDEX TO EXHIBITS FURNISHED HEREWITH

Exhibit No.	Registrant(s)	Description of Exhibit
32.1	PHI	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350
32.2	Pepco	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350
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: October 23, 2015

/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: October 23, 2015

/s/ FREDERICK J. 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: October 23, 2015

/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: October 23, 2015

/s/ FREDERICK J. 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: October 23, 2015

/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: October 23, 2015

/s/ FREDERICK J. 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: October 23, 2015

/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: October 23, 2015

/s/ FREDERICK J. 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, 2015, 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.

October 23, 2015	/s/ JOSEPH M. RIGBY Joseph M. Rigby Chairman of the Board, President and Chief Executive Officer
October 23, 2015	/s/ FREDERICK J. 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, 2015, 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.

October 23, 2015	/s/ DAVID M. VELAZQUEZ David M. Velazquez President and Chief Executive Officer
October 23, 2015	/s/ FREDERICK J. 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, 2015, 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.

October 23, 2015	/s/ DAVID M. VELAZQUEZ David M. Velazquez President and Chief Executive Officer
October 23, 2015	/s/ FREDERICK J. 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, 2015, 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.

October 23, 2015	/s/ DAVID M. VELAZQUEZ David M. Velazquez President and Chief Executive Officer
October 23, 2015	/s/ FREDERICK J. 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, 2015	For the Year Ended December 31, 2014	2013	2012	2011	2010
		(millions of dollars)				
Earnings						
Net income from continuing operations	$ 197	$ 242	$ 110	$ 218	$ 222	$ 91
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	—	—	(2)	(1)	3	1
Minority interest loss	—	—	—	—	—	—
Income tax expense (benefit) related to continuing operations	106	138	319	103	114	(14)
Pre-tax income for common stock	303	380	427	320	339	78
Add: Fixed charges*	235	300	301	286	275	312
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 538	$ 680	$ 728	$ 606	$ 614	$ 390
***Fixed Charges**						
Interest on long-term debt	$ 206	$ 264	$ 265	$ 249	$ 239	$ 269
Interest capitalized	—	—	—	—	—	—
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	11	12	14	16	14	21
Interest component of rentals	18	24	22	21	22	22
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 235	$ 300	$ 301	$ 286	$ 275	$ 312
Ratio of earnings to fixed charges (a)	2.29	2.27	2.42	2.12	2.23	1.25

(a) Pepco Holdings, Inc. issued certain preferred equity securities during 2014 and 2015 that are excluded from equity since the securities contain conditions for redemption that are not solely within the control of PHI. The cumulative and unpaid dividends associated with the preferred equity securities, which were immaterial for the nine months ended September 30, 2015 and for the year ended December 31, 2014, are included in fixed charges as a component of interest on long-term debt. Accordingly, 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, 2015	For the Year Ended December 31, 2014	2013	2012	2011	2010
		(millions of dollars)				
Earnings						
Net income for common stock	$ 128	$ 171	$ 150	$ 126	$ 99	$ 108
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—	—
Minority interest loss	—	—	—	—	—	—
Income tax expense	62	92	79	48	36	37
Pre-tax income for common stock	190	263	229	174	135	145
Add: Fixed charges*	103	128	121	113	111	111
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 293	$ 391	$ 350	$ 287	$ 246	$ 256
***Fixed Charges**						
Interest on long-term debt	$ 94	$ 116	$ 109	$ 101	$ 97	$ 97
Interest capitalized	—	—	—	—	—	—
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	3	5	5	5	4	4
Interest component of rentals	6	7	7	7	10	10
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 103	$ 128	$ 121	$ 113	$ 111	$ 111
Ratio of earnings to fixed charges (a)	2.84	3.05	2.89	2.54	2.22	2.31

(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, 2015	For the Year Ended December 31, 2014	2013	2012	2011	2010
		(millions of dollars)				
Earnings						
Net income for common stock	$ 55	$ 104	$ 89	$ 73	$ 71	$ 45
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—	—
Minority interest loss	—	—	—	—	—	—
Income tax expense	35	65	56	44	42	31
Pre-tax income for common stock	90	169	145	117	113	76
Add: Fixed charges*	40	53	55	52	49	48
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 130	$ 222	$ 200	$ 169	$ 162	$ 124
***Fixed Charges**						
Interest on long-term debt	$ 36	$ 46	$ 49	$ 45	$ 42	$ 43
Interest capitalized	—	—	—	—	—	—
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	2	3	3	4	4	3
Interest component of rentals	2	4	3	3	3	2
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 40	$ 53	$ 55	$ 52	$ 49	$ 48
Ratio of earnings to fixed charges (a)	3.25	4.19	3.64	3.25	3.31	2.58

(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, 2015	For the Year Ended December 31, 2014	2013	2012	2011	2010
		(millions of dollars)				
Earnings						
Net income for common stock	$ 28	$ 45	$ 50	$ 35	$ 39	$ 53
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—	—
Minority interest loss	—	—	—	—	—	—
Income tax expense	16	28	19	18	33	43
Pre-tax income for common stock	44	73	69	53	72	96
Add: Fixed charges*	52	68	72	75	74	69
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 96	$ 141	$ 141	$ 128	$ 146	$ 165
***Fixed Charges**						
Interest on long-term debt	$ 47	$ 61	$ 65	$ 69	$ 69	$ 63
Interest capitalized	—	—	—	—	—	—
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	2	3	3	2	2	3
Interest component of rentals	3	4	4	4	3	3
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 52	$ 68	$ 72	$ 75	$ 74	$ 69
Ratio of earnings to fixed charges (a)	1.85	2.07	1.96	1.71	1.97	2.39

(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.