PROCTER & GAMBLE Co
Form 4
March 02, 2016

FORM 4

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL
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(Print or Type Responses)

1. Name and Address of Reporting Person *
Biegger Mark F
(Last) (First) (Middle)
ONE PROCTER & GAMBLE PLAZA
(Street)
CINCINNATI, OH
(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
PROCTER & GAMBLE Co [PG]

3. Date of Earliest Transaction (Month/Day/Year)
02/29/2016

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer
(Check all applicable)
_____ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
Chief Human Resources Officer

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock								16,389.11 (1)	D	
Common Stock								7	I	By son Noah
Common Stock								16,112.8645 (2)	I	By Retirement Plan Trustees

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

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Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned (*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)	
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares
Restricted Stock Units	(3)	02/16/2016		A	V	20.526		(4)	(4)	Common Stock	20.526
Stock Option (Right to Buy)	$ 80.29 (5)	02/29/2016		A		88,430		02/28/2019	02/27/2026	Common Stock	88,430

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Biegger Mark F ONE PROCTER & GAMBLE PLAZA CINCINNATI, OH			Chief Human Resources Officer	

Signatures

/s/ Sandra T. Lane, Attorney-In-Fact for MARK F. BIEGGER	03/02/2016
**Signature of Reporting Person	Date

Explanation of Responses:

*	If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).
**	Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).
(1)	Total includes grant of dividend equivalents on February 16, 2016 in the form of Restricted Stock Units (RSU's) settled in common stock.
(2)	Reflects adjustment to PST through December 31, 2015.
(3)	Dividend equivalents in the form of Retirement Restricted Stock Units (RSUs) previously awarded pursuant to Issuer's retirement program. All such RSUs represent a contingent right to receive Procter & Gamble common stock or cash settlement.
(4)	

These units will deliver in shares or cash settlement on retirement from the company, unless delivery is deferred or such shares are contributed to reporting person's deferred compensation account.

(5) Employee stock option granted pursuant to Issuer's 2014 Stock and Incentive Compensation Plan.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
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Public authorities & electric railroads

205	214	(4.2)%	(4.2)%	432	443	(2.5)%	(2.5)%

Total retail deliveries

8,771	8,944	(1.9)%	0.3%	18,032	19,036	(5.3)%	0.3%

Number of Electric Customers	As of June 30, 2016	2015
Residential	1,449,450	1,437,523
Small commercial & industrial	149,523	148,918
Large commercial & industrial	3,088	3,095
Public authorities & electric railroads	9,813	9,803
Total	1,611,874	1,599,339

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Electric Revenue	Three Months Ended June 30, 2016	2015	% Change	Six Months Ended June 30, 2016	2015	% Change
Retail Sales[a]						
Residential	$ 355	$ 365	(2.7)%	$ 766	$ 815	(6.0)%
Small commercial & industrial	106	102	3.9%	225	217	3.7%
Large commercial & industrial	65	54	20.4%	123	108	13.9%
Public authorities & electric railroads	9	8	12.5%	17	15	13.3%
Total retail	535	529	1.1%	1,131	1,155	(2.1)%
Other revenue[b]	52	53	(1.9)%	101	104	(2.9)%
Total electric revenue[c]	$ 587	$ 582	0.9%	$ 1,232	$ 1,259	(2.1)%

(a) Reflects delivery volumes and revenue from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.
(b) Other revenue primarily includes transmission revenue from PJM and wholesale electric revenue, in addition to rental income.
(c) Includes operating revenues from affiliates totaling $2 million and less than $1 million for the three months ended June 30, 2016 and 2015, respectively, and $4 million and less than $1 million for the six months ended June 30, 2016 and 2015, respectively.

PECO Natural Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2016	2015	% Change	Weather - Normal % Change	Six Months Ended June 30, 2016	2015	% Change	Weather - Normal % Change
Retail Delivery								
Retail sales[a]	7,883	7,233	9.0%	(6.7)%	34,994	42,095	(16.9)%	2.2%
Transportation and other	5,906	5,431	8.7%	6.0%	13,602	14,128	(3.7)%	3.3%
Total natural gas deliveries	13,789	12,664	8.9%	(1.5)%	48,596	56,223	(13.6)%	2.5%

Number of Natural Gas Customers	As of June 30, 2016	2015
Residential	469,230	464,333
Commercial & industrial	43,046	42,603
Total retail	512,276	506,936
Transportation	811	845
Total	513,087	507,781

Natural Gas Revenue	Three Months Ended June 30, 2016	2015	% Change	Six Months Ended June 30, 2016	2015	% Change
Retail Sales						
Retail sales[a]	$ 70	$ 72	(2.8)%	$ 256	$ 368	(30.4)%

Transportation and other	7	7	%	17	19	(10.5)%
Total natural gas revenues[b]	$ 77	$ 79	(2.5)%	$ 273	$ 387	(29.5)%

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

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(b) Includes operating revenues from affiliates totaling less than $1 million for both the three months ended June 30, 2016 and 2015, and the six months ended June 30, 2016, and $1 million for the six months ended June 30, 2015.

Results of Operations BGE

	Three Months Ended June 30,		Favorable (Unfavorable)	Six Months Ended June 30,		Favorable (Unfavorable)
	2016	2015	Variance	2016	2015	Variance
Operating revenues	$ 680	$ 628	$ 52	$ 1,609	$ 1,664	$ (55)
Purchased power and fuel	261	239	(22)	634	726	92
Revenue net of purchased power and fuel[(a)]	419	389	30	975	938	37
Other operating expenses						
Operating and maintenance	208	149	(59)	410	331	(79)
Depreciation and amortization	97	87	(10)	206	192	(14)
Taxes other than income	55	54	(1)	114	111	(3)
Total other operating expenses	360	290	(70)	730	634	(96)
Operating income	59	99	(40)	245	304	(59)
Other income and (deductions)						
Interest expense, net	(24)	(24)		(48)	(50)	2
Other, net	5	4	1	11	8	3
Total other income and (deductions)	(19)	(20)	1	(37)	(42)	5
Income before income taxes	40	79	(39)	208	262	(54)
Income taxes	6	32	26	73	105	32
Net income	34	47	(13)	135	157	(22)
Preference stock dividends	3	3		6	6	
Net income attributable to common shareholder	$ 31	$ 44	$ (13)	$ 129	$ 151	$ (22)

(a) BGE evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of purchased fuel expense for gas sales. BGE believes revenue net of purchased power and revenue net of purchased fuel are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015. BGE s net income attributable to common shareholder for the three months ended June 30, 2016 was lower than the same period in 2015, primarily due to an increase in Operating and maintenance expense as a result of reducing certain regulatory assets and other long-lived assets stemming from certain cost disallowances contained within the final smart grid rate order issued by the MDPSC in June 2016. The increase in Operating and maintenance expense was partially offset by an increase in Revenue net of purchased power and fuel, primarily as a result of an increase in transmission formula rate revenues, higher electric and natural gas revenues as a result of the distribution rate orders issued by the MDPSC in June 2016, and lower income tax expense driven by lower taxable income.

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Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015. BGE s net income attributable to common shareholder for the six months ended June 30, 2016 was lower than the same period in 2015, primarily due to an increase in Operating and maintenance expense as a result of reducing certain regulatory assets and other long-lived assets stemming from certain cost disallowances contained within the final smart grid rate order issued by the MDPSC in June 2016 and increased storm costs. The increase in Operating and maintenance expense was partially offset by an increase in Revenue net of purchased power and fuel, primarily as a result of an increase in transmission formula rate revenues, higher electric and natural gas revenues as a result of the distribution rate orders issued by the MDPSC in June 2016, and lower income tax expense driven by lower taxable income.

Operating Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to Operating revenue that are offset by their impact on Purchased power and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric generation or natural gas supplier. Operating revenue and Purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE s electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC s market-based SOS and gas commodity programs, respectively.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in the number of customers electing to use a competitive electric generation or natural gas supplier. All BGE customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customers choice of suppliers does not impact the volume of deliveries, but does affect revenue collected from customers related to supplied energy and natural gas service.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and six months ended June 30, 2016 and 2015, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Electric	62%	64%	59%	59%
Natural Gas	67%	67%	55%	50%

The number of retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at June 30, 2016 and 2015 consisted of the following:

	June 30, 2016		June 30, 2015	
	Number of Customers	% of total retail customers	Number of customers	% of total retail customers
Electric	337,400	27%	349,400	28%
Natural Gas	151,600	23%	157,300	24%

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The changes in BGE s operating revenues net of purchased power and fuel expense for the three and six months ended June 30, 2016, compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)			Six Months Ended June 30, Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution rate increase	$ 6	$ 1	$ 7	$ 6	$ 1	$ 7
Regulatory required programs	2	1	3			
Transmission revenue	8		8	20		20
Other	11	1	12	15	(5)	10
Total increase (decrease)	$ 27	$ 3	$ 30	$ 41	$ (4)	$ 37

Distribution Rate Increase. The increase in distribution rates for the three and six months ended June 30, 2016, compared to the same periods in 2015, was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective in June 2016 in accordance with the MDPSC approved electric and natural gas distribution rate case orders. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Revenue Decoupling. The demand for electricity and natural gas is affected by weather and usage conditions. The MDPSC allows BGE to record a monthly adjustment to its electric and natural gas distribution revenue from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service natural gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE s electric and natural gas distribution volumes, thereby recovering a specified dollar amount of distribution revenue per customer, by customer class, regardless of changes in actual consumption levels. This allows BGE to recognize revenue at MDPSC-approved levels per customer, regardless of what BGE s actual distribution volumes were for a billing period. Therefore, while this revenue is affected by customer growth (i.e., increase in the number of customers), it will not be affected by actual weather or usage conditions (i.e., changes in consumption per customer). BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE s service territory. The changes in heating degree days in BGE s service territory for the three and six months ended June 30, 2016 compared to the same periods in 2015 consisted of the following:

Heating and Cooling Degree-Days	2016	2015	Normal	% Change 2016 vs. 2015	% Change 2016 vs. Normal
Three Months Ended June 30,					
Heating Degree-Days	574	422	509	36.0%	12.8%
Cooling Degree-Days	219	317	257	(30.9)%	(14.8)%
Six Months Ended June 30,					
Heating Degree-Days	2,854	3,372	2,920	(15.4)%	(2.3)%
Cooling Degree-Days	219	317	257	(30.9)%	(14.8)%

Regulatory Required Programs. This represents the change in revenue collected under approved riders to recover costs incurred for the energy efficiency and demand response programs. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in BGE s Consolidated Statements of Operations and Comprehensive Income.

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Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants. During the three and six months ended June 30, 2016 compared to the same periods in 2015, the increase in transmission revenue was primarily due to increases in capital investment and operating and maintenance expense recoveries. See Operating and Maintenance Expense below and Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other. Other revenue, which can vary from period to period, includes miscellaneous revenue such as service application and late payment fees.

Operating and Maintenance Expense

The changes in operating and maintenance expense for the three and six months ended June 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Impairment on long-lived assets and losses on regulatory assets[(a)]	$ 52	$ 52
Storm-related costs	1	18
Uncollectible accounts expense[(b)]	5	(7)
City of Baltimore conduit fees[(c)]	8	15
BSC allocations[(d)]	1	7
Other	(8)	(6)
Total increase	$ 59	$ 79

(a) See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Uncollectible accounts increased primarily due to the impact of favorable second quarter weather conditions for the three months ended June 30, 2016 compared to the same period in 2015. Uncollectible accounts decreased primarily due to milder weather and improved customer behavior for the six months ended June 30, 2016 compared to the same periods in 2015.
(c) City of Baltimore conduit fees increased for the three and six months ended June 30, 2016 compared to the same periods in 2015 as a result of increased rental fees assessed by the City of Baltimore. See Executive Overview Environmental Legislative and Regulatory Developments above and Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.
(d) Primarily reflects increased information technology support services from BSC during 2016.

Depreciation and Amortization

The changes in depreciation and amortization expense for the three and six months ended June 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Depreciation expense[(a)]	$ 2	$ 7
Regulatory asset amortization[(b)]	8	7
Total increase	$ 10	$ 14

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization increased for the three and six months ended June 30, 2016 compared to the same periods in 2015 primarily due to an increase in regulatory asset amortization related to energy efficiency programs and recovery

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of the AMI programs under the final electric and natural gas distribution rate case order issued by the MDPSC in June 2016. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Taxes Other Than Income

Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income for the three and six months ended June 30, 2016 compared to the same periods in 2015 remained relatively consistent.

Interest Expense, Net

Interest expense, net remained relatively consistent during the three and six months ended June 30, 2016, compared to the same periods in 2015.

Effective Income Tax Rate

BGE s effective income tax rate was 15.0% and 40.5% for the three months ended June 30, 2016 and 2015, respectively. BGE s effective income tax rate was 35.1% and 40.1% for the six months ended June 30, 2016 and 2015, respectively. The decrease in the effective income tax rate for the three and six months ended June 30, 2016 compared to the same periods in 2015, is primarily due a lower taxable income and a cumulative adjustment to tax expense pending anticipated recovery from transmission customers. See Note 11 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2016	2015	% Change	Weather - Normal % Change	Six Months Ended June 30, 2016	2015	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	2,616	2,635	(0.7)%	n.m.	6,095	6,808	(10.5)%	n.m.
Small commercial & industrial	692	780	(11.3)%	n.m.	1,466	1,625	(9.8)%	n.m.
Large commercial & industrial	3,417	3,467	(1.4)%	n.m.	6,635	6,906	(3.9)%	n.m.
Public authorities & electric railroads	72	74	(2.7)%	n.m.	143	149	(4.0)%	n.m.
Total electric deliveries	6,797	6,956	(2.3)%	n.m.	14,339	15,488	(7.4)%	n.m.

Number of Electric Customers	As of June 30, 2016	2015
Residential	1,142,073	1,132,325
Small commercial & industrial	112,980	112,951
Large commercial & industrial	11,980	11,820
Public authorities & electric railroads	281	286
Total	1,267,314	1,257,382

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Electric Revenue	Three Months Ended June 30, 2016	2015	% Change	Six Months Ended June 30, 2016	2015	% Change
Retail Sales[(a)]						
Residential	$ 324	$ 303	6.9%	$ 753	$ 752	0.1%
Small commercial & industrial	65	61	6.6%	137	137	%
Large commercial & industrial	115	109	5.5%	215	229	(6.1)%
Public authorities & electric railroads	9	8	12.5%	18	16	12.5%
Total retail	513	481	6.7%	1,123	1,134	(1.0)%
Other revenue[(b)]	71	60	18.3%	141	120	17.5%
Total electric revenue	$ 584	$ 541	7.9%	$ 1,264	$ 1,254	0.8%

(a) Reflects delivery volumes and revenue from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.
(b) Includes operating revenues from affiliates totaling $2 million and $4 million for the three and six months ended June 30, 2016.

BGE Natural Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2016	2015	% Change	Weather - Normal % Change	Six Months Ended June 30, 2016	2015	% Change	Weather - Normal % Change
Retail Deliveries[(a)]								
Retail sales	17,672	13,885	27.3%	n.m.	56,256	60,762	(7.4)%	n.m.
Transportation and other[(b)]	271	585	(53.7)%	n.m.	2,767	3,909	(29.2)%	n.m.
Total natural gas deliveries	17,943	14,470	24.0%	n.m.	59,023	64,671	(8.7)%	n.m.

Number of Gas Customers	As of June 30, 2016	2015
Residential	618,268	614,168
Commercial & industrial	44,078	44,004
Total	662,346	658,172

Natural Gas Revenue	Three Months Ended June 30, 2016	2015	% Change	Six Months Ended June 30, 2016	2015	% Change
Retail Sales[(a)]						
Retail sales	$ 93	$ 85	9.4%	$ 331	$ 384	(13.8)%
Transportation and other[(b)]	3	2	50.0%	14	26	(46.2)%
Total natural gas revenues[(c)]	$ 96	$ 87	10.3%	$ 345	$ 410	(15.9)%

(a) Reflects delivery volumes and revenue from customers purchasing natural gas directly from BGE and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. The cost of natural gas is charged to customers purchasing natural gas from BGE.

(b) Transportation and other gas revenue includes off-system revenue of 271 mmcfs ($2 million) and 585 mmcfs ($3 million) for the three months ended June 30, 2016 and 2015, respectively. Transportation and other gas revenue includes off-system revenue of 2,767 mmcfs ($11 million) and 3,909 mmcfs ($25 million) for the six months ended June 30, 2016 and 2015, respectively.

(c) Includes operating revenues from affiliates totaling $2 million and $1 million for the three months ended June 30, 2016 and 2015, respectively, and $5 million and $8 million for the six months ended June 30, 2016 and 2015, respectively.

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Results of Operations PHI

PHI s results of operations include the results of its three reportable segments, Pepco, DPL and ACE for all periods presented below. For Predecessor reporting periods, PHI s results of operations also include the results of PES and PCI. See Note 20 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding PHI s reportable segments. All material intercompany accounts and transactions have been eliminated in consolidation. A separate specific discussion of the results of operations for Pepco, DPL and ACE is presented elsewhere in this report.

As a result of the PHI Merger, the following consolidated financial results present two separate reporting periods for 2016. The Predecessor reporting periods represent PHI s results of operations for the three and six months ended June 30, 2015 and the period of January 1, 2016 to March 23, 2016. The Successor reporting periods represent PHI s results of operations for the three months ended June 30, 2016 and for the period from March 24, 2016 to June 30, 2016. All amounts presented below are before the impact of income taxes, except as noted.

	Successor	*Predecessor*	*Successor*	*Predecessor*	
	Three Months Ended June 30, 2016	**Three Months Ended June 30, 2015**	**March 24, 2016 to June 30, 2016**	**January 1, 2016 to March 23, 2016**	**Six Months Ended June 30, 2015**
Operating revenues	$ 1,066	$ 1,119	$ 1,171	$ 1,153	$ 2,473
Purchased power and fuel	416	429	454	497	1,067
Revenue net of purchased power and fuel[(a)]	650	690	717	656	1,406
Other operating expenses					
Operating and maintenance	246	288	695	294	589
Depreciation and amortization	160	152	174	152	307
Taxes other than income	108	111	123	105	229
Total other operating expenses	514	551	992	551	1,125
Operating income (loss)	136	139	(275)	105	281
Other income and (deductions)					
Interest expense, net	(66)	(71)	(71)	(65)	(140)
Other, net	11	12	12	(4)	21
Total other income and (deductions)	(55)	(59)	(59)	(69)	(119)
Income (loss) before income taxes	81	80	(334)	36	162
Income taxes	29	27	(77)	17	56
Net income (loss) attributable to membership interest/common shareholders	$ 52	$ 53	$ (257)	$ 19	$ 106

(a) PHI evaluates its operating performance using the measure of revenue net of purchased power and fuel expense for electric and natural gas sales. PHI believes revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. PHI has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Successor Period Three Months Ended June 30, 2016 Compared to the Predecessor Period Three Months Ended June 30, 2015

Net Income Attributable to Common Shareholders

PHI s net income attributable to common shareholders was $52 million for the three months ended June 30, 2016 as compared to $53 million for the three months ended June 30, 2015.

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Operating Revenue Net of Purchased Power and Fuel Expense

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed above, decreased by $40 million for the three months ended June 30, 2016 as compared to the three months ended June 30, 2015. The decrease is attributable to the following factors:

Increase of $15 million at Pepco primarily related to electric distribution revenue increases totaling $9 million due to customer growth, $3 million due to an EmPower Maryland rate increase effective February 2015, and $2 million higher transmission revenue due to a higher rate effective June 1, 2015, partially offset by lower revenue related to the MAPP abandonment recovery period ending March 2016.

Increase of $13 million at DPL primarily related to electric distribution revenue increases totaling $4 million due to customer growth, an increase of $2 million due to an EmPower Maryland rate increase effective February 2015, and $4 million higher transmission revenue due to a higher rate effective June 1, 2015, partially offset by lower revenue related to the MAPP abandonment recovery period ending March 2016.

Decrease of $9 million at ACE primarily related to lower average customer usage and lower weather-related sales.

Decrease of $63 million at PES due to PHI s results of operations including the results of PES in 2015 and not in 2016.

Operating and Maintenance Expense

Operating and maintenance expense decreased by $42 million for the three months ended June 30, 2016 as compared to the three months ended June 30, 2015. The decrease is attributable to the following factors:

Increase of $8 million at Pepco, DPL and ACE primarily due to $11 million of higher BSC and PHISCO allocations, $8 million resulting from a remeasurement of AMI-related regulatory assets, $4 million due to the write-off of construction work in progress, partially offset by a $12 million deferral of merger-related costs to a regulatory asset and $3 million lower labor, contracting and material costs primarily related to the implementation of a new customer information system in 2015.

Increase of $11 million at Corporate due primarily to inter-company and purchase accounting transactions.

Decrease of $61 million at PES due to PHI s results of operations including the results of PES in 2015 and not in 2016.

Depreciation and Amortization Expense

Depreciation and amortization expense increased by $8 million primarily due to higher depreciation of $6 million due to ongoing capital expenditures at Pepco, DPL, and ACE.

Taxes Other Than Income

Taxes other than income decreased by $3 million primarily due to lower utility taxes that are collected and passed through by Pepco and DPL.

Interest Expense, Net

Interest expense decreased by $5 million due to lower corporate interest expense.

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Other, Net

Other, net for the three months ended June 30, 2016 remained relatively level compared to the same period in 2015.

Effective Income Tax Rate

PHI s effective income tax rates for the three months ended June 30, 2016 and 2015 were 35.8% and 33.8%, respectively. See Note 11 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Successor Period March 24, 2016 to June 30, 2016

PHI s net loss attributable to common shareholders for the Successor period of March 24, 2016 to June 30, 2016 was $(257) million. There were no significant changes in the underlying trends affecting PHI s operations during the Successor period of March 24, 2016 to June 30, 2016 except for the pre-tax recording of $419 million of non-recurring merger-related costs within Operating and maintenance expense.

PHI s effective income tax rate for the Successor period of March 24, 2016 to June 30, 2016 was 23.1%. See Note 11 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Predecessor Period January 1, 2016 to March 23, 2016

PHI s net income attributable to common shareholders for the Predecessor period of January 1, 2016 to March 23, 2016 was $19 million. There were no significant changes in the underlying trends affecting PHI s operations during the Predecessor period of January 1, 2016 to March 23, 2016 except for the pre-tax recording of $29 million of non-recurring merger-related costs within Operating and maintenance expense and $18 million of preferred stock derivative expense within Other, net.

PHI s effective income tax rate for the Predecessor period of January 1, 2016 to March 23, 2016 was 47.2%. See Note 11 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Predecessor Period January 1, 2015 to June 30, 2015

PHI s net income attributable to common shareholders for the Predecessor period of the six months ended June 30, 2015 was $106 million. There were no significant changes in the underlying trends affecting PHI s operations during the Predecessor period of the six months ended June 30, 2015 except for the pre-tax recording of $30 million of implementation and support costs due to the completion of a new customer information system and $14 million of non-recurring merger-related costs within Operating and maintenance expense.

PHI s effective income tax rate for the six months ended June 30, 2015 was 34.6%. See Note 11 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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Results of Operations Pepco

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015	Favorable (Unfavorable) Variance
Operating revenues	$ 509	$ 504	$ 5	$ 1,061	$ 1,049	$ 12
Purchased power expense	152	162	10	351	373	22
Revenue net of purchased power expense[(a)]	357	342	15	710	676	34
Other operating expenses						
Operating and maintenance	109	103	(6)	399	215	(184)
Depreciation and amortization	70	63	(7)	144	125	(19)
Taxes other than income	89	93	4	182	190	8
Total other operating expenses	268	259	(9)	725	530	(195)
Gain on sale of assets	8		8	8		8
Operating income (loss)	97	83	14	(7)	146	(153)
Other income and (deductions)						
Interest expense, net	(31)	(31)		(68)	(61)	(7)
Other, net	6	8	(2)	14	13	1
Total other income and (deductions)	(25)	(23)	(2)	(54)	(48)	(6)
Income (loss) before income taxes	72	60	12	(61)	98	(159)
Income taxes	23	18	(5)	(1)	30	31
Net income (loss) attributable to common shareholder	$ 49	$ 42	$ 7	$ (60)	$ 68	$ (128)

(a) Pepco evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. Pepco believes revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Pepco has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income (Loss) Attributable to Common Shareholder

Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015. Pepco s net income attributable to common shareholder for the three months ended June 30, 2016, was higher than the same period in 2015, primarily due to an increase in revenue net of purchased power expense resulting from customer growth.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015. Pepco s net loss attributable to common shareholder for the six months ended June 30, 2016, compared unfavorably to Pepco s net income for the same period in 2015, primarily due to an increase in operating and maintenance expense due to merger-related costs.

Operating Revenue Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to Pepco s customers within its service territories at regulated rates. Operating revenues also include 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.

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Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All Pepco customers have the choice to purchase electricity from competitive electric generation suppliers. The customers choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and six months ended June 30, 2016, compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Electric	67%	66%	65%	63%

Retail customers purchasing electric generation from competitive electric generation suppliers at June 30, 2016 and 2015 consisted of the following:

	June 30, 2016		June 30, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	175,657	21%	158,753	20%

Retail deliveries purchased from competitive electric generation suppliers represented 73% and 73% of Pepco s retail kWh sales to the District of Columbia customers and 61% and 59% of Pepco s retail kWh sales to Maryland customers for the three and six months ended June 30, 2016 and 73% and 70% of Pepco s retail kWh sales to the District of Columbia customers and 61% and 58% of Pepco s retail kWh sales to Maryland customers for the three and six months ended June 30, 2015.

The costs related to default electricity supply are included in Purchased power expense. Operating revenues also include transmission enhancement credits that Pepco receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

Operating revenues also include 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.

Purchased power expense 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.

The changes in Pepco s operating revenues net of purchased power expense for the three and six months ended June 30, 2016 compared to the same period in 2015 consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Volume	$ 9	$ 14
Regulatory required programs	3	16
Transmission revenue	2	4
Other	1	
Total increase	$ 15	$ 34

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Revenue Decoupling. 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, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (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 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 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 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 the 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.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in Pepco s service territory. The changes in heating and cooling degree days in Pepco s service territory for the three and six months ended June 30, 2016 compared to the same periods in 2015 and normal weather consisted of the following:

				% Change	
	2016	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Three Months Ended June 30,					
Heating Degree-Days	397	200	324	98.5%	22.5%
Cooling Degree-Days	452	676	475	(33.1)%	(4.8)%
Six Months Ended June 30,					
Heating Degree-Days	2,407	2,691	2,494	(10.6)%	(3.5)%
Cooling Degree-Days	454	676	478	(32.8)%	(5.0)%

Volume. The increase in operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three and six months ended June 30, 2016 compared to the same periods in 2015, primarily reflects the impact of economic and customer growth.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and other taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing adjustments. The increase in revenue net of purchased power expense for the three and six months ended June 30, 2016 compared to the same periods in 2015 is a result of higher rates effective June 1, 2015 related to increases in transmission plant investment and operating expenses, partially offset by lower revenue related to the MAPP abandonment recovery period ending March 2016.

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Operating and Maintenance Expense

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Increase (Decrease)	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015	Increase (Decrease)
Operating and maintenance expense baseline	$ 107	$ 101	$ 6	$ 394	$ 210	$ 184
Operating and maintenance expense regulatory required programs[(a)]	2	2		5	5	
Total operating and maintenance expense	$ 109	$ 103	$ 6	$ 399	$ 215	$ 184

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

The changes in operating and maintenance expense for the three and six months ended June 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ (3)	$ 4
Storm-related costs	1	3
Remeasurement of AMI-related regulatory asset	7	7
Deferral of merger-related costs to regulatory asset	(9)	(9)
BSC and PHISCO allocations[(a)]	5	34
Merger commitments[(b)]		139
Other	5	6
Total increase	$ 6	$ 184

(a) Primarily related to merger severance and compensation costs.

(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for the three and six months ended June 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Depreciation expense[(a)]	$ 2	$ 4
Regulatory asset amortization[(b)]	5	16

Other				(1)
Total increase	$	7	$	19

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization increased for the three and six months ended June 30, 2016 compared to the same periods in 2015 primarily due to an EmPower Maryland surcharge rate increase effective February 2015, partially offset by lower amortization of MAPP abandonment costs.

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Taxes Other Than Income

Taxes other than income for the three and six months ended June 30, 2016 compared to the same periods in 2015 decreased primarily due to lower property taxes in Maryland and lower utility taxes that are collected and passed through by Pepco.

Gain on Sale of Assets

Gain on sale of assets for the three and six months ended June 30, 2016 compared to the same periods in 2015 increased due to a second quarter 2016 gain recorded from the sale of land.

Interest Expense, Net

Interest expense, net for the six months ended June 30, 2016 compared to the same period in 2015 increased $7 million primarily due to the recording of interest expense for an uncertain tax position in the first quarter of 2016.

Other, Net

Other, net for the three months ended June 30, 2016 compared to the same period in 2015 decreased primarily due to lower income from the return on AMI-related regulatory assets.

Other, net for the six months ended June 30, 2016 compared to the same period in 2015 increased primarily due to higher income from AFUDC.

Effective Income Tax Rate

Pepco s effective income tax rate was 31.9% and 30.0% for three months ended June 30, 2016 and 2015, respectively. Pepco s effective income tax rate was 1.6% and 30.6% for the six months ended June 30, 2016 and 2015, respectively. See Note 11 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates. As a result of the merger, Pepco recorded an after-tax charge of $33 million during the six months ended June 30, 2016 as a result of assessment and remeasurement of certain federal and state uncertain tax positions.

Pepco Electric Operating Statistics and Revenue Detail

	Three Months Ended June 30,				Six Months Ended June 30,			
Retail Deliveries to Customers (in GWhs)	**2016**	**2015**	**% Change**	**Weather - Normal % Change**	**2016**	**2015**	**% Change**	**Weather - Normal % Change**
Retail Deliveries[(a)]								
Residential	1,760	1,899	(7.3)%	0.8%	3,978	4,489	(11.4)%	(1.6)%
Small commercial & industrial	348	307	13.4%	0.3%	730	771	(5.3)%	(0.5)%
Large commercial & industrial	3,631	3,897	(6.8)%	(0.1)%	7,576	7,505	0.9%	(0.4)%
Public authorities & electric railroads	176	179	(1.7)%	%	364	363	0.3%	(0.4)%
Total retail deliveries	5,915	6,282	(5.8)%	1.0%	12,648	13,128	(3.7)%	(0.8)%

	As of June 30,	
Number of Electric Customers	**2016**	**2015**
Residential	771,541	739,440
Small commercial & industrial	53,345	53,413
Large commercial & industrial	21,401	20,515
Public authorities & electric railroads	127	121

Total	846,414	813,489

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Electric Revenue	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	% Change	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015	% Change
Retail Sales[(a)]						
Residential	$ 220	$ 220	%	$ 476	$ 486	(2.1)%
Small commercial & industrial	36	36	%	73	73	%
Large commercial & industrial	195	193	1.0%	395	379	4.2%
Public authorities & electric railroads	8	8	%	16	16	%
Total retail	459	457	0.4%	960	954	0.6%
Other revenue[(b)]	50	47	6.4%	101	95	6.3%
Total electric revenue[(c)]	$ 509	$ 504	1.0%	$ 1,061	$ 1,049	1.1%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from Pepco and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from Pepco, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.
(c) Includes operating revenues from affiliates totaling $1 million and $1 million for the three months ended June 30, 2016 and 2015, respectively, and $3 million and $2 million for the six months ended June 30, 2016 and 2015, respectively.

Results of Operations DPL

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015	Favorable (Unfavorable) Variance
Operating revenues	$ 281	$ 271	$ 10	$ 643	$ 691	$ (48)
Purchased power and fuel	122	125	3	298	350	52
Revenue net of purchased power and fuel[(a)]	159	146	13	345	341	4
Other operating expenses						
Operating and maintenance	78	75	(3)	283	157	(126)
Depreciation, amortization and accretion	38	35	(3)	76	74	(2)
Taxes other than income	13	12	(1)	28	24	(4)
Total other operating expenses	129	122	(7)	387	255	(132)
Operating income (loss)	30	24	6	(42)	86	(128)
Other income and (deductions)						
Interest expense, net	(13)	(13)		(25)	(25)	
Other, net	3	2	1	6	5	1
Total other income and (deductions)	(10)	(11)	1	(19)	(20)	1
Income (loss) before income taxes	20	13	7	(61)	66	(127)
Income taxes	8	5	(3)	(1)	26	27
Net income (loss) attributable to common shareholder	$ 12	$ 8	$ 4	$ (60)	$ 40	$ (100)

(a) DPL evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of fuel expense for natural gas sales. DPL believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements because they provide information that can be used to evaluate its operational performance. DPL has included the analysis below as a complement to the financial information provided in accordance

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with GAAP. However, Revenue net of purchased power expense and Revenue net of fuel expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income (Loss) Attributable to Common Shareholder

Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015. DPL s net income attributable to common shareholder for the three months ended June 30, 2016, was higher than the same period in 2015 as a result of an increase in revenue net of purchased power expense primarily resulting from customer growth and higher transmission revenue offset by increases in various operating expenses discussed below.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015. DPL s net loss attributable to common shareholder for the six months ended June 30, 2016, compared unfavorably to DPL s net income for the same period in 2015, primarily due to an increase in operating and maintenance expense due to merger-related costs.

Operating Revenue Net of Purchased Power and Fuel Expense

Operating revenues include revenue from the distribution and supply of electricity to DPL s customers within its service territories at regulated rates. Operating revenues also include 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.

Electric and natural gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All DPL customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customers choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and six months ended June 30, 2016 and 2015, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Electric	56%	57%	52%	48%
Natural Gas	39%	42%	29%	27%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at June 30, 2016 and 2015 consisted of the following:

	June 30, 2016		June 30, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	76,709	14.9%	77,004	14.9%
Natural Gas	157	0.1%	161	0.1%

Retail deliveries purchased from competitive electric generation suppliers represented 57% and 54% of DPL s retail kWh sales to Delaware customers and 52% and 48% of DPL retail kWh sales to Maryland customers for the three and six months ended June 30, 2016 and 59% and 50% and to Delaware customers and 54% and 45% and to Maryland customers for the three and six months ended June 30, 2015.

The costs related to default electricity supply are included in Purchased power and fuel. Operating revenues also include transmission enhancement credits that DPL receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

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Operating revenues also include 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.

Natural gas operating revenue includes 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.

Purchased power 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 fuel 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.

The changes in DPL s operating revenues net of purchased power and fuel expense for the three and six months ended June 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended June 30 Increase (Decrease)			**Six Months Ended June 30 Increase (Decrease)**		
	Electric	**Gas**	**Total**	**Electric**	**Gas**	**Total**
Weather	$ (1)	$ 3	$ 2	$ (8)	$ (5)	$ (13)
Volume	4		4	6	2	8
Regulatory required programs	2		2	1		1
Transmission revenue	4		4	7		7
Other	1		1	1		1
Total increase (decrease)	$ 10	$ 3	$ 13	$ 7	$ (3)	$ 4

Revenue Decoupling. 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 bill stabilization adjustment (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.

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Weather. The demand for electricity and natural gas in areas not subject to the BSA is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as favorable weather conditions because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the three months ended June 30, 2016 compared to the same period in 2015, operating revenue net of purchased power and fuel expense was higher due to the impact of favorable weather conditions in DPL s service territory. During the six months ended June 30, 2016 compared to the same period in 2015, operating revenue net of purchased power and fuel expense was lower due to the impact of unfavorable winter weather conditions in DPL s service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in DPL s electric service territory and a 30-year period in DPL s natural gas service territory. The changes in heating and cooling degree days in DPL s service territory for the three and six months ended June 30, 2016 compared to the same periods in 2015 and normal weather consisted of the following:

				% Change	
Three Months Ended June 30,	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	551	408	490	35.0%	12.4%
Cooling Degree-Days	304	418	327	(27.3)%	(7.0)%
Six Months Ended June 30,					
Heating Degree-Days	2,798	3,273	2,939	(14.5)%	(4.8)%
Cooling Degree-Days	307	418	328	(26.6)%	(6.4)%

Volume. The increase in operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three and six months ended June 30, 2016 compared to the same periods in 2015, primarily reflects the impact of moderate economic and customer growth.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing adjustments. The increase in revenue net of purchased power expense for the three and six months ended June 30, 2016 compared to the same periods in 2015 is a result of higher rates effective June 1, 2015 related to increases in transmission plant investment and operating expenses, partially offset by lower revenue related to the MAPP abandonment recovery period ending March 2016.

Operating and Maintenance Expense

	Three Months Ended June 30,		Increase (Decrease)	Six Months Ended June 30,		Increase (Decrease)
	2016	**2015**		**2016**	**2015**	
Operating and maintenance expense baseline	$ 76	$ 71	$ 5	$ 278	$ 148	$ 130
Operating and maintenance expense regulatory required programs[(a)]	2	4	(2)	5	9	(4)
Total operating and maintenance expense	$ 78	$ 75	$ 3	$ 283	$ 157	$ 126

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

The changes in operating and maintenance expense for the three and six months ended June 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)		Six Months Ended June 30, Increase (Decrease)	
Baseline				
Labor, other benefits, contracting and materials	$	(2)	$	(1)
Storm-related costs				3
Uncollectible accounts expense		(2)		(3)
Remeasurement of AMI-related regulatory asset		1		1
Deferral of merger-related costs to regulatory asset		(3)		(3)
Write-off of construction work in progress		4		4
BSC and PHISCO allocations[a]		3		19
Merger commitments[b]				104
Other		4		6
		5		130
Regulatory required programs				
Purchased power administrative costs		(2)		(4)
Total increase	$	3	$	126

(a) Primarily related to merger severance and compensation costs.
(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions.

Depreciation, Amortization and Accretion Expense

The changes in depreciation, amortization and accretion expense for the three and six months ended June 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended June 30, Increase (Decrease)		Six Months Ended June 30, Increase (Decrease)	
Depreciation expense[a]	$	2	$	4
Regulatory asset amortization[b]				1
Delaware renewable energy portfolio standards deferral		1		(3)
Total increase	$	3	$	2

(a) Depreciation expense increased due to ongoing capital expenditures.

(b) Regulatory asset amortization increased for the three and six months ended June 30, 2016 compared to the same periods in 2015 due to an EmPower Maryland surcharge rate increase effective February 2015, partially offset by lower amortization of MAPP abandonment costs.

Taxes Other Than Income

Taxes other than income for the three and six months ended June 30, 2016 compared to the same periods in 2015 increased primarily due to higher property taxes.

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Interest Expense, Net

Interest expense, net for the three and six months ended June 30, 2016 compared to the same periods in 2015 remained relatively constant.

Other, Net

Other, net for the three and six months ended June 30, 2016 remained relatively level compared to the same periods in 2015.

Effective Income Tax Rate

DPL s effective income tax rate was 40.0% and 38.5% for the three months ended June 30, 2016 and 2015, respectively. DPL s effective income tax rate was 1.6% and 39.4% for the six months ended June 30, 2016 and 2015 respectively. See Note 11 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates. As a result of the merger, DPL recorded an after-tax charge of $24 million during the six months ended June 30, 2016 as a result of assessment and remeasurement of certain federal and state uncertain tax positions.

DPL Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	% Change	Weather - Normal % Change	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	1,038	1,009	2.9%	0.4%	2,465	2,872	(14.2)%	(2.7)%
Small commercial & industrial	532	675	(21.2)%	1.5%	1,104	1,185	(6.8)%	(0.2)%
Large commercial & industrial	1,164	1,159	0.4%	0.2%	2,242	2,267	(1.1)%	(0.3)%
Public authorities & electric railroads	12	10	20.0%	(16.5)%	26	23	13.0%	(8.2)%
Total retail deliveries	2,746	2,853	(3.8)%	0.4%	5,837	6,347	(8.0)%	(1.3)%

Number of Electric Customers	As of June 30, 2016	As of June 30, 2015
Residential	454,402	453,664
Small commercial & industrial	59,904	59,466
Large commercial & industrial	1,417	1,418
Public authorities & electric railroads	643	645
Total	516,366	515,193

Electric Revenue	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	% Change	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015	% Change
Retail Sales[a]						
Residential	$ 143	$ 134	6.7%	$ 323	$ 350	(7.7)%
Small commercial & industrial	46	44	4.5%	95	94	1.1%
Large commercial & industrial	25	30	(16.7)%	50	53	(5.7)%
Public authorities & electric railroads	3	3	%	7	6	16.7%
Total retail	217	211	2.8%	475	503	(5.6)%
Other revenue[b]	38	35	8.6%	83	77	7.8%
Total electric revenue[c]	$ 255	$ 246	3.7%	$ 558	$ 580	(3.8)%

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(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from DPL and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from DPL, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.
(c) Includes operating revenues from affiliates totaling $2 million and $2 million for the three months ended June 30, 2016 and 2015, respectively, and $4 million and $3 million for the six months ended June 30, 2016 and 2015, respectively.

DPL Natural Gas Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2016	2015	% Change	Weather - Normal % Change	Six Months Ended June 30, 2016	2015	% Change	Weather - Normal % Change
Retail Deliveries								
Residential	2,072	1,731	19.7%	7.4%	8,132	9,609	(15.4)%	(3.9)%
Transportation & other	1,321	1,247	5.9%	1.1%	3,289	3,572	(7.9)%	(1)%
Total natural gas deliveries	3,393	2,978	13.9%	4.9%	11,421	13,181	(13.4)%	(3.1)%

Number of Gas Customers	As of June 30, 2016	2015
Residential	119,592	118,881
Commercial & industrial	9,669	9,597
Transportation & other	157	161
Total	129,418	128,639

Natural Gas Revenue	Three Months Ended June 30, 2016	2015	% Change	Six Months Ended June 30, 2016	2015	% Change
Retail Sales[a]						
Retail sales	$ 21	$ 20	5.0%	$ 74	$ 99	(25.3)%
Transportation & other[b]	5	5	%	11	12	(8.3)%
Total natural gas revenues	$ 26	$ 25	4.0%	$ 85	$ 111	(23.4)%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from DPL and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from DPL, revenue also reflects the cost of natural gas.
(b) Transportation and other revenue includes off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers.

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Results of Operations ACE

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015	Favorable (Unfavorable) Variance
Operating revenues	$ 270	$ 285	$ (15)	$ 561	$ 618	$ (57)
Purchased power expense	141	147	6	298	338	40
Revenue net of purchased power expense[(a)]	129	138	(9)	263	280	(17)
Other operating expenses						
Operating and maintenance	68	69	1	280	138	(142)
Depreciation, amortization and accretion	41	43	2	81	86	5
Taxes other than income	2	1	(1)	4	3	(1)
Total other operating expenses	111	113	2	365	227	(138)
Gain on sale of assets	1		1	1		1
Operating income (loss)	19	25	(6)	(101)	53	(154)
Other income and (deductions)						
Interest expense, net	(16)	(16)		(32)	(32)	
Other, net	2	1	1	5	3	2
Total other income and (deductions)	(14)	(15)	1	(27)	(29)	2
Income (loss) before income taxes	5	10	(5)	(128)	24	(152)
Income taxes	2	4	2	(31)	9	40
Net income (loss) attributable to common shareholder	$ 3	$ 6	$ (3)	$ (97)	$ 15	$ (112)

(a) ACE evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. ACE believes Revenue net of purchased power expense is a useful measurement of its performance because it provides information that can be used to evaluate its operational performance. ACE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income (Loss) Attributable to Common Shareholder

Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015. ACE s net income attributable to common shareholder for the three months ended June 30, 2016, was lower than the same period in 2015, primarily due to a decrease in operating revenue net of purchased power expense resulting from unfavorable weather-related sales and lower average customer usage.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015. ACE s net loss attributable to common shareholder for the six months ended June 30, 2016, compared unfavorably to ACE s net income for the same period in 2015, primarily due to an increase in operating and maintenance expense due to merger-related costs.

Operating Revenue Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to ACE s customers within its service territories at regulated rates. Operating revenues also include 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.

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Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All ACE customers have the choice to purchase electricity from competitive electric generation suppliers. The customer s choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and six months ended June 30, 2016, compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Electric	49%	48%	48%	46%

Retail customers purchasing electric generation from competitive electric generation suppliers at June 30, 2016 and 2015 consisted of the following:

	June 30, 2016		June 30, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	80,325	15%	80,337	15%

The costs related to default electricity supply are included in Purchased power expense. Operating revenues also include revenue from Transition Bond Charges that ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds, revenue from the resale in the PJM RTO market of energy and capacity purchased under contacts with unaffiliated NUGs, and revenue from transmission enhancement credits.

Operating revenues also include 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.

Purchased power expense 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.

The changes in ACE s operating revenue net of purchased power expense for the three and six months ended June 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Weather	$ (2)	$ (9)
Volume	(8)	(8)
Regulatory required programs	(4)	(9)
Transmission revenues	5	8
Other		1
Total decrease	$ (9)	$ (17)

Weather. The demand for electricity is affected by weather conditions. With respect to the electric business, very warm weather in summer months and very cold weather in winter months are referred to as favorable weather conditions because these weather conditions result in increased deliveries of electricity. Conversely, mild weather reduces demand. During the three and six months ended June 30, 2016 compared to the same periods in 2015, operating revenue net of purchased power and fuel expense was lower due to the impact of unfavorable weather conditions in ACE s service territory.

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For retail customers of ACE, distribution revenues are not decoupled for the distribution of electricity by ACE, and thus are subject to variability due to changes in customer consumption. Therefore, changes in customer usage (due to weather conditions, energy prices, energy savings programs or other reasons) from period to period have a direct impact on reported distribution revenue for customers in ACE s service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in ACE s service territory. The changes in heating and cooling degree days in ACE s service territory for the three and six months ended June 30, 2016 compared to the same periods in 2015 consisted of the following:

				% Change	
Three Months Ended June 30,	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	651	483	576	34.8%	13.0%
Cooling Degree-Days	258	366	285	(29.5)%	(9.5)%
Six Months Ended June 30,					
Heating Degree-Days	2,921	3,524	3,099	(17.1)%	(5.7)%
Cooling Degree-Days	261	366	286	(28.7)%	(8.7)%

Volume. The decrease in operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three and six months ended June 30, 2016 compared to the same periods in 2015, primarily reflects the impact of lower average customer usage.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the depreciation and amortization expense discussion below for additional information on included programs.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing adjustments. The increase in revenue net of purchased power expense for the three and six months ended June 30, 2016 compared to the same periods in 2015 is a result of higher rates effective June 1, 2015 related to increases in transmission plant investment and operating expenses.

Operating and Maintenance Expense

	Three Months Ended June 30,		Increase	Six Months Ended June 30,		Increase
	2016	**2015**	**(Decrease)**	**2016**	**2015**	**(Decrease)**
Operating and maintenance expense baseline	$ 67	$ 68	$ (1)	$ 278	$ 136	$ 142
Operating and maintenance expense regulatory required programs[(a)]	1	1		2	2	
Total operating and maintenance expense	$ 68	$ 69	$ (1)	$ 280	$ 138	$ 142

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

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The changes in operating and maintenance expense for the three and six months ended June 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended June 30, Increase (Decrease)		Six Months Ended June 30, Increase (Decrease)	
Baseline				
Labor, other benefits, contracting and materials	$	(5)	$	7
Storm-related costs		1		1
BSC and PHISCO allocations[a]		3		16
Uncollectible accounts expense		(1)		1
Merger commitments[b]				120
Other		1		(3)
Total (decrease) increase	$	(1)	$	142

(a) Primarily related to merger severance and compensation costs.
(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions.

Depreciation, Amortization and Accretion Expense

The changes in depreciation, amortization and accretion expense for the three and six months ended June 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended June 30, Increase (Decrease)		Six Months Ended June 30, Increase (Decrease)	
Depreciation expense[a]	$	1	$	3
Regulatory asset amortization[b]		(3)		(8)
Total decrease	$	(2)	$	(5)

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization decreased for the three and six months ended June 30, 2016 compared to the same periods in 2015 as a result of lower revenue due to a rate decrease effective October 2015 for the ACE Market Transition charge tax.

Taxes Other Than Income

Taxes other than income for the three and six months ended June 30, 2016 compared to the same periods in 2015, remained relatively constant.

Interest Expense, Net

Interest expense, net for the three and six months ended June 30, 2016 compared to the same periods in 2015 remained relatively constant.

Other, Net

Other, net for the three and six months ended June 30, 2016 compared to the same periods in 2015 increased primarily due to higher income from AFUDC equity.

Effective Income Tax Rate

ACE s effective income tax rate was 40.0% and 40.0% for the three months ended June 30, 2016 and 2015 respectively. ACE s effective income tax rate was 24.2% and 37.5% for the six months ended June 30, 2016 and

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2015 respectively. See Note 11 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates. As a result of the merger, ACE recorded an after-tax charge of $23 million during the six months ended June 30, 2016 as a result of assessment and remeasurement of certain federal uncertain tax positions.

ACE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2016	2015	% Change	Weather - Normal % Change	Six Months Ended June 30, 2016	2015	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	814	908	(10.4)%	0.2%	1,752	2,032	(13.8)%	(1.8)%
Small commercial & industrial	283	306	(7.5)%	%	572	611	(6.4)%	(0.9)%
Large commercial & industrial	853	920	(7.3)%	(0.1)%	1,673	1,736	(3.6)%	(0.5)%
Public authorities & electric railroads	9	11	(18.2)%	%	24	23	4.3%	%
Total retail deliveries	1,959	2,145	(8.7)%	0.1%	4,021	4,402	(8.7)%	(1.1)%

Number of Electric Customers	As of June 30, 2016	2015
Residential	483,044	483,024
Small commercial & industrial	60,928	60,915
Large commercial & industrial	3,806	3,859
Public authorities & electric railroads	594	549
Total	548,372	548,347

Electric Revenue	Three Months Ended June 30, 2016	2015	% Change	Six Months Ended June 30, 2016	2015	% Change
Retail Sales[a]						
Residential	$ 131	$ 147	(10.9)%	$ 281	$ 322	(12.7)%
Small commercial & industrial	39	42	(7.1)%	78	82	(4.9)%
Large commercial & industrial	50	50	%	101	99	2.0%
Public authorities & electric railroads	3	3	%	6	6	%
Total retail	223	242	(7.9)%	466	509	(8.4)%
Other revenue[b]	47	43	9.3%	95	109	(12.8)%
Total electric revenue[c]	$ 270	$ 285	(5.3)%	$ 561	$ 618	(9.2)%

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

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

(c) Includes operating revenues from affiliates totaling $1 million and $1 million for the three months ended June 30, 2016 and 2015, respectively, and $2 million and $2 million for the six months ended June 30, 2016 and 2015, respectively.

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Liquidity and Capital Resources

Exelon activity presented below includes the activity of PHI, Pepco, DPL and ACE, from the PHI Merger effective date of March 24, 2016 through June 30, 2016. Exelon prior year activity is unadjusted for the effects of the PHI Merger. Due to the application of push-down accounting to the PHI entity, PHI s activity is presented in two separate reporting periods, the legacy PHI activity through March 23, 2016 (Predecessor), and PHI activity for the remainder of the period after the PHI merger date (Successor). For each of Pepco, DPL and ACE the activity presented below include its activity for the six months ended June 30, 2016 and 2015. All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants operating and capital expenditure requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants businesses are capital intensive and require considerable capital resources. Each Registrant s access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, the Registrants have access to unsecured revolving credit facilities with aggregate bank commitments of $9 billion. In addition, Generation has $525 million in bilateral credit facilities with banks which have various expirations dates between December 2016 and May 2021. The Registrants utilize their credit facilities to support their commercial paper programs, and provide for other short-term borrowings, term loans and letters of credit. See the Credit Matters section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO, BGE, Pepco, DPL and ACE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 10 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants debt and credit agreements.

Cash Flows from Operating Activities

General

Generation s cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation s future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

The Utility Registrants cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO, BGE and DPL, natural gas distribution services. The Utility Registrants distribution services are provided to an established and diverse base of retail customers. The Utility Registrants future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 3 Regulatory Matters and 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2015 Form 10-K for further discussion of regulatory and legal proceedings and proposed legislation. See Note 7 Regulatory Matters and Note 16 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the PHI 2015 Form 10-K.

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The following table provides a summary of the major items affecting Exelon s cash flows from operations for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30, 2016[c]	Six Months Ended June 30, 2015	Variance
Net income	$ 430	$ 1,372	$ (942)
Add (subtract):			
Non-cash operating activities[a]	3,992	2,254	1,738
Pension and non-pension postretirement benefit contributions	(258)	(301)	43
Income taxes	470	247	223
Changes in working capital and other noncurrent assets and liabilities[b]	(781)	(284)	(497)
Option premiums received, net	(10)	22	(32)
Counterparty collateral received, net	710	659	51
Net cash flows provided by operations	$ 4,553	$ 3,969	$ 584

(a) Represents, when applicable, depreciation, amortization and accretion, net fair value changes related to derivatives, deferred income taxes, provision for uncollectible accounts, pension and other postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, PHI merger commitment and severance charges, and other non-cash charges. See Note 19 Supplemental Financial Information for further detail on non-cash operating activity.

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

(c) Includes PHI Consolidated activity from March 24, 2016 to June 30, 2016.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. On August 8, 2014, this funding relief was extended for five years. On November 2, 2015 the funding relief was extended for an additional three years and premiums pension plans pay to the Pension Benefit Guaranty Corporation were further increased.

OPEB funding generally follows accounting cost, subject to adjustment for other considerations such as liabilities management and regulatory implications.

To the extent interest rates decline significantly or the pension plans do not earn the expected asset return rates, annual pension contribution requirements in future years could increase. Additionally, expected contributions could change if Exelon changes its pension or OPEB funding strategy.

Tax Matters

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

In the event of a fully successful IRS challenge to Exelon s like-kind exchange position, Exelon would be required to either post a bond or pay the tax and interest for the tax years before the court to appeal the decision. If an adverse decision is reached in 2016, the potential tax and after-tax interest, exclusive of penalties, that could become payable may be as much as $870 million, of which approximately $300 million would be attributable to ComEd after consideration of Exelon s agreement to hold ComEd

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harmless from any unfavorable impacts of the after-tax interest amounts on ComEd s equity, and the balance at Exelon. The $870 million above is comprised of $1,190 million of tax and interest that could become payable in 2016, reduced by $320 million of interest benefit that will be realized subsequent to the adverse decision. It is expected that Exelon s remaining tax years affected by the litigation will be settled following a final appellate decision which could take several years.

In April of 2016, Exelon received tax refunds of approximately $460 million related to IRS positions settled in prior tax years. Of this amount, approximately $195 million of the refund is attributable to Generation and the remaining $265 million is attributable to ComEd.

State and local governments continue to face increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes or the imposition, extension or permanence of temporary tax levies.

Cash flows from operations for the six months ended June 30, 2016 and 2015 by Registrant were as follows:

	Six Months Ended June 30, 2016	**2015**
Exelon	$ 4,553	$ 3,969
Generation	2,387	2,423
ComEd	1,128	800
PECO	339	375
BGE	489	489
Pepco	365	105
DPL	220	115
ACE	208	83

	Successor	*Predecessor*	
	March 24, 2016 to June 30, 2016	**January 1, 2016 to March 23, 2016**	**Six Months Ended June 30, 2015**
PHI	$ 188	$ 264	$ 339

Changes in the Registrants cash flows from operations were generally consistent with changes in each Registrant s respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for the six months ended June 30, 2016 and 2015 were as follows:

Generation

Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on the exchange or in the OTC markets. During the six months ended June 30, 2016 and 2015, Generation had net collections of counterparty cash collateral of $720 million and $682 million, respectively, primarily due to market conditions that resulted in changes to Generation s net mark-to-market position.

During the six months ended June 30, 2016 and 2015, Generation had net (payments)/collections of approximately $(10) million and $22 million, respectively, related to purchases and sales of options. The level of option activity in a given period may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

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ComEd

During six months ended June 30, 2016 and 2015, ComEd posted approximately $10 million of cash collateral and had no change to cash collateral at PJM, respectively. ComEd s collateral posted with PJM has increased year over year due to higher RPM credit requirements and higher PJM billings. As of June 30, 2016 and 2015, ComEd had approximately $41 million and no cash collateral posted with PJM, respectively.

PHI, Pepco, DPL and ACE

During the six months ended June 30, 2016, Pepco, DPL and ACE received tax refund allocations from PHI in connection with the Global Tax Settlement of $147 million, $56 million and $167 million, respectively. See Note 11 Income Taxes of the PHI 2015 Form 10-K for additional information.

Cash Flows from Investing Activities

Cash flows used in investing activities for the six months ended June 30, 2016 and 2015 by Registrant were as follows:

	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Exelon	$ (10,877)	$ (3,546)
Generation	(2,210)	(1,850)
ComEd	(1,313)	(1,044)
PECO	(291)	(281)
BGE	(375)	(275)
Pepco	(307)	(248)
DPL	(180)	(148)
ACE	(160)	(140)

	Successor March 24, 2016 to June 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016	*Predecessor* Six Months Ended June 30, 2015
PHI	$ (350)	$ (343)	$ (553)

Generation

Generation has entered into several agreements to acquire equity interests in privately held and development stage entities which develop energy-related technologies. The agreements contain a series of scheduled investment commitments, including in-kind service contributions. There are approximately $235 million of anticipated expenditures remaining through 2018 to fund anticipated planned capital and operating needs of the associated companies. See Note 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2015 Form 10-K for further details of Generation s equity interests.

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Capital expenditures by Registrant for the six months ended June 30, 2016 and 2015 and projected amounts for the full year 2016 are as follows:

	Projected Full Year 2016[a]	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Exelon	$ 8,975	$ 4,489	$ 3,460
Generation	3,400	2,051	1,764
ComEd[b]	2,575	1,334	1,061
PECO	675	299	289
BGE	850	392	304
Pepco[c]	575	256	254
DPL[c]	325	182	154
ACE[c]	275	164	138
Other[d]	125	74	47

	Projected Full Year 2016[a]	*Successor* March 24, 2016 to June 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016	*Predecessor* Six Months Ended June 30, 2015
PHI	$ 1,175	$ 339	$ 273	$ 562

(a) Total projected capital expenditures do not include adjustments for non-cash activity.
(b) The 2016 projections include approximately $624 million of expected incremental spending pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten year period, through 2022, to modernize and storm-harden its distribution system and to implement smart grid technology.
(c) Projected capital expenditures reflect projections after March 23, 2016.
(d) Other primarily consists of corporate operations, BSC and PHISCO.

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

Generation

Approximately 32% and 36% of the projected 2016 capital expenditures at Generation are for the acquisition of nuclear fuel and growth (primarily new plant construction and distributed generation), respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that they will fund capital expenditures with internally generated funds and borrowings.

ComEd, PECO, BGE, Pepco, DPL and ACE

Approximately 86%, 96%, 100%, 100%, 100% and 100% of the projected 2016 capital expenditures at ComEd, PECO, BGE, Pepco, DPL and ACE, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd s reliability related investments required under EIMA, and the Utility Registrants construction commitments under PJM s RTEP. In addition to capital expenditures for continuing projects, ComEd s total expenditures include smart grid/smart meter technology required under EIMA and for PECO, BGE, Pepco, DPL, and ACE, include capital expenditures related to their respective smart meter programs.

The Utility Registrants as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments could require the Utility Registrants to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. In 2010, NERC provided guidance to

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transmission owners that recommended the Utility Registrants perform assessments of their transmission lines. ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd s, PECO s and BGE s forecasted 2016 capital expenditures above reflect capital spending for remediation to be completed through 2017. Pepco, DPL and ACE have substantially completed their assessments and thus do not expect significant capital expenditures related to this guidance in 2016.

The Utility Registrants anticipate that they will fund their capital expenditures with a combination of internally generated funds and borrowings and additional capital contributions from parent, including ComEd s capital expenditures associated with EIMA as further discussed in Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the six months ended June 30, 2016 and 2015 by Registrant were as follows:

	Six Months Ended June 30,	
	2016	**2015**
Exelon	$ 1,469	$ 3,713
Generation	(235)	(897)
ComEd	854	229
PECO	(140)	(98)
BGE	(118)	(254)
Pepco	64	159
DPL	(30)	35
ACE	100	58

	Successor		*Predecessor*
	March 24, 2016 to June 30, 2016	**January 1, 2016 to March 23, 2016**	**Six Months Ended June 30, 2015**
PHI	$ 137	$ 372	$ 233

Debt

See Note 10 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants debt issuances.

Dividends

Cash dividend payments and distributions during the six months ended June 30, 2016 and 2015 by Registrant were as follows:

	Six Months Ended June 30,	
	2016	**2015**
Exelon	$ 582	$ 537
Generation	111	2,262
ComEd	183	150
PECO	139	139
BGE[(a)]	96	83
Pepco	55	31

DPL	38	62
ACE	11	12

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	Successor	*Predecessor*	
	March 24, 2016 to June 30, 2016	**January 1, 2016 to March 23, 2016**	**Six Months Ended June 30, 2015**
PHI	$ 124	$	$ 137

(a) Includes dividends paid on BGE s preference stock.

Quarterly dividends declared by the Exelon Board of Directors during the six months ended June 30, 2016 and for the third quarter of 2016 were as follows:

Period	**Declaration Date**	**Shareholder of Record Date**	**Dividend Payable Date**	**Cash per Share[(a)]**
First Quarter 2016	January 26, 2016	February 12, 2016	March 10, 2016	$0.310
Second Quarter 2016	April 26, 2016	May 13, 2016	June 10, 2016	$0.318
Third Quarter 2016	July 26, 2016	August 15, 2016	September 9, 2016	$0.318

(a) Exelon s Board of Directors approved a revised dividend policy. The approved policy will raise the dividend 2.5% each year for the next three years, beginning with the June 2016 dividend and subject to Board approval.

Short-Term Borrowings

Short-term borrowings incurred (repaid) during the six months ended June 30, 2016 and 2015 by Registrant were as follows:

	Six Months Ended June 30,	
	2016	**2015**
Exelon	$ (798)	$ 94
Generation	179	15
ComEd	(259)	199
BGE	(2)	(120)
Pepco	(64)	(104)
DPL	(105)	(76)
ACE	(5)	91

	Successor	*Predecessor*	
	March 24, 2016 to June 30, 2016	**January 1, 2016 to March 23, 2016**	**Six Months Ended June 30, 2015**
PHI	$ (837)	$ 379	$ 69

Contributions from Parent/Member

Contributions received from Parent/Member for the six months ended June 30, 2016 and 2015 by Registrant were as follows:

	Six Months Ended June 30,	
	2016	**2015**
Generation	$ 45	$
ComEd	113[(a)]	45[(a)]

BGE	21[a]	
Pepco	187[b]	112[b]
DPL	113[b]	75[b]
ACE	139[b]	

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	Successor	Predecessor	
		January 1, 2016	
	March 24, 2016 to June 30, 2016	to March 23, 2016	Six Months Ended June 30, 2015
PHI	$ 1,088[(a)]	$	$

(a) Contribution paid by Exelon.

(b) Contribution paid by PHI.

Pursuant to the orders approving the merger, Exelon made equity contributions of $73 million, $46 million and $49 million to Pepco, DPL and ACE, respectively, in the second quarter of 2016 to fund the after-tax amount of the customer bill credit and the customer base rate credit.

Redemptions of Preference Stock

On July 3, 2016, BGE redeemed all 400,000 shares of its outstanding 7.125% Cumulative Preference Stock, 1993 Series and all 600,000 shares of its outstanding 6.99% Cumulative Preference Stock, 1995 Series for $100 million, plus accrued and unpaid dividends. Following this redemption, BGE has $90 million of cumulative preference stock remaining, which will likely be redeemed by the end of 2016. See Note 17 Earnings Per Share and Equity of the Combined Notes to Consolidated Financial Statements for further details.

Other

For the six months ended June 30, 2016, other financing activities primarily consist of debt issuance costs. See Note 10 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further details of the Registrants debt issuances.

Credit Matters

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $9.5 billion in aggregate total commitments of which $7.8 billion was available as of June 30, 2016, and of which no financial institution has more than 7% of the aggregate commitments for the Registrants. The Registrants had access to the commercial paper market during the second quarter of 2016 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A. RISK FACTORS of the Exelon 2015 Form 10-K for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of June 30, 2016, it would have been required to provide incremental collateral of $1.8 billion to meet collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of $4.2 billion.

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The following table presents the incremental collateral that each utility registrant would have been required to provide in the event each utility registrant lost its investment grade credit rating at June 30, 2016 and available credit facility capacity prior to any incremental collateral at June 30, 2016:

	PJM Credit Policy Collateral	Other Incremental Collateral Required (a)	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 3	$	$ 998
PECO	2	26	598
BGE	2	31	600
Pepco			300
DPL	3	9	300
ACE			299

(a) Represents incremental collateral related to natural gas procurement contracts.

Exelon Credit Facilities

Exelon, ComEd, and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. PHI meets its short-term liquidity requirements primarily through the issuance of short-term notes and the Exelon intercompany money pool. Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and short-term notes. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

The following table reflects the Registrants commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at June 30, 2016:

Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size(a)(b)	Outstanding Commercial Paper at June 30, 2016	Average Interest Rate on Commercial Paper Borrowings for the Six Months Ended June 30, 2016
Exelon Corporate	$ 600	$	0.70%
Generation	5,300		1.01%
ComEd	1,000	35	0.79%
PECO	600		%
BGE	600	208	0.78%
Pepco	500		0.67%
DPL	500		0.69%
ACE	350		0.65%

(a) Excludes $525 million bilateral credit facilities that do not back Generation s commercial paper program.

(b) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd s, PECO s and BGE s service territories. These facilities expire on October 14, 2016. These facilities are solely utilized to issue letters of credit. As of June 30, 2016, letters of credit issued under these agreements for Generation, ComEd, PECO and BGE totaled $7 million, $14 million, $21 million and $2 million, respectively.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its commercial paper outstanding does not reduce available capacity under a Registrant s credit facility, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available

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capacity under its credit facility. At June 30, 2016, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit facilities:

Credit Agreements

					Available Capacity at June 30, 2016	
Borrower	**Facility Type**	**Aggregate Bank Commitment[(a)(b)(c)]**	**Facility Draws**	**Outstanding Letters of Credit**	**Actual**	**To Support Additional Commercial Paper[(d)]**
Exelon Corporate	Syndicated Revolver	$ 600	$	$ 29	$ 571	$ 571
Generation[(e)]	Syndicated Revolver	5,300		1,194	4,106	4,106
Generation	Bilaterals	525	150	319	56	
ComEd	Syndicated Revolver	1,000		2	998	963
PECO	Syndicated Revolver	600		2	598	598
BGE	Syndicated Revolver	600			600	392
Pepco	Syndicated Revolver	300			300	300
DPL	Syndicated Revolver	300			300	300
ACE	Syndicated Revolver	300		1	299	299

(a) Excludes $123 million of credit facility agreements arranged at minority and community banks at Generation, ComEd, PECO and BGE. These facilities expire on October 14, 2016. These facilities are solely utilized to issue letters of credit. As of June 30, 2016, letters of credit issued under these agreements for Generation, ComEd, PECO and BGE totaled $7 million, $14 million, $21 million and $2 million, respectively.
(b) Pepco, DPL and ACE s revolving credit facility is subject to available borrowing capacity. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by each of Pepco, DPL or ACE may not exceed $900 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 borrowing reallocations may not exceed eight per year during the term of the facility
(c) Excludes nonrecourse debt letters of credit, see Note 14 Debt and Credit Agreements in the Exelon 2015 Form 10-K for further information on Continental Wind nonrecourse debt.
(d) Excludes $525 million bilateral credit facilities that do not back Generation s commercial paper program.
(e) Excludes ExGen Texas Power Financing s $20 million of borrowed debt on its revolving credit facility.

As of June 30, 2016, there was $150 million of borrowings under Generation s bilateral credit facilities.

Borrowings under Exelon Corporate s, Generation s, ComEd s, PECO s, BGE s, Pepco s, DPL s, and ACE s revolving credit agreements bear intere at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular Registrant s credit rating. The adders for the prime based borrowings and LIBOR-based borrowings are presented in the following table:

	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**Pepco**	**DPL**	**ACE**
Prime based borrowings	27.5	27.5	7.5	0.0	0.0	7.5	7.5	7.5
LIBOR-based borrowings	127.5	127.5	107.5	90.0	100.0	107.5	107.5	107.5

The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 90 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower.

Each revolving credit agreement for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The following table summarizes the minimum thresholds reflected in the credit agreements for the six months ended June 30, 2016:

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

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At June 30, 2016, the interest coverage ratios at Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE were as follows:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Interest coverage ratio	8.92	12.94	7.55	8.94	10.76	5.63	7.56	4.70

An event of default under Exelon, Generation, ComEd, PECO or BGE s indebtedness will not constitute an event of default under any of the others credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation will constitute an event of default under the Exelon Corporate credit facility. An event of default under Pepco, DPL or ACE s indebtedness will not constitute an event of default under any of the others credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $50 million in the aggregate will constitute an event of default under the credit facility.

The absence of a material adverse change in Exelon s or 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.

Security Ratings

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

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

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, both Exelon and PHI operate intercompany money pools. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of June 30, 2016, are presented in the following table:

Exelon Intercompany Money Pool	**During the Three Months Ended June 30, 2016**		**As of June 30, 2016**
Contributed (borrowed)	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Exelon Corporate	$ 1,325	n/a	$ 1,121
Generation		1,143	(817)
PECO	161		
BSC		379	(333)
PHI Corporate[(a)]	n/a	36	(34)
PCI[(a)]	63		63

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(a) As a result of the merger, PHI Corporate and PCI began to participate in the Exelon Intercompany Money Pool effective March 24, 2016.

PHI Intercompany Money Pool	During the Three Months Ended June 30, 2016		As of June 30, 2016
Contributed (borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
PHI Corporate	$ 152	n/a	$ 25
Pepco			
DPL			
ACE			
PHISCO		152	(25)

Investments in Nuclear Decommissioning Trust Funds

Exelon, Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation s NDT fund investment policy. Generation s and CENG s investment policies establish limits on the concentration of holdings in any one company and also in any one industry. See Note 12 Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC s minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements

Exelon, Generation, ComEd, PECO and BGE have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in May 2017. PHI, Pepco, DPL and ACE have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in August 2016. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations

Generation, ComEd, PECO, BGE, Pepco, DPL and ACE are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	Short-term Financing Authority[(a)]			Long-term Financing Authority		
	Commission	Expiration Date	Amount (in millions)	Commission	Expiration Date	Amount (in millions)
ComEd[(b)]	FERC	December 31, 2017	$2,500	ICC	2019	$2,383
PECO	FERC	December 31, 2017	1,500	PAPUC	December 31, 2018	1,900
BGE	FERC	December 31, 2017	700	MDPSC	N/A	850
Pepco	FERC	June 30, 2018	500	MDPSC / DCPSC	September 25, 2017	550
DPL	FERC	June 30, 2018	500	MDPSC / DPSC	December 31, 2017	300
ACE	NJPU	January 1, 2018	350	NJBPU	December 31, 2017	300

(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.
(b) ComEd had $1,565 million available in long-term debt refinancing authority and $818 million available in new money long term debt financing authority from the ICC as of June 30, 2016 and has an expiration date of June 1, 2019 and March 1, 2019, respectively.

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Contractual Obligations and Off-Balance Sheet Arrangements

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments triggered by future events. See Note 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in the Exelon 2015 Form 10-K and Note 16 Commitments and Contingencies of the PHI 2015 Form 10-K for discussion of the Registrants commitments.

Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have obligations related to contracts for the purchase of power and fuel supplies, and ComEd, PECO, and BGE have obligations related to their financing trusts. The power and fuel purchase contracts and the financing trusts have been considered for consolidation in the Registrants respective financial statements pursuant to the authoritative guidance for VIEs. See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for further information.

For an in-depth discussion of the Registrants contractual obligations and off-balance sheet arrangements, see Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Obligations and Off-Balance Sheet Arrangements in the Exelon 2015 Form 10-K and Management s Discussion and Analysis of Financial Condition and Results of Operations Contractual Obligations and Commercial Commitments and Management s Discussion and Analysis of Financial Condition and Results of Operations Guarantees, Indemnifications and Off-Balance Sheet Arrangements in the PHI 2015 Form 10-K.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon s RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities. The following discussion serves as an update to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of the Registrants 2015 Annual Report on Form 10-K incorporated herein by reference.

Commodity Price Risk (All Registrants)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation s owned or contracted generation supply in excess of Generation s obligations to customers, including portions of the Utility Registrants retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including forwards, futures, swaps and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2016 through 2018.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation s owned and contracted generation positions which have not been hedged. Exelon s hedging program involves the hedging of commodity risk for Exelon s expected generation, typically on a ratable basis over a three-year period. As of June 30, 2016, the proportion of expected generation hedged is 97%-100%, 78%-81% and 47%-50% for 2016, 2017 and 2018, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation s sales to the Utility Registrants to serve their retail load.

A portion of Generation s hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation s entire non-proprietary trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on June 30, 2016 market conditions and hedged position would be an increase in pre-tax net income of approximately $5 million for 2016 and decreases of $205 million and $475 million, respectively, for 2017 and 2018. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation s portfolio.

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Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon s RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon s RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 1,289 GWhs and 2,509 GWhs for the three and six months ended June 30, 2016, respectively, and 1,657 GWhs and 3,465 GWhs for the three and six months ended June 30, 2015, respectively, are a complement to Generation s energy marketing portfolio, but represent a small portion of Generation s overall revenue from energy marketing activities. Proprietary trading portfolio activity for the six months ended June 30, 2016 resulted in pre-tax gains of $6 million due to net mark-to-market gains of $2 million and $4 million realized gains. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period and a one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $0.2 million of exposure during the quarter. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation s total Revenue net of purchase power and fuel expense from continuing operations for the six months ended June 30, 2016 of $4,309 million.

Fuel Procurement. Generation procures natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation s procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 58% of Generation s uranium concentrate requirements from 2016 through 2020 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon s and Generation s results of operations, cash flows and financial positions. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information regarding uranium and coal supply agreement matters.

ComEd

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC s Order on December 19, 2012, ComEd s commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC s December 18, 2013 Order approved the reduction of ComEd s commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements. PECO has certain full requirements

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contracts which are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge its long-term price risk in the natural gas market. PECO s hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE s MDPSC-approved SOS program. BGE s full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result, are accounted for on an accrual basis of accounting. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE s financial position. However, under BGE s market-based rates incentive mechanism, BGE s actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE s actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Pepco

Pepco has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and DCPSC. The SOS rates charged recover Pepco s wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for residential and commercial rate classes. Pepco s price risk related to electric supply procurement is limited. Pepco locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of Pepco s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other Pepco full requirements contracts are not derivatives.

Pepco does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

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DPL

DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the DPSC. The SOS rates charged recover DPL s wholesale power supply costs and include a Reasonable Allowance for Retail Margin (RARM). The RARM includes a fixed annual margin of approximately $2.75 million, plus an incremental cost component and a cash working capital allowance. DPL s price risk related to electric supply procurement is limited. DPL locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of DPL s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

DPL provides natural gas to its customers under a GCR mechanism approved by the DPSC. The demand portion of the GCR is based upon DPL s firm transportation and storage contracts. DPL has firm deliverability of swing and seasonal storage; a liquefied natural gas facility and firm transportation capacity to meet customer demand and provide a reserve margin. The commodity portion of the GCR includes a commission approved hedging program which is intended to reduce gas commodity price volatility while limiting the firm natural gas customers exposure to adverse changes in the market price of natural gas.

DPL does not enter into derivatives for speculative or proprietary trading purposes. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

ACE

ACE has contracts to procure BGS electric supply that are executed through a competitive procurement process approved by the NJBPU. The BGS rates charged recover ACE s wholesale power supply costs. ACE does not make any profit or incur any loss on the supply component of the BGS it supplies to customers. ACE s price risk related to electric supply procurement is limited. ACE locks in fixed prices for all of its BGS requirements through full requirements contracts. ACE s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other ACE full requirements contracts are not derivatives.

ACE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

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

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The following table provides detail on changes in Exelon s, Generation s, ComEd s, PHI s and DPL s commodity mark-to-market net asset or liability balance sheet position from December 31, 2015 to June 30, 2016. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of June 30, 2016 and December 31, 2015.

	Generation	ComEd	DPL[(a)]	Exelon[(b)]
Total mark-to-market energy contract net assets (liabilities) at December 31, 2015[(c)]	$ 1,753	$ (247)	$	$ 1,506
Total change in fair value during 2016 of contracts recorded in results of operations	(30)			(30)
Reclassification to realized at settlement of contracts recorded in results of operations	(160)			(160)
Changes in fair value energy derivatives[(d)]		26	3	28
Changes in allocated collateral	(713)		(3)	(715)
Changes in net option premium paid/(received)	10			10
Option premium amortization	17			17
Upfront payment amortizations[(e)]	17			17
Total mark-to-market energy contract net assets (liabilities) at June 30, 2016[(c)]	$ 894	$ (221)	$	$ 673

(a) As of June 30, 2016 and December 31, 2015, PHI s and DPL s mark-to-market derivative asset was fully collateralized resulting in a zero balance. For the predecessor period of January 1, 2016 to March 23, 2016, PHI recorded a $1 million increase in fair value and $1 million decrease in allocated collateral related to the exchange-traded futures.

(b) As a result of the merger, Exelon amounts include PHI and DPL activity from March 24, 2016 to June 30, 2016. For the successor period of March 24, 2016 to June 30, 2016, there was a $2 million increase in fair value and $2 million decrease in allocated collateral related to the exchange-traded futures.

(c) Amounts are shown net of collateral paid to and received from counterparties.

(d) For ComEd and DPL, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of June 30, 2016, ComEd recorded a $221 million regulatory asset related to its mark-to-market derivative liabilities with unaffiliated suppliers. For the six months ended June 30, 2016, ComEd also recorded $15 million of decreases in fair value and realized losses due to settlements of $11 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers. As of June 30, 2016, DPL recorded a $1 million regulatory liability related to its mark-to-market derivative liabilities.

(e) Includes derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums.

Fair Values. The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 8 Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

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Exelon

	Maturities Within						
	2016	**2017**	**2018**	**2019**	**2020**	**2021 and Beyond**	**Total Fair Value**
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$ 21	$ 40	$ (21)	$ (25)	$ (6)	$ 1	$ 10
Prices provided by external sources (Level 2)	146	139	(6)	(6)	2		275
Prices based on model or other valuation methods (Level 3)[c]	202	248	68	(28)	(17)	(85)	388
Total	$ 369	$ 427	$ 41	$ (59)	$ (21)	$ (84)	$ 673

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $521 million at June 30, 2016.
(c) Includes ComEd s net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2016	**2017**	**2018**	**2019**	**2020**	**2021 and Beyond**	**Total Fair Value**
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$ 21	$ 40	$ (21)	$ (25)	$ (6)	$ 1	$ 10
Prices provided by external sources (Level 2)	146	139	(6)	(6)	2		275
Prices based on model or other valuation methods (Level 3)	211	266	85	(11)		58	609
Total	$ 378	$ 445	$ 58	$ (42)	$ (4)	$ 59	$ 894

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $521 million at June 30, 2016.

ComEd

	Maturities Within						
	2016	**2017**	**2018**	**2019**	**2020**	**2021 and Beyond**	**Total Fair Value**
Commodity derivative contracts[a]:							
Prices based on model or other valuation methods (Level 3)	$ (9)	$ (18)	$ (17)	$ (17)	$ (17)	$ (143)	$ (221)

(a) Represents ComEd s net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral and Contingent Related Features (All Registrants)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented

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by the fair value of contracts at the reporting date. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk, collateral and contingent related features.

Generation

The following tables provide information on Generation s credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 2016. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company s credit risk by credit rating of the counterparties. The figures in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of $26 million, $40 million, $36 million, $50 million, $15 million, and $8 million as of June 30, 2016, respectively.

Rating as of June 30, 2016	Total Exposure Before Credit Collateral	Credit Collateral[(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 965	$ 12	$ 953	1	$ 356
Non-investment grade	55	24	31		
No external ratings					
Internally rated investment grade	373	1	372		
Internally rated non-investment grade	46	7	39		
Total	$ 1,439	$ 44	$ 1,395	1	$ 356

	Maturity of Credit Risk Exposure			
Rating as of June 30, 2016	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 703	$ 255	$ 7	$ 965
Non-investment grade	42	13		55
No external ratings				
Internally rated investment grade	316	36	21	373
Internally rated non-investment grade	44	2		46
Total	$ 1,105	$ 306	$ 28	$ 1,439

Net Credit Exposure by Type of Counterparty	As of June 30, 2016
Financial institutions	$ 96
Investor-owned utilities, marketers, power producers	573
Energy cooperatives and municipalities	696
Other	30
Total	$ 1,395

(a) As of June 30, 2016, credit collateral held from counterparties where Generation had credit exposure included $9 million of cash and $35 million of letters of credit.

ComEd, PECO and BGE

There have been no significant changes or additions to ComEd s, PECO s, or BGE s exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon s 2015 Annual Report on Form 10-K.

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See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

PHI, Pepco, DPL and ACE

There have been no significant changes or additions to PHI s, Pepco s, DPL s or ACE s exposures to credit risk as described in ITEM 1A. RISK FACTORS of PHI s 2015 Annual Report on Form 10-K.

See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

Collateral (All Registrants)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, natural gas and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation s net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation transacts output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon s and Generation s results of operations, cash flows and financial position. As market prices rise above or fall below contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Liquidity and Capital Resources Credit Matters Exelon Credit Facilities for additional information.

As of June 30, 2016, Generation had cash collateral of $548 million posted and cash collateral held of $14 million for external counterparties with derivative positions, of which $521 million and $3 million in net cash collateral deposits were offset against energy derivative and interest rate and foreign exchange derivative related to underlying energy contracts, respectively. As of June 30, 2016, $10 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives or as of the balance sheet date there were no positions to offset. See Note 18 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of June 30, 2016, ComEd held $1 million in collateral from suppliers in association with energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for renewable energy contracts. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements in this report and Note 3 Regulatory Matters of the 2015 Exelon Form 10-K for additional information.

PECO

As of June 30, 2016, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of June 30, 2016, BGE was not required to post collateral under its natural gas procurement contracts nor was it holding collateral under its electric supply and natural gas procurement contracts. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Pepco

Pepco is not required to post collateral under its energy procurement contracts. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

DPL

DPL is not required to post collateral under its energy procurement contracts. As of June 30, 2016, DPL was not required to post collateral under its natural gas procurement contracts. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

ACE

ACE is not required to post collateral under its energy procurement contracts. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

RTOs and ISOs (All Registrants)

Generation, ComEd, PECO, BGE, Pepco, DPL and ACE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon, Generation, PHI and DPL)

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. DPL enters into commodity transactions on ICE. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

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Long-Term Leases (Exelon)

On March 31, 2016, UII and MEAG finalized an agreement to terminate the MEAG Headleases, the MEAG Leases, and other related agreements prior to their expiration dates. As a result of the lease termination, UII received an early termination payment of $360 million from MEAG and wrote-off the $356 million net investment in the MEAG Headleases and the Leases. The transaction resulted in a pre-tax gain of $4 million which is reflected in Operating and maintenance expense in Exelon s Consolidated Statements of Operations and Comprehensive Income. See Note 6 Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for additional information.

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO, BGE and PHI)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Exelon registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At June 30, 2016, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $764 million and $674 million of notional amounts of floating-to-fixed hedges outstanding, respectively. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $3 million decrease in Exelon Consolidated pre-tax income for the six months ended June 30, 2016. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation s nuclear plants. As of June 30, 2016, Generation s decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation s NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $485 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

Item 4. Controls and Procedures

During the second quarter of 2016, each of Exelon s, Generation s, ComEd s, PECO s, BGE s, PHI s, Pepco s, DPL s and ACE s manageme including its principal executive officer and principal financial officer, evaluated its disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in its periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by all Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to Exelon s management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded,

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processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC s rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of June 30, 2016, the principal executive officer and principal financial officer of each of Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE concluded that such Registrant s disclosure controls and procedures were effective to accomplish its objectives. All Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. On March 23, 2016, the merger between Exelon and PHI closed. Exelon is currently in the process of integrating PHI s operations, processes and internal controls. There have been no changes in internal control over financial reporting that occurred during the second quarter of 2016, other than changes resulting from the PHI Merger, that have materially affected, or are reasonably likely to materially affect, any of Exelon s, Generation s, ComEd s, PECO s, BGE s , PHI s, Pepco s, DPL s and ACE internal control over financial reporting. See Note 4 Mergers, Acquisitions and Dispositions of the Combined Notes to the Consolidated Financial Statements for further information regarding the PHI acquisition. Exelon s management expects that the controls over financial reporting associated with PHI, Pepco, DPL and ACE from the date of the merger forward will be covered in the year-end assessment.

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PART II OTHER INFORMATION

Item 1 Legal Proceedings

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see (a) ITEM 3. LEGAL PROCEEDINGS of Exelon s 2015 Form 10-K, (b) ITEM 3. LEGAL PROCEEDINGS of PHI s 2015 Form 10-K and (c) Notes 5 Regulatory Matters and 18 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

Item 1A Risk Factors

Risks Related to Exelon

Exclusive of the *Risks Related to the Pending Merger with PHI* described in Exelon s 2015 Form 10-K in ITEM 1A. RISK FACTORS, Exelon is, and will continue to be, subject to the risks described in Exelon s and PHI s 2015 Form 10-K in (a) ITEM 1A. RISK FACTORS, (b) ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS and (c) ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA: Note 23 of the Combined Notes to Consolidated Financial Statements in Exelon s 2015 Form 10-K and Note 16 of the Notes to Consolidated Financial Statements in PHI s 2015 Form 10-K. As a result of the merger with PHI that closed on March 23, 2016 Exelon is subject to additional risks related to the merger as described below.

Risks Related to the PHI Merger

The merger may not achieve its anticipated results, and Exelon may be unable to integrate the operations of PHI in the manner expected.

Exelon and PHI entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Exelon and PHI can be integrated in an efficient, effective and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of Exelon s businesses, processes and systems or inconsistencies in standards, controls, procedures, practices and policies, any of which could adversely affect the combined company s ability to achieve the anticipated benefits of the merger as and when expected. Exelon may have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve these anticipated benefits could result in increased costs and could adversely affect Exelon s future business, financial condition, operating results and prospects.

The merger may not be accretive to earnings and may cause dilution to Exelon s earnings per share, which may negatively affect the market price of Exelon s common stock.

The timing and amount of accretion expected could be significantly adversely affected by a number of uncertainties, including market conditions, risks related to Exelon s businesses and whether the business of PHI is integrated in an efficient and effective manner. Exelon also could encounter additional transaction and integration-related costs, may fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect preliminary estimates. Any of these factors could cause a decrease in Exelon s adjusted earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of Exelon s common stock.

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Exelon may incur unexpected transaction fees and merger-related costs in connection with the merger.

Exelon expects to incur a number of non-recurring expenses associated with completing the merger, as well as expenses related to combining the operations of the two companies. Exelon may incur additional unanticipated costs in the integration of the businesses of Exelon and PHI. Although Exelon expects that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction and merger-related costs over time, the combined company may not achieve this net benefit in the near term, or at all.

Exelon may encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals for the PHI Merger.

As a result of the process to obtain regulatory approvals required for the PHI Merger, Exelon is committed to various programs, contributions and investments in several settlement agreements and regulatory approval orders. It is possible that Exelon may encounter delays, unexpected difficulties, or additional costs in meeting these commitments in compliance with the terms of the relevant agreements and orders. Failure to fulfill the commitments in accordance with their terms could result in increased costs or result in penalties or fines that could adversely affect Exelon s financial position and operating results.

Item 4 Mine Safety Disclosures
Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE

Not applicable to the Registrants.

Item 6 Exhibits

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

Exhibit No.	**Description**
4.1	Supplemental Indenture dated as of June 15, 2016 from ComEd to BNY Mellon Trust Company of Illinois, as trustee, and D. G. Donovan, as co-trustee (File No. 001-01839, Form 8-K dated June 27, 2016, Exhibit 4.1)
10.1	Amendment No. 7 to Credit Agreement, dated as of March 23, 2011, among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated May 27, 2016, Exhibit 99.1)
10.2	Amendment No. 7 to Credit Agreement, dated as of March 23, 2011, among Exelon Generation Company, LLC, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 333-85496, Form 8-K dated May 27, 2016, Exhibit 99.2)
10.3	Amendment No. 4 to Credit Agreement, dated as of March 26, 2012, among Commonwealth Edison Company, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-01839, Form 8-K dated May 27, 2016, Exhibit 99.3)

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Exhibit No.	**Description**
10.4	Amendment No. 6 to Credit Agreement, dated as of March 23, 2011, among PECO Energy Company, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 000-16844, Form 8-K dated May 27, 2016, Exhibit 99.4)
10.5	Amendment No. 5 to Credit Agreement, dated as of March 23, 2011, among Baltimore Gas and Electric Company, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-01910, Form 8-K dated May 27, 2016, Exhibit 99.5)
10.6	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of August 1, 2011, among Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, as Borrowers, the various financial institutions named therein, as Lenders, and Wells Fargo Bank, National Association, as Administrative Agent (File No. 001-31403, Form 8-K dated May 27, 2016, Exhibit 99.6)
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2016 filed by the following officers for the following companies:

31-1	Filed by Christopher M. Crane for Exelon Corporation
31-2	Filed by Jonathan W. Thayer for Exelon Corporation
31-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
31-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
31-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	Filed by Craig L. Adams for PECO Energy Company
31-8	Filed by Phillip S. Barnett for PECO Energy Company
31-9	Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
31-10	Filed by David M. Vahos for Baltimore Gas and Electric Company
31-11	Filed by David M. Velazquez for Pepco Holdings LLC
31-12	Filed by Donna J. Kinzel for Pepco Holdings LLC
31-13	Filed by David M. Velazquez for Potomac Electric Power Company
31-14	Filed by Donna J. Kinzel for Potomac Electric Power Company
31-15	Filed by David M. Velazquez for Delmarva Power & Light Company
31-16	Filed by Donna J. Kinzel for Delmarva Power & Light Company
31-17	Filed by David M. Velazquez for Atlantic City Electric Company
31-18	Filed by Donna J. Kinzel for Atlantic City Electric Company

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Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2016 filed by the following officers for the following companies:

32-1	Filed by Christopher M. Crane for Exelon Corporation
32-2	Filed by Jonathan W. Thayer for Exelon Corporation
32-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
32-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
32-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
32-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32-7	Filed by Craig L. Adams for PECO Energy Company
32-8	Filed by Phillip S. Barnett for PECO Energy Company
32-9	Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
32-10	Filed by David M. Vahos for Baltimore Gas and Electric Company
32-11	Filed by David M. Velazquez for Pepco Holdings LLC
32-12	Filed by Donna J. Kinzel for Pepco Holdings LLC
32-13	Filed by David M. Velazquez for Potomac Electric Power Company
32-14	Filed by Donna J. Kinzel for Potomac Electric Power Company
32-15	Filed by David M. Velazquez for Delmarva Power & Light Company
32-16	Filed by Donna J. Kinzel for Delmarva Power & Light Company
32-17	Filed by David M. Velazquez for Atlantic City Electric Company
32-18	Filed by Donna J. Kinzel for Atlantic City Electric Company

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SIGNATURES

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON CORPORATION

/s/ CHRISTOPHER M. CRANE Christopher M. Crane President and Chief Executive Officer (Principal Executive Officer) and Director	/s/ JONATHAN W. THAYER Jonathan W. Thayer Senior Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ DUANE M. DESPARTE Duane M. DesParte Senior Vice President and Corporate Controller (Principal Accounting Officer)	

August 9, 2016

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON GENERATION COMPANY, LLC

/s/ KENNETH W. CORNEW Kenneth W. Cornew President and Chief Executive Officer (Principal Executive Officer)	/s/ BRYAN P. WRIGHT Bryan P. Wright Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ MATTHEW N. BAUER Matthew N. Bauer Vice President and Controller (Principal Accounting Officer)	

August 9, 2016

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

COMMONWEALTH EDISON COMPANY

/s/ ANNE R. PRAMAGGIORE Anne R. Pramaggiore	/s/ JOSEPH R. TRPIK, JR. Joseph R. Trpik, Jr.

President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and
(Principal Executive Officer)	Treasurer
	(Principal Financial Officer)
/s/ GERALD J. KOZEL Gerald J. Kozel Vice President and Controller	
(Principal Accounting Officer)	

August 9, 2016

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Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PECO ENERGY COMPANY

/s/ CRAIG L. ADAMS
Craig L. Adams
President and Chief Executive Officer

(Principal Executive Officer)

/s/ PHILLIP S. BARNETT
Phillip S. Barnett
Senior Vice President, Chief Financial Officer and

Treasurer

(Principal Financial Officer)

/s/ SCOTT A. BAILEY
Scott A. Bailey
Vice President and Controller

(Principal Accounting Officer)

August 9, 2016

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ CALVIN G. BUTLER, JR.
Calvin G. Butler, Jr.
Chief Executive Officer

(Principal Executive Officer)

/s/ DAVID M. VAHOS
David M. Vahos
Senior Vice President, Chief Financial Officer and

Treasurer

(Principal Financial Officer)

/s/ ANDREW W. HOLMES
Andrew W. Holmes
Vice President and Controller

(Principal Accounting Officer)

August 9, 2016

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PEPCO HOLDINGS LLC

/s/ DAVID M. VELAZQUEZ
David M. Velazquez

/s/ DONNA J. KINZEL
Donna J. Kinzel

President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and
(Principal Executive Officer)	Treasurer
	(Principal Financial Officer)

/s/ Robert M. Aiken
Robert M. Aiken
Vice President and Controller

(Principal Accounting Officer)

August 9, 2016

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Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

POTOMAC ELECTRIC POWER COMPANY

/s/ David M. Velazquez
David M. Velazquez
President and Chief Executive Officer
(Principal Executive Officer)

/s/ Donna J. Kinzel
Donna J. Kinzel
Senior Vice President, Chief Financial Officer and
Treasurer
(Principal Financial Officer)

/s/ Robert M. Aiken
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)

August 9, 2016

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DELMARVA POWER & LIGHT COMPANY

/s/ David M. Velazquez
David M. Velazquez
President and Chief Executive Officer
(Principal Executive Officer)

/s/ Donna J. Kinzel
Donna J. Kinzel
Senior Vice President, Chief Financial Officer and
Treasurer
(Principal Financial Officer)

/s/ Robert M. Aiken
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)

August 9, 2016

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ATLANTIC CITY ELECTRIC COMPANY

/s/ David M. Velazquez
David M. Velazquez
President and Chief Executive Officer
(Principal Executive Officer)

/s/ Donna J. Kinzel
Donna J. Kinzel
Senior Vice President, Chief Financial Officer and
Treasurer

(Principal Financial Officer)

/s/ Robert M. Aiken
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)

August 9, 2016

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