UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

November 2, 2017

Date of Report (Date of earliest event reported)

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** **(a Maryland corporation)** 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201 (410) 234-5000	52-0280210
001-31403	**PEPCO HOLDINGS LLC** **(a Delaware limited liability company)** 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	52-2297449
001-01072	**POTOMAC ELECTRIC POWER COMPANY** **(a District of Columbia and Virginia corporation)** 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	53-0127880

001-01405	**DELMARVA POWER & LIGHT COMPANY** **(a Delaware and Virginia corporation)** 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	51-0084283
001-03559	**ATLANTIC CITY ELECTRIC COMPANY** **(a New Jersey corporation)** 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	21-0398280

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether any of the registrants are emerging growth companies as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if any of the registrants have elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Section 2 - Financial Information
Item 2.02. Results of Operations and Financial Condition.
Section 7 - Regulation FD
Item 7.01. Regulation FD Disclosure.

On November 2, 2017, Exelon Corporation (Exelon) announced via press release its results for the third quarter ended September 30, 2017. A copy of the press release and related attachments is attached hereto as Exhibit 99.1. Also attached as Exhibit 99.2 to this Current Report on Form 8-K are the presentation slides to be used at the third quarter 2017 earnings conference call. This Form 8-K and the attached exhibits are provided under Items 2.02, 7.01 and 9.01 of Form 8-K and are furnished to, but not filed with, the Securities and Exchange Commission.

Exelon has scheduled the conference call for 9:00 AM CT (10:00 AM ET) on November 2, 2017. The call-in number in the U.S. and Canada is 800-690-3108, and the international call-in number is 973-935-8753. If requested, the conference ID number is 44852720. Media representatives are invited to participate on a listen-only basis. The call will be web-cast and archived on Exelon's Web site: www.exeloncorp.com. (Please select the Investors page.)

Telephone replays will be available until November 16, 2017. The U.S. and Canada call-in number for replays is 855-859-2056, and the international call-in number is 404-537-3406. The conference ID number is 44852720.

Section 9 - Financial Statements and Exhibits
Item 9.01. Financial Statements and Exhibits

(d) Exhibits.

Exhibit No.	Description
99.1	Press release and earnings release attachments
99.2	Earnings conference call presentation slides

* * * * *

This combined Current Report on Form 8-K is being furnished separately by Exelon, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC (PHI), Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants). Information contained herein relating to any individual Registrant has been furnished by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

This report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants) include those factors discussed herein, as well as the items discussed in (1) the Registrants' 2016 Annual Report on 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 24, Commitments and Contingencies; (2) the Registrants' Third Quarter 2017 Quarterly Report on Form 10-Q (to be filed on November 2, 2017) in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18, Commitments and Contingencies; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this report.

SIGNATURES

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

EXELON CORPORATION

/s/ Jonathan W. Thayer

Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer
Exelon Corporation

EXELON GENERATION COMPANY, LLC

/s/ Bryan P. Wright

Bryan P. Wright
Senior Vice President and Chief Financial Officer
Exelon Generation Company, LLC

COMMONWEALTH EDISON COMPANY

/s/ Joseph R. Trpik, Jr.

Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer
Commonwealth Edison Company

PECO ENERGY COMPANY

/s/ Phillip S. Barnett

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
PECO Energy Company

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ David M. Vahos

David M. Vahos
Senior Vice President, Chief Financial Officer and Treasurer
Baltimore Gas and Electric Company

PEPCO HOLDINGS LLC

/s/ Donna J. Kinzel

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer
Pepco Holdings LLC

POTOMAC ELECTRIC POWER COMPANY

/s/ Donna J. Kinzel

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer
Potomac Electric Power Company

DELMARVA POWER & LIGHT COMPANY

/s/ Donna J. Kinzel

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer
Delmarva Power & Light Company

ATLANTIC CITY ELECTRIC COMPANY

/s/ Donna J. Kinzel

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer
Atlantic City Electric Company

November 2, 2017

EXHIBIT INDEX

Exhibit No.	Description
99.1	Press release and earnings release attachments
99.2	Earnings conference call presentation slides

Exhibit 99.1
News Release

Contact: Dan Eggers
Investor Relations
312-394-2345

Paul Adams
Corporate Communications
410-470-4167

EXELON REPORTS THIRD QUARTER 2017 RESULTS

Earnings Release Highlights

- GAAP Net Income of $0.85 per share and Adjusted (non-GAAP) Operating Earnings of $0.85 per share for the third quarter of 2017
- Narrowing guidance range for full year 2017 Adjusted (non-GAAP) Operating Earnings from $2.50 - $2.80 per share to $2.55 - $2.75 per share including the 9 cent impact from delays to the Illinois Zero Emission Credit (ZEC) contract signing from December 2017 to January 2018
- Announcing another $250 million of cost reductions with full run-rate savings to be achieved in 2020
- New Jersey Board of Public Utilities (NJBPU) approval of ACE's $43 million settlement for its electric distribution rate case
- Maryland Public Service Commission (MDPSC) order issued granting Pepco Maryland a $32 million increase for its electric distribution rate case
- Record third-quarter production for Exelon Nuclear and fewer refueling outage days compared with a year ago

CHICAGO (November 2, 2017) — Exelon Corporation (NYSE: EXC) today reported its financial results for the third quarter 2017.

"Exelon delivered a strong third quarter, led by our Utilities that are performing ahead of plan for the year while providing first quartile reliability, customer satisfaction, and safety across most metrics," said Christopher M. Crane, Exelon's president and CEO. "We are encouraged by the U.S. Department of Energy's recent support for proposed market reforms that would help preserve reliable, emissions-free nuclear energy for the benefit of our customers, environment and communities. We see an important first step coming through potential changes in energy price formation which could be implemented in PJM by mid-year 2018. Our company's commitment to advancing clean energy and sustainability remains a strategic priority, as was recognized by our inclusion on the Dow Jones Sustainability Index for the 12th consecutive year."

"In the third quarter of 2017, Exelon delivered solid financial performance with Adjusted (non-GAAP) operating earnings of $0.85 per share, which is at the mid-point of our guidance range," said Jonathan W. Thayer, Exelon's Senior Executive Vice President and CFO. "Exelon is narrowing the full-year 2017 guidance from $2.50 - $2.80 to $2.55 - $2.75 per share as our utilities perform better than planned, absorbing the impact of delays in recognition of Illinois ZEC revenues until 2018. We also continue to execute against a disciplined management plan that is focused on strengthening and optimizing our operations. We are now targeting another $250 million of annual cost savings by 2020, bringing total annual run-rate savings to over $700 million from initiatives identified since 2015."

Third Quarter 2017

Exelon's GAAP Net Income for the third quarter 2017 increased to $0.85 per share from $0.53 per share in the third quarter of 2016; Adjusted (non-GAAP) Operating Earnings decreased to $0.85 per share in the third quarter of 2017 from $0.91 per share in the third quarter of 2016. For the reconciliations of GAAP Net Income to Adjusted (non-GAAP) Operating Earnings, refer to the tables beginning on page 6.

Adjusted (non-GAAP) Operating Earnings in the third quarter of 2017 reflect the impacts of lower load volumes delivered at Generation due to mild weather, lower realized energy prices related to Exelon's ratable hedging strategy and unfavorable weather conditions at the utilities, partially offset by higher utility earnings due to regulatory rate increases, ZEC revenue related to the New York Clean Energy Standard (CES) and increased capacity prices.

Operating Company Results[1]

ComEd

ComEd's third quarter 2017 GAAP Net Income was $189 million compared with $37 million in the third quarter of 2016. ComEd's Adjusted (non-GAAP) Operating Earnings were $186 million for the third quarter 2017 and the third quarter 2016, primarily reflecting higher electric distribution and transmission formula rate earnings, offset by favorable weather conditions in 2016. Pursuant to the Illinois Future Energy Jobs Act, beginning in 2017, customer rates for ComEd are adjusted to eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution volumes.

PECO

PECO's third quarter 2017 GAAP Net Income was $112 million compared with $122 million in the third quarter of 2016. PECO's Adjusted (non-GAAP) Operating Earnings for the third quarter 2017 were $114 million compared with $123 million in the third quarter of 2016, primarily due to unfavorable weather conditions, partially offset by the impacts of higher income tax repairs deduction.

Cooling degree days were down 23.2 percent relative to the same period in 2016 and were 7.2 percent above normal. Total retail electric deliveries were down 8.2 percent compared with the third quarter of 2016. Natural gas deliveries (including both retail and transportation segments) in the third quarter of 2017 were down 10.6 percent compared with the same period in 2016.

[1]Exelon's five business units include ComEd, which consists of electricity transmission and distribution operations in northern Illinois; PECO, which consists of electricity transmission and distribution operations and retail natural gas distribution operations in southeastern Pennsylvania, BGE, which consists of electricity transmission and distribution operations and retail natural gas distribution operations in central Maryland; PHI, which consists of electricity transmission and distribution operations in the District of Columbia and portions of Maryland, Delaware, and New Jersey and retail natural gas distribution operations in northern Delaware; and Generation, which consists of owned and contracted electric generating facilities and wholesale and retail customer supply of electric and natural gas products and services, including renewable energy products and risk management services.

BGE

BGE's third quarter 2017 GAAP Net Income was $62 million compared with $54 million in the third quarter of 2016. BGE's Adjusted (non-GAAP) Operating Earnings for the third quarter 2017 were $64 million compared with $55 million in the third quarter of 2016, primarily due to regulatory rate increases. Due to revenue decoupling, BGE is not affected by actual weather or customer usage patterns.

PHI

PHI's third quarter 2017 GAAP Net Income was $153 million compared with $166 million in the third quarter of 2016. PHI's Adjusted (non-GAAP) Operating Earnings for the third quarter 2017 were $146 million compared with $130 million in the third quarter of 2016, primarily due to regulatory rate increases in 2016 and 2017. Due to revenue decoupling, PHI's revenues related to Pepco and DPL Maryland are not affected by actual weather or customer usage patterns.

Generation

Generation's third quarter 2017 GAAP Net Income was $305 million compared with $236 million in the third quarter of 2016. Generation's Adjusted (non-GAAP) Operating Earnings for the third quarter 2017 were $347 million compared with $376 million in the third quarter of 2016, primarily reflecting the impacts of lower load volumes delivered due to mild weather and lower realized energy prices related to Exelon's ratable hedging strategy, partially offset by ZEC revenue related to the New York CES and increased capacity prices.

The proportion of expected generation hedged as of September 30, 2017 was 98.0 percent to 101.0 percent for 2017, 79.0 percent to 82.0 percent for 2018 and 45.0 percent to 48.0 percent for 2019.

Third Quarter and Recent Highlights

- **ACE New Jersey Electric Distribution Rate Case:** On September 22, 2017, the NJBPU approved ACE's filed settlement for its pending electric distribution rate case, which provides for an increase in ACE annual electric distribution base rates of $43 million (before New Jersey sales and use tax) reflecting a ROE of 9.6 percent. Pursuant to the settlement agreement, ACE agreed to withdraw its request for approval of a System Renewal Recovery Charge without prejudice to its right to refile. The new rates were effective on October 1, 2017.

- **Pepco Maryland Electric Distribution Rate Case:** On October 20, 2017, the MDPSC approved an increase in Pepco electric distribution rates of $34 million, reflecting a ROE of 9.5 percent. On October 27, 2017, the MDPSC issued an errata order revising the approved increase in Pepco electric distribution rates to $32 million. The errata order corrected a number of computational errors in the original order but did not alter any of the findings. The new rates became effective for services rendered on or after October 20, 2017. In its decision, the MDPSC denied Pepco's request regarding the income tax adjustment without prejudice to Pepco filing another similar proposal with additional information. Requests for rehearing are due November 20, 2017.

- **DPL Delaware Electric and Natural Gas Distribution Rates Case:** On August 17, 2017, DPL filed applications with the Delaware Public Service Commission (DPSC) to increase its annual electric and natural gas distribution base rates by $24 million, which was updated to $31 million on October 18, 2017, and $13 million, respectively, reflecting a requested ROE of 10.1 percent. DPL expects a decision in the electric proceeding and the gas proceeding in the third quarter of 2018, but cannot predict how much of the requested rate increases the DPSC will approve. While the DPSC is not required to issue a decision on the application within a specified period of time, Delaware law allows DPL to put into effect $2.5 million of the rate increase two months after filing the application and the entire requested rate increase seven months after filing, subject to a cap and a refund obligation based on the final DPSC order. On October 24, 2017, the Staff of the DPSC and the Public Advocate filed a joint motion to dismiss DPL's electric distribution base rate application without prejudice to refiling, arguing that the amount of the requested increase to $31 million required additional time to review and additional public notice. The DPSC is expected to decide at its meeting on November 9, 2017. DPL cannot predict the outcome of this matter.

- **Updated Cost Management Program:** In November 2017, Exelon announced the elimination of approximately $250 million of annual ongoing costs, primarily at Generation, by 2020. This announcement is a result of Exelon's continuous focus on improving its cost profile through enhanced efficiency and productivity. These cost reductions result in a cost profile that better aligns with current market conditions. The targeted cost savings are incremental to the expected savings from previous cost management initiatives.

- **DOE Notice of Proposed Rulemaking:** On August 23, 2017, the United States Department of Energy (DOE) released its report on the reliability of the electric grid. One aspect of the wide-ranging report is the DOE's recognition that the electricity markets do not currently value the resiliency provided by baseload generation, such as nuclear plants. On September, 28, 2017, the DOE issued a Notice of Proposed Rulemaking (NOPR) that would entitle certain eligible resilient generating units (i.e., those located in organized markets, with a 90-day supply of fuel on site, not already subject to state cost of service regulation and satisfying certain other requirements) to recover fully allocated costs and earn a fair return on equity on their investment. On October 2, 2017, the Federal Energy Regulatory Commission (FERC) issued a notice inviting comments regarding the DOE NOPR within 21 days and established a new docket wherein the FERC will consider the matter. On October 23, 2017, Exelon filed comments with the FERC, supporting the goals of the NOPR and urging the agency to take swift action to protect customers from power supply interruptions and ensure resiliency in a way that appropriately balances the value and cost to customers. Exelon cannot predict the final outcome of the proceeding or its potential impact, if any, on Exelon or Generation.

- **Delay in Illinois ZEC Revenue Recognition:** On October 27, 2017, the Illinois Power Agency (IPA) released the schedule for the ZEC procurement event indicating that contracts with zero emission facilities will be fully executed on January 30, 2018. It was anticipated that the procurement event and the execution of contracts with winning ZEC suppliers would occur in December 2017 and therefore Exelon would begin to recognize expected Illinois ZEC revenue retroactive to June 1, 2017, in the fourth quarter 2017. Exelon now expects to recognize Illinois ZEC revenue in the first quarter of 2018, effectively shifting $0.09 of EPS from 2017 into 2018. The delayed timing will have no impact on the amount of ZEC revenue.

- **Nuclear Operations:** Generation's nuclear fleet, including its owned output from the Salem Generating Station and 100 percent of the CENG units, produced 47,747 gigawatt-hours (GWhs) in the third quarter of 2017, compared with 44,709 GWhs in the third quarter of 2016. Excluding Salem, the Exelon-operated nuclear plants at ownership achieved a 96.1 percent capacity factor for the third quarter of 2017, compared with 96.3 percent for the third quarter of 2016. The number of planned refueling outage days in the third quarter of 2017 totaled 13, compared with 17 in the third quarter of 2016. There were 15 non-refueling outage days in the third quarter of 2017, compared with 0 days in the third quarter of 2016.

- **Fossil and Renewables Operations:** The dispatch match rate for Generation’s gas and hydro fleet was 98.4 percent in the third quarter of 2017, compared with 97.9 percent in the third quarter of 2016. The reported performance does not include Wolf Hollow II or Colorado Bend II, the two new combined-cycle gas turbine units that went into full commercial operation in the second quarter of 2017. Energy capture for the wind and solar fleet was 95.9 percent in the third quarter of 2017, compared with 95.2 percent in the third quarter of 2016.

- **State of Illinois Income Tax Rate Change:** On July 6, 2017, Illinois enacted Senate Bill 9, which permanently increased Illinois’ total corporate income tax rate from 7.75 percent to 9.50 percent effective July 1, 2017. In addition, in the third quarter of 2017, Exelon updated its marginal state income tax rates based on 2016 state apportionment rates. As a result of these changes, Exelon, Generation and ComEd recorded a one-time increase to Deferred income taxes of approximately $250 million, $20 million and $270 million, respectively, on their Consolidated Balance Sheets in the third quarter of 2017. As income taxes are recovered through rates, each of Exelon and ComEd recorded a corresponding regulatory asset of $272 million. Further, Exelon recorded a decrease of approximately $20 million and Generation recorded an increase of approximately $20 million (each net of federal taxes) to Income tax expense in the third quarter of 2017. The income tax rate increase is not expected to have a material ongoing impact to Exelon’s, Generation’s or ComEd’s future results of operations.

- **Financing Activities:**
  - On August 23, 2017, ComEd issued $350 million aggregate principal amount of its First Mortgage 2.950 percent Bonds, due August 15, 2027 and $650 million aggregate principal amount of its First Mortgage 3.750 percent Bonds, due August 15, 2047. ComEd used the proceeds from the Bonds to refinance maturing First Mortgage Bonds, to repay a portion of ComEd’s outstanding commercial paper obligations and for general corporate purposes.
  - On August 24, 2017, BGE issued $300 million aggregate principal amount of its 3.750 percent Notes due 2047. BGE used the proceeds from the Notes to redeem $250 million in principal amount of the 6.200 percent Deferrable Interest Subordinated Debentures due October 15, 2043 issued by BGE's affiliate BGE Capital Trust II, to repay commercial paper obligations and for general corporate purposes.
  - On September 18, 2017, PECO issued $325 million aggregate principal amount of its First and Refunding Mortgage Bonds, 3.700 percent Series due September 15, 2047. PECO used the proceeds from the Bonds for general corporate purposes.

GAAP/Adjusted (non-GAAP) Operating Earnings Reconciliation

Adjusted (non-GAAP) Operating Earnings for the third quarter of 2017 do not include the following items (after tax) that were included in reported GAAP Net Income:

(in millions)	Exelon Earnings per Diluted Share	Exelon	ComEd	PECO	BGE	PHI	Generation
2017 GAAP Net Income	**$ 0.85**	**$ 824**	**$ 189**	**$ 112**	**$ 62**	**$ 153**	**$ 305**
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $29)	(0.05)	(45)	—	—	—	—	(46)
Unrealized Gains Related to Nuclear Decommissioning Trust (NDT) Fund Investments (net of taxes of $45)	(0.07)	(67)	—	—	—	—	(67)
Amortization of Commodity Contract Intangibles (net of taxes of $8)	0.01	12	—	—	—	—	12
Merger and Integration Costs (net of taxes of $1, $6 and $5, respectively)	—	(1)	—	—	—	(9)	7
Long-Lived Asset Impairments (net of taxes of $16)	0.03	24	—	—	—	—	25
Plant Retirements and Divestitures (net of taxes of $47 and $46, respectively)	0.08	71	—	—	—	—	72
Cost Management Program (net of taxes of $8, $1, $1 and $6 respectively)	0.01	13	—	2	2	—	10
Reassessment of State Deferred Income Taxes (entire amount represents tax expense)	(0.02)	(21)	(3)	—	—	2	18
Bargain Purchase Gain (net of taxes of $0)	(0.01)	(7)	—	—	—	—	(7)
Asset Retirement Obligation (net of taxes of $1)	—	(2)	—	—	—	—	(2)
Noncontrolling Interests (net of taxes of $4)	0.02	20	—	—	—	—	20
2017 Adjusted (non-GAAP) Operating Earnings	**$ 0.85**	**$ 821**	**$ 186**	**$ 114**	**$ 64**	**$ 146**	**$ 347**

Adjusted (non-GAAP) Operating Earnings for the third quarter of 2016 do not include the following items (after tax) that were included in reported GAAP Net Income:

(in millions)	Exelon Earnings per Diluted Share	Exelon	ComEd	PECO	BGE	PHI	Generation
2016 GAAP Net Income	**$ 0.53**	**$ 490**	**$ 37**	**$ 122**	**$ 54**	**$ 166**	**$ 236**
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $35)	(0.06)	(54)	—	—	—	—	(54)
Unrealized Gains Related to NDT Fund Investments (net of taxes of $48)	(0.07)	(70)	—	—	—	—	(70)
Amortization of Commodity Contract Intangibles (net of taxes of $8)	0.01	13	—	—	—	—	13
Merger and Integrations Costs (net of taxes of $10, $1, $1, $3 and $5, respectively)	0.01	13	—	1	1	4	7
Merger Commitments (net of taxes of $1 and $10, respectively)	0.01	5	—	—	—	(40)	—
Long-Lived Asset Impairments (net of taxes of $5 and $6, respectively)	0.01	11	—	—	—	—	10
Plant Retirements and Divestitures (net of taxes of $129)	0.22	204	—	—	—	—	204
Cost Management Program (net of taxes of $5)	0.01	7	—	—	—	—	7
Like-Kind Exchange Tax Position (net of taxes of $61 and $42, respectively)	0.21	199	149	—	—	—	—
Noncontrolling Interests (net of taxes of $5)	0.03	23	—	—	—	—	23
2016 Adjusted (non-GAAP) Operating Earnings	**$ 0.91**	**$ 841**	**$ 186**	**$ 123**	**$ 55**	**$ 130**	**$ 376**

Note:
Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net Income and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates for each Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. For all items except the unrealized gains and losses related to NDT fund investments, the marginal statutory income tax rates ranged from 39.0 percent to 41.0 percent. Under IRS regulations, NDT fund investment returns are taxed at differing rates for investments in qualified vs. non-qualified funds. The tax rates applied to unrealized gains and losses related to NDT fund investments were 43.2 percent and 52.6 percent for the three months ended September 30, 2017 and 2016, respectively.

Webcast Information

Exelon will discuss third quarter 2017 earnings in a one-hour conference call scheduled for today at 9 a.m. Central Time (10 a.m. Eastern Time). The webcast and associated materials can be accessed at www.exeloncorp.com/investor-relations.

About Exelon

Exelon Corporation (NYSE: EXC) is a Fortune 100 energy company with the largest number of utility customers in the U.S. Exelon does business in 48 states, the District of Columbia and Canada and had 2016 revenue of $31.4 billion. Exelon's six utilities deliver electricity and natural gas to approximately 10 million customers in Delaware, the District of Columbia, Illinois, Maryland, New Jersey and Pennsylvania through its Atlantic City Electric, BGE, ComEd, Delmarva Power, PECO and Pepco subsidiaries. Exelon is one of the largest competitive U.S. power generators, with more than 35,500 megawatts of nuclear, gas, wind, solar and hydroelectric generating capacity comprising one of the nation's cleanest and lowest-cost power generation fleets. The company's Constellation business unit provides energy products and services to approximately 2.2 million residential, public sector and business customers, including more than two-thirds of the Fortune 100. Follow Exelon on Twitter @Exelon.

Non-GAAP Financial Measures

In addition to net income as determined under generally accepted accounting principles in the United States (GAAP), Exelon evaluates its operating performance using the measure of Adjusted (non-GAAP) Operating Earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) Operating Earnings exclude certain costs, expenses, gains and losses and other specified items. This measure is intended to enhance an investor's overall understanding of period over period operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this measure is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) Operating Earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentation. The Company has provided the non-GAAP financial measure as supplemental information and in addition to the financial measures that are calculated and presented in accordance with GAAP. Adjusted (non-GAAP) Operating Earnings should not be deemed more useful than, a substitute for, or an alternative to the most comparable GAAP Net Income measures provided in this earnings release and attachments. This press release and earnings release attachments provide reconciliations of adjusted (non-GAAP) Operating Earnings to the most directly comparable financial measures calculated and presented in accordance with GAAP, are posted on Exelon's website: www.exeloncorp.com, and have been furnished to the Securities and Exchange Commission on Form 8-K on November 2, 2017.

Cautionary Statements Regarding Forward-Looking Information

This press release contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants) include those factors discussed herein, as well as the items discussed in (1) the Registrants' 2016 Annual Report on 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 24, Commitments and Contingencies; (2) the Registrants' Third Quarter 2017 Quarterly Report on Form 10-Q (to be filed on November 2, 2017) in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18, Commitments and Contingencies; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this press release. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this press release.

Earnings Release Attachments
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EXELON CORPORATION
Consolidating Statements of Operations
(unaudited)
(in millions)

	Three Months Ended September 30, 2017						
	Generation	ComEd	PECO	BGE	PHI (a)	Other (b)	Exelon Consolidated
Operating revenues	$ 4,751	$ 1,571	$ 715	$ 738	$ 1,310	$ (316)	$ 8,769
Operating expenses							
Purchased power and fuel	2,331	529	235	269	473	(295)	3,542
Operating and maintenance	1,374	346	197	175	251	(43)	2,300
Depreciation and amortization	410	212	72	109	179	20	1,002
Taxes other than income	141	80	42	61	122	10	456
Total operating expenses	4,256	1,167	546	614	1,025	(308)	7,300
(Loss) gain on sales of assets	(2)	—	—	—	—	1	(1)
Bargain purchase gain	7	—	—	—	—	—	7
Operating income (loss)	500	404	169	124	285	(7)	1,475
Other income and (deductions)							
Interest expense, net	(113)	(89)	(31)	(26)	(62)	(65)	(386)
Other, net	209	5	2	4	13	4	237
Total other income and (deductions)	96	(84)	(29)	(22)	(49)	(61)	(149)
Income (loss) before income taxes	596	320	140	102	236	(68)	1,326
Income taxes	240	131	28	40	83	(70)	452
Equity in (losses) earnings of unconsolidated affiliates	(8)	—	—	—	—	1	(7)
Net income	348	189	112	62	153	3	867
Net income attributable to noncontrolling interests	43	—	—	—	—	—	43
Net income attributable to common shareholders	$ 305	$ 189	$ 112	$ 62	$ 153	$ 3	$ 824

	Three Months Ended September 30, 2016						
	Generation	ComEd	PECO	BGE	PHI (a)	Other (a)	Exelon Consolidated
Operating revenues	$ 5,035	$ 1,497	$ 788	$ 812	$ 1,394	$ (524)	$ 9,002
Operating expenses							
Purchased power and fuel	2,589	454	272	360	583	(504)	3,754
Operating and maintenance	1,336	377	199	178	226	22	2,338
Depreciation and amortization	632	196	67	101	182	17	1,195
Taxes other than income	136	82	46	58	124	3	449
Total operating expenses	4,693	1,109	584	697	1,115	(462)	7,736
Gain on sales of assets	—	1	—	—	—	—	1
Operating income (loss)	342	389	204	115	279	(62)	1,267
Other income and (deductions)							
Interest expense, net	(77)	(197)	(30)	(28)	(64)	(120)	(516)
Other, net	185	(80)	2	5	19	(11)	120
Total other income and (deductions)	108	(277)	(28)	(23)	(45)	(131)	(396)
Income (loss) before income taxes	450	112	176	92	234	(193)	871
Income taxes	173	75	54	36	68	(66)	340
Equity in losses of unconsolidated affiliates	(6)	—	—	—	—	1	(5)
Net income (loss)	271	37	122	56	166	(126)	526
Net income (loss) attributable to noncontrolling interests and preference stock dividends	35	—	—	2	—	(1)	36
Net income (loss) attributable to common shareholders	$ 236	$ 37	$ 122	$ 54	$ 166	$ (125)	$ 490

(a) PHI includes the consolidated results of Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company.
(b) Other primarily includes eliminating and consolidating adjustments, Exelon's corporate operations, shared service entities and other financing and investment activities.

EXELON CORPORATION
Consolidating Statements of Operations
(unaudited)
(in millions)

	Nine Months Ended September 30, 2017						
	Generation	ComEd	PECO	BGE	PHI	Other (a)	Exelon Consolidated
Operating revenues	$ 13,812	$ 4,227	$ 2,141	$ 2,363	$ 3,557	$ (951)	$ 25,149
Operating expenses							
Purchased power and fuel	7,286	1,241	719	853	1,318	(890)	10,527
Operating and maintenance	4,871	1,096	595	532	774	(136)	7,732
Depreciation and amortization	1,046	631	213	348	511	65	2,814
Taxes other than income	425	223	116	180	344	25	1,313
Total operating expenses	13,628	3,191	1,643	1,913	2,947	(936)	22,386
Gain on sales of assets	3	—	—	—	1	—	4
Bargain purchase gain	233	—	—	—	—	—	233
Operating income (loss)	420	1,036	498	450	611	(15)	3,000
Other income and (deductions)							
Interest expense, net	(342)	(275)	(93)	(80)	(183)	(221)	(1,194)
Other, net	648	14	6	12	40	5	725
Total other income and (deductions)	306	(261)	(87)	(68)	(143)	(216)	(469)
Income (loss) before income taxes	726	775	411	382	468	(231)	2,531
Income taxes	209	328	84	151	109	(286)	595
Equity in (losses) earnings of unconsolidated affiliates	(26)	—	—	—	—	1	(25)
Net income	491	447	327	231	359	56	1,911
Net income attributable to noncontrolling interests	12	—	—	—	—	—	12
Net income attributable to common shareholders	$ 479	$ 447	$ 327	$ 231	$ 359	$ 56	$ 1,899

	Nine Months Ended September 30, 2016						
	Generation	ComEd	PECO	BGE	PHI (b)	Other (a)	Exelon Consolidated
Operating revenues	$ 13,363	$ 4,031	$ 2,293	$ 2,421	$ 2,565	$ (1,187)	$ 23,486
Operating expenses							
Purchased power and fuel	6,609	1,141	809	994	1,037	(1,128)	9,462
Operating and maintenance	4,333	1,113	604	588	921	118	7,677
Depreciation and amortization	1,329	574	201	307	355	55	2,821
Taxes other than income	380	222	126	172	248	20	1,168
Total operating expenses	12,651	3,050	1,740	2,061	2,561	(935)	21,128
Gain on sales of assets	31	6	—	—	—	4	41
Operating income (loss)	743	987	553	360	4	(248)	2,399
Other income and (deductions)							
Interest expense, net	(273)	(374)	(92)	(76)	(135)	(229)	(1,179)
Other, net	395	(72)	6	16	31	1	377
Total other income and (deductions)	122	(446)	(86)	(60)	(104)	(228)	(802)
Income (loss) before income taxes	865	541	467	300	(100)	(476)	1,597
Income taxes	293	244	121	109	(9)	(133)	625
Equity in losses of unconsolidated affiliates	(16)	—	—	—	—	—	(16)
Net income (loss)	556	297	346	191	(91)	(343)	956
Net income attributable to noncontrolling interests and preference stock dividends	18	—	—	8	—	—	26
Net income (loss) attributable to common shareholders	$ 538	$ 297	$ 346	$ 183	$ (91)	$ (343)	$ 930

(a) Other primarily includes eliminating and consolidating adjustments, Exelon's corporate operations, shared service entities and other financing and investment activities.
(b) PHI includes the consolidated results of Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company beginning on March 24, 2016, the day after the merger was completed.

EXELON CORPORATION
Business Segment Comparative Statements of Operations
(unaudited)
(in millions)

Generation

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	**2016**	**Variance**	**2017**	**2016**	**Variance**
Operating revenues	$ 4,751	$ 5,035	$ (284)	$ 13,812	$ 13,363	$ 449
Operating expenses						
Purchased power and fuel	2,331	2,589	(258)	7,286	6,609	677
Operating and maintenance	1,374	1,336	38	4,871	4,333	538
Depreciation and amortization	410	632	(222)	1,046	1,329	(283)
Taxes other than income	141	136	5	425	380	45
Total operating expenses	4,256	4,693	(437)	13,628	12,651	977
Gain on sales of assets	(2)	—	(2)	3	31	(28)
Bargain purchase gain	7	—	7	233	—	233
Operating income	500	342	158	420	743	(323)
Other income and (deductions)						
Interest expense, net	(113)	(77)	(36)	(342)	(273)	(69)
Other, net	209	185	24	648	395	253
Total other income and (deductions)	96	108	(12)	306	122	184
Income before income taxes	596	450	146	726	865	(139)
Income taxes	240	173	67	209	293	(84)
Equity in losses of unconsolidated affiliates	(8)	(6)	(2)	(26)	(16)	(10)
Net income	348	271	77	491	556	(65)
Net income attributable to noncontrolling interests	43	35	8	12	18	(6)
Net income attributable to membership interest	$ 305	$ 236	$ 69	$ 479	$ 538	$ (59)

ComEd

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	**2016**	**Variance**	**2017**	**2016**	**Variance**
Operating revenues	$ 1,571	$ 1,497	$ 74	$ 4,227	$ 4,031	$ 196
Operating expenses						
Purchased power	529	454	75	1,241	1,141	100
Operating and maintenance	346	377	(31)	1,096	1,113	(17)
Depreciation and amortization	212	196	16	631	574	57
Taxes other than income	80	82	(2)	223	222	1
Total operating expenses	1,167	1,109	58	3,191	3,050	141
Gain on sales of assets	—	1	(1)	—	6	(6)
Operating income	404	389	15	1,036	987	49
Other income and (deductions)						
Interest expense, net	(89)	(197)	108	(275)	(374)	99
Other, net	5	(80)	85	14	(72)	86
Total other income and (deductions)	(84)	(277)	193	(261)	(446)	185
Income before income taxes	320	112	208	775	541	234
Income taxes	131	75	56	328	244	84
Net income	$ 189	$ 37	$ 152	$ 447	$ 297	$ 150

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EXELON CORPORATION
Business Segment Comparative Statements of Operations
(unaudited)
(in millions)

PECO

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Variance	2017	2016	Variance
Operating revenues	$ 715	$ 788	$ (73)	$ 2,141	$ 2,293	$ (152)
Operating expenses						
Purchased power and fuel	235	272	(37)	719	809	(90)
Operating and maintenance	197	199	(2)	595	604	(9)
Depreciation and amortization	72	67	5	213	201	12
Taxes other than income	42	46	(4)	116	126	(10)
Total operating expenses	546	584	(38)	1,643	1,740	(97)
Operating income	169	204	(35)	498	553	(55)
Other income and (deductions)						
Interest expense, net	(31)	(30)	(1)	(93)	(92)	(1)
Other, net	2	2	—	6	6	—
Total other income and (deductions)	(29)	(28)	(1)	(87)	(86)	(1)
Income before income taxes	140	176	(36)	411	467	(56)
Income taxes	28	54	(26)	84	121	(37)
Net income	$ 112	$ 122	$ (10)	$ 327	$ 346	$ (19)

BGE

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Variance	2017	2016	Variance
Operating revenues	$ 738	$ 812	$ (74)	$ 2,363	$ 2,421	$ (58)
Operating expenses						
Purchased power and fuel	269	360	(91)	853	994	(141)
Operating and maintenance	175	178	(3)	532	588	(56)
Depreciation and amortization	109	101	8	348	307	41
Taxes other than income	61	58	3	180	172	8
Total operating expenses	614	697	(83)	1,913	2,061	(148)
Operating income	124	115	9	450	360	90
Other income and (deductions)						
Interest expense, net	(26)	(28)	2	(80)	(76)	(4)
Other, net	4	5	(1)	12	16	(4)
Total other income and (deductions)	(22)	(23)	1	(68)	(60)	(8)
Income before income taxes	102	92	10	382	300	82
Income taxes	40	36	4	151	109	42
Net income	62	56	6	231	191	40
Preference stock dividends	—	2	(2)	—	8	(8)
Net income attributable to common shareholder	$ 62	$ 54	$ 8	$ 231	$ 183	$ 48

EXELON CORPORATION
Business Segment Comparative Statements of Operations
(unaudited)
(in millions)

PHI

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	**2016**	**Variance**	**2017**	**2016 (a)**	**Variance**
Operating revenues	$ 1,310	$ 1,394	$ (84)	$ 3,557	$ 2,565	$ 992
Operating expenses						
Purchased power and fuel	473	583	(110)	1,318	1,037	281
Operating and maintenance	251	226	25	774	921	(147)
Depreciation and amortization	179	182	(3)	511	355	156
Taxes other than income	122	124	(2)	344	248	96
Total operating expenses	1,025	1,115	(90)	2,947	2,561	386
Gain on sales of assets	—	—	—	1	—	1
Operating income	285	279	6	611	4	607
Other income and (deductions)						
Interest expense, net	(62)	(64)	2	(183)	(135)	(48)
Other, net	13	19	(6)	40	31	9
Total other income and (deductions)	(49)	(45)	(4)	(143)	(104)	(39)
Income (loss) before income taxes	236	234	2	468	(100)	568
Income taxes	83	68	15	109	(9)	118
Net income (loss)	$ 153	$ 166	$ (13)	$ 359	$ (91)	$ 450

Other (b)

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	**2016**	**Variance**	**2017**	**2016**	**Variance**
Operating revenues	$ (316)	$ (524)	$ 208	$ (951)	$ (1,187)	$ 236
Operating expenses						
Purchased power and fuel	(295)	(504)	209	(890)	(1,128)	238
Operating and maintenance	(43)	22	(65)	(136)	118	(254)
Depreciation and amortization	20	17	3	65	55	10
Taxes other than income	10	3	7	25	20	5
Total operating expenses	(308)	(462)	154	(936)	(935)	(1)
Gain on sales of assets	1	—	1	—	4	(4)
Operating loss	(7)	(62)	55	(15)	(248)	233
Other income and (deductions)						
Interest expense, net	(65)	(120)	55	(221)	(229)	8
Other, net	4	(11)	15	5	1	4
Total other income and (deductions)	(61)	(131)	70	(216)	(228)	12
Loss before income taxes	(68)	(193)	125	(231)	(476)	245
Income taxes	(70)	(66)	(4)	(286)	(133)	(153)
Equity in earnings of unconsolidated affiliates	1	1	—	1	—	1
Net income (loss)	3	(126)	129	$ 56	$ (343)	$ 399
Net loss attributable to noncontrolling interests and preference stock dividends	—	(1)	1	—	—	—
Net income (loss) attributable to common shareholders	$ 3	$ (125)	$ 128	$ 56	$ (343)	$ 399

(a) PHI includes the consolidated results of Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company beginning on March 24, 2016, the day after the merger was completed.
(b) Other primarily includes eliminating and consolidating adjustments, Exelon's corporate operations, shared service entities and other financing and investment activities.

EXELON CORPORATION
Consolidated Balance Sheets
(unaudited) (in millions)

	September 30, 2017	December 31, 2016
Assets		
Current assets		
Cash and cash equivalents	$ 1,203	$ 635
Restricted cash and cash equivalents	320	253
Deposit with IRS	1,250	1,250
Accounts receivable, net		
Customer	3,854	4,158
Other	950	1,201
Mark-to-market derivative assets	699	917
Unamortized energy contract assets	81	88
Inventories, net		
Fossil fuel and emission allowances	387	364
Materials and supplies	1,281	1,274
Regulatory assets	1,264	1,342
Other	1,435	930
Total current assets	12,724	12,412
Property, plant and equipment, net	73,067	71,555
Deferred debits and other assets		
Regulatory assets	10,238	10,046
Nuclear decommissioning trust funds	12,966	11,061
Investments	634	629
Goodwill	6,677	6,677
Mark-to-market derivative assets	426	492
Unamortized energy contract assets	407	447
Pledged assets for Zion Station decommissioning	57	113
Other	1,277	1,472
Total deferred debits and other assets	32,682	30,937
Total assets	$ 118,473	$ 114,904
Liabilities and shareholders' equity		
Current liabilities		
Short-term borrowings	$ 710	$ 1,267
Long-term debt due within one year	3,164	2,430
Accounts payable	3,132	3,441
Accrued expenses	3,080	3,460
Payables to affiliates	5	8
Regulatory liabilities	553	602
Mark-to-market derivative liabilities	178	282
Unamortized energy contract liabilities	283	407
Renewable energy credit obligation	261	428
PHI merger related obligation	96	151
Other	933	981
Total current liabilities	12,395	13,457
Long-term debt	31,701	31,575
Long-term debt to financing trusts	389	641
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	19,250	18,138
Asset retirement obligations	9,733	9,111
Pension obligations	4,055	4,248
Non-pension postretirement benefit obligations	1,977	1,848
Spent nuclear fuel obligation	1,142	1,024
Regulatory liabilities	4,549	4,187
Mark-to-market derivative liabilities	410	392
Unamortized energy contract liabilities	656	830
Payable for Zion Station decommissioning	—	14
Other	1,899	1,827
Total deferred credits and other liabilities	43,671	41,619
Total liabilities	88,156	87,292
Commitments and contingencies		
Shareholders' equity		
Common stock	18,862	18,794
Treasury stock, at cost	(123)	(2,327)
Retained earnings	11,950	12,030
Accumulated other comprehensive loss, net	(2,589)	(2,660)

Total shareholders' equity	28,100	25,837
Noncontrolling interests	2,217	1,775
Total equity	30,317	27,612
Total liabilities and shareholders' equity	$ 118,473	$ 114,904

EXELON CORPORATION
Consolidated Statements of Cash Flows
(unaudited)
(in millions)

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Cash flows from operating activities		
Net income	$ 1,911	$ 956
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	3,999	4,009
Impairment of long-lived assets and losses on regulatory assets	488	274
Gain on sales of assets	(5)	(41)
Bargain purchase gain	(233)	—
Deferred income taxes and amortization of investment tax credits	439	623
Net fair value changes related to derivatives	149	100
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(429)	(243)
Other non-cash operating activities	603	1,224
Changes in assets and liabilities:		
Accounts receivable	224	(296)
Inventories	(87)	21
Accounts payable and accrued expenses	(593)	296
Option premiums received (paid), net	35	(24)
Collateral (posted) received, net	(100)	757
Income taxes	167	527
Pension and non-pension postretirement benefit contributions	(344)	(283)
Other assets and liabilities	(547)	(537)
Net cash flows provided by operating activities	5,677	7,363
Cash flows from investing activities		
Capital expenditures	(5,556)	(6,368)
Proceeds from nuclear decommissioning trust fund sales	6,848	7,914
Investment in nuclear decommissioning trust funds	(7,044)	(8,093)
Acquisition of businesses, net	(208)	(6,896)
Proceeds from sales of long-lived assets	219	49
Proceeds from termination of direct financing lease investment	—	360
Change in restricted cash	(67)	(75)
Other investing activities	(2)	(110)
Net cash flows used in investing activities	(5,810)	(13,219)
Cash flows from financing activities		
Changes in short-term borrowings	(570)	(1,014)
Proceeds from short-term borrowings with maturities greater than 90 days	621	195
Repayments on short-term borrowings with maturities greater than 90 days	(610)	(452)
Issuance of long-term debt	2,616	4,488
Retirement of long-term debt	(1,728)	(944)
Retirement of long-term debt to financing trust	(250)	—
Restricted proceeds from issuance of long-term debt	—	(30)
Redemption of preference stock	—	(190)
Sale of noncontrolling interest	396	—
Dividends paid on common stock	(921)	(873)
Common stock issued from treasury stock	1,150	—
Proceeds from employee stock plans	61	36
Other financing activities	(64)	35
Net cash flows provided by financing activities	701	1,251
Increase (Decrease) in cash and cash equivalents	568	(4,605)
Cash and cash equivalents at beginning of period	635	6,502
Cash and cash equivalents at end of period	$ 1,203	$ 1,897

EXELON CORPORATION
GAAP Consolidated Statements of Operations and
Adjusted (non-GAAP) Operating Earnings Reconciling Adjustments
(unaudited)
(in millions, except per share data)

	Three Months Ended September 30, 2017			Three Months Ended September 30, 2016		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 8,769	$ (39)	(b),(d)	$ 9,002	$ (166)	(b),(d)
Operating expenses						
Purchased power and fuel	3,542	9	(b),(d),(h)	3,754	(127)	(b),(d),(h)
Operating and maintenance	2,300	(60)	(e),(g),(h),(i),(m)	2,338	(23)	(e),(f),(g),(h),(i)
Depreciation and amortization	1,002	(106)	(h)	1,195	(338)	(e),(h)
Taxes other than income	456	—		449	—	
Total operating expenses	7,300			7,736		
Gain on sales of assets	(1)	2	(h)	1	—	
Bargain purchase gain	7	(7)	(l)	—	—	
Operating income	1,475			1,267		
Other income and (deductions)						
Interest expense, net	(386)	—		(516)	153	(j)
Other, net	237	(118)	(c)	120	(39)	(c),(j)
Total other income and (deductions)	(149)			(396)		
Income before income taxes	1,326			871		
Income taxes	452	18	(b),(c),(d),(e),(g),(h),(i),(k),(m)	340	108	(b),(c),(d)(e),(f),(g),(h),(i),(j)
Equity in losses of unconsolidated affiliates	(7)	—		(5)	—	
Net income	867			526		
Net income attributable to noncontrolling interests and preference stock dividends	43	(20)	(n)	36	(23)	(n)
Net income attributable to common shareholders	$ 824			$ 490		
Effective tax rate(o)	34.1%			39.0%		
Earnings per average common share						
Basic	$ 0.86			$ 0.53		
Diluted	$ 0.85			$ 0.53		
Average common shares outstanding						
Basic	962			925		
Diluted	965			927		
Effect of adjustments on earnings per average diluted common share recorded in accordance with GAAP:						
Mark-to-market impact of economic hedging activities (b)		$ (0.05)			$ (0.06)	
Unrealized gains related to NDT fund investments (c)		(0.07)			(0.07)	
Amortization of commodity contract intangibles (d)		0.01			0.01	
Merger and integration costs (e)		—			0.01	
Merger commitments (f)		—			0.01	
Long-lived asset impairments (g)		0.03			0.01	
Plant retirements and divestitures (h)		0.08			0.22	
Cost management program (i)		0.01			0.01	
Like-kind exchange tax position (j)		—			0.21	
Reassessment of state deferred income taxes (k)		(0.02)			—	
Bargain purchase gain (l)		(0.01)			—	
Asset retirement obligation (m)		—			—	
Noncontrolling interests (n)		0.02			0.03	
Total adjustments		$ —			$ 0.38	

(a) Results reported in accordance with accounting principles generally accepted in the United States (GAAP).
(b) Adjustment to exclude the mark-to-market impact of Exelon's economic hedging activities, net of intercompany eliminations.
(c) Adjustment to exclude the unrealized gains and losses on NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements.
(d) Adjustment to exclude the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value related to the Integrys and ConEdison Solutions acquisitions in 2016, and in 2017, the ConEdison Solutions and FitzPatrick acquisitions.

(e) Adjustment to exclude certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI acquisition in 2016, and in 2017, the PHI and FitzPatrick acquisitions, offset at PHI by the anticipated recovery of previously incurred PHI acquisition costs.
(f) Adjustment to exclude costs incurred as part of the settlement orders approving the PHI acquisition.
(g) Adjustment to exclude charges to earnings related to the impairment of upstream assets at Generation in 2016, and in 2017, impairments of the ExGen Texas Power, LLC assets held for sale.
(h) Adjustment to exclude accelerated depreciation and amortization expenses associated with Generation's previous decision to early retire the Clinton and Quad Cities nuclear facilities in 2016, and Generation's decision to early retire the Three Mile Island nuclear facility in 2017.
(i) Adjustment to exclude severance and reorganization costs related to a cost management program.
(j) Adjustment to exclude the recognition of a penalty and associated interest expense in the third quarter of 2016, as a result of a tax court decision on Exelon's like-kind exchange tax position.
(k) Adjustment to exclude the non-cash impact of the remeasurement of state deferred income taxes, primarily as a result of a change in the Illinois statutory tax rate and changes in forecasted apportionment.
(l) Adjustment to exclude a measurement period adjustment to the bargain purchase gain for the FitzPatrick acquisition.
(m) Adjustment to exclude a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units.
(n) Adjustment to exclude from Generation's results the noncontrolling interests related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.
(o) The effective tax rate related to Adjusted (non-GAAP) Operating Earnings is 35.6% and 34.3% for the three months ended September 30, 2017 and September 30, 2016, respectively.

EXELON CORPORATION
GAAP Consolidated Statements of Operations and
Adjusted (non-GAAP) Operating Earnings Reconciling Adjustments
(unaudited)
(in millions, except per share data)

	Nine Months Ended September 30, 2017			Nine Months Ended September 30, 2016		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 25,149	$ 77	(b),(d)	$ 23,486	$ 368	(b),(d),(e)
Operating expenses						
Purchased power and fuel	10,527	(133)	(b),(d),(h)	9,462	211	(b),(d),(h)
Operating and maintenance	7,732	(633)	(e),(g),(h),(j),(l)	7,677	(956)	(e),(f),(g),(h),(j)
Depreciation and amortization	2,814	(143)	(d),(h)	2,821	(452)	(e),(h)
Taxes other than income	1,313	—		1,168	(1)	(j)
Total operating expenses	22,386			21,128		
Gain on sales of assets	4	1	(h)	41	—	
Bargain purchase gain	233	(233)	(n)	—	—	
Operating income	3,000			2,399		
Other income and (deductions)						
Interest expense, net	(1,194)	59	(g),(k),(m)	(1,179)	153	(k)
Other, net	725	(393)	(c),(k)	377	(193)	(c),(h),(k)
Total other income and (deductions)	(469)			(802)		
Income before income taxes	2,531			1,597		
Income taxes	595	459	(b),(c),(d),(e),(f),(g),(h),(i),(j),(k),(l),(m)	625	419	(b),(c),(d),(e),(f),(g),(h),(j),(k)
Equity in losses of unconsolidated affiliates	(25)	—		(16)	—	
Net income	1,911			956		
Net loss attributable to noncontrolling interests and preference stock dividends	12	(75)	(o)	26	(41)	(o)
Net income attributable to common shareholders	$ 1,899			$ 930		
Effective tax rate[(p)]	23.5%			39.1%		
Earnings per average common share						
Basic	$ 2.02			$ 1.01		
Diluted	$ 2.01			$ 1.00		
Average common shares outstanding						
Basic	941			924		
Diluted	943			926		
Effect of adjustments on earnings per average diluted common share recorded in accordance with GAAP:						
Mark-to-market impact of economic hedging activities (b)		$ 0.10			$ 0.07	
Unrealized gains related to NDT fund investments (c)		(0.22)			(0.13)	
Amortization of commodity contract intangibles (d)		0.03			0.01	
Merger and integration costs (e)		0.04			0.10	
Merger commitments (f)		(0.15)			0.43	
Long-lived asset impairments (g)		0.31			0.11	
Plant retirements and divestitures (h)		0.15			0.37	
Reassessment of state deferred income taxes (i)		(0.04)			—	
Cost management program (j)		0.03			0.03	
Like-kind exchange tax position (k)		(0.03)			0.21	
Asset retirement obligation (l)		—			—	
Tax settlements (m)		(0.01)			—	
Bargain purchase gain (n)		(0.25)			—	
Noncontrolling interests (o)		0.08			0.04	
Total adjustments		$ 0.04			$ 1.24	

As a result of the PHI acquisition completion on March 23, 2016, the table includes financial results for PHI beginning on March 24, 2016 to September 30, 2017. Therefore, the results of operations from 2017 and 2016 are not comparable for Exelon. The explanations below identify any other significant or unusual items affecting the results of operations.

(a) Results reported in accordance with accounting principles generally accepted in the United States (GAAP).

(b) Adjustment to exclude the mark-to-market impact of Exelon’s economic hedging activities, net of intercompany eliminations.
(c) Adjustment to exclude the unrealized gains on NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements.
(d) Adjustment to exclude the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value related to the Integrys and ConEdison Solutions acquisitions in 2016, and in 2017, the ConEdison Solutions and FitzPatrick acquisitions.
(e) Adjustment to exclude certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI acquisition in 2016, partially offset at ComEd, BGE and PHI by the anticipated recovery of previously incurred PHI acquisition costs, and in 2017, the PHI and FitzPatrick acquisitions, partially offset at PHI by the anticipated recovery of previously incurred PHI acquisition costs.
(f) Adjustment to exclude in 2016 costs incurred as part of the settlement orders approving the PHI acquisition, and in 2017, a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions.
(g) Adjustment to exclude charges to earnings related to the impairment of upstream assets and certain wind projects at Generation in 2016, and in 2017, impairments as a result of the ExGen Texas Power, LLC assets held for sale.
(h) Adjustment to exclude accelerated depreciation and amortization expenses, increases to materials and supplies inventory reserves, charges for severance reserves and construction work in progress impairments associated with Generation's previous decision to early retire the Clinton and Quad Cities nuclear facilities in 2016, and Generation's decision to early retire the Three Mile Island nuclear facility in 2017, partially offset in 2016 by a gain associated with Generation’s sale of the New Boston generating site.
(i) Adjustment to exclude the non-cash impact of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment related to the PHI acquisition in 2016, and in 2017, changes in the Illinois and District of Columbia statutory tax rates and changes in forecasted apportionment.
(j) Adjustment to exclude severance and reorganization costs related to a cost management program.
(k) Adjustment to exclude the recognition of a penalty and associated interest expense in 2016 as a result of a tax court decision on Exelon’s like-kind exchange tax position, and adjustments to income tax, penalties and interest expenses in 2017 as a result of the finalization of the IRS tax computation related to Exelon’s like-kind exchange tax position.
(l) Adjustment to exclude a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units.
(m) Adjustment to exclude benefits related to the favorable settlement in 2017 of certain income tax positions related to PHI's unregulated business interests that were transferred to Generation.
(n) Adjustment to exclude the excess of the fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition.
(o) Adjustment to exclude from Generation’s results the noncontrolling interests related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.
(p) The effective tax rate related to Adjusted (non-GAAP) Operating Earnings is 35.7% and 33.4% for the nine months ended September 30, 2017 and September 30, 2016, respectively.

EXELON CORPORATION
Reconciliation of Adjusted (non-GAAP) Operating Earnings to GAAP Net Income (in millions)

Three Months Ended September 30, 2017 and 2016
(unaudited)

	Exelon Earnings per Diluted Share	Generation	ComEd	PECO	BGE	PHI (a)	Other(b)	Exelon
2016 GAAP Net Income (Loss)	**$ 0.53**	**$ 236**	**$ 37**	**$ 122**	**$ 54**	**$ 166**	**$ (125)**	**$ 490**
2016 Adjusted (non-GAAP) Operating (Earnings) Loss Adjustments:								
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $35)	(0.06)	(54)	—	—	—	—	—	(54)
Unrealized Gains Related to NDT Fund Investments (net of taxes of $48) (1)	(0.07)	(70)	—	—	—	—	—	(70)
Amortization of Commodity Contract Intangibles (net of taxes of $8) (2)	0.01	13	—	—	—	—	—	13
Merger and Integration Costs (net of taxes of $5, $1, $1, $3, and $10, respectively) (3)	0.01	7	—	1	1	4	—	13
Merger Commitments (net of taxes of $10, $11 and $1, respectively) (4)	0.01	—	—	—	—	(40)	45	5
Long-Lived Asset Impairments (net of taxes of $6, $1 and $5) (5)	0.01	10	—	—	—	—	1	11
Plant Retirements and Divestitures (net of taxes of $129) (6)	0.22	204	—	—	—	—	—	204
Cost Management Program (net of taxes of $5) (7)	0.01	7	—	—	—	—	—	7
Like-Kind Exchange Tax Position (net of taxes of $42, $19 and $61, respectively) (8)	0.21	—	149	—	—	—	50	199
Noncontrolling Interests (net of taxes of $5) (9)	0.03	23	—	—	—	—	—	23
2016 Adjusted (non-GAAP) Operating Earnings (Loss)	**0.91**	**376**	**186**	**123**	**55**	**130**	**(29)**	**841**
Year Over Year Effects on Earnings:								
ComEd, PECO, BGE and PHI Margins:								
Weather	(0.06)	—	(20) (c)	(28)	— (c)	(6) (c)	—	(54)
Load	(0.01)	—	(3) (c)	1	— (c)	(4) (c)	—	(6)
Other Energy Delivery (13)	0.07	—	23 (d)	6 (d)	10 (d)	26 (d)	—	65
Generation Energy Margins, Excluding Mark-to-Market:								
Nuclear Volume (14)	0.06	59	—	—	—	—	—	59
Nuclear Fuel Cost (15)	—	(2)	—	—	—	—	—	(2)
Capacity Pricing (16)	0.05	46	—	—	—	—	—	46
Zero Emission Credit Revenue (17)	0.08	73	—	—	—	—	—	73
Market and Portfolio Conditions (18)	(0.21)	(198)	—	—	—	—	—	(198)
Operating and Maintenance Expense:								
Labor, Contracting and Materials	0.01	5	3	(4)	2	1	—	7
Planned Nuclear Refueling Outages (19)	—	4	—	—	—	—	—	4
Pension and Non-Pension Postretirement Benefits (20)	—	(2)	(1)	1	1	1	(1)	(1)
Other Operating and Maintenance (21)	0.04	9	16	5	—	—	6	36
Depreciation and Amortization Expense (22)	(0.02)	(6)	(10)	(3)	(5)	2	(2)	(24)
Interest Expense, Net (23)	(0.02)	(19)	2	(1)	1	1	1	(15)
Income Taxes (24)	(0.01)	(7)	(10)	12	—	(3)	(6)	(14)
Equity in Earnings of Unconsolidated Affiliates	—	(1)	—	—	—	—	—	(1)
Noncontrolling Interests (25)	(0.01)	(7)	—	—	—	—	—	(7)
Other (26)	0.01	17	—	2	—	(2)	(5)	12
Share Differential (27)	(0.04)	—	—	—	—	—	—	—
2017 Adjusted (non-GAAP) Operating Earnings (Loss)	**0.85**	**347**	**186**	**114**	**64**	**146**	**(36)**	**821**
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Adjustments:								
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $29)	0.05	46	—	—	—	—	(1)	45
Unrealized Gains Related to NDT Fund Investments (net of taxes of $45) (1)	0.07	67	—	—	—	—	—	67
Amortization of Commodity Contract Intangibles (net of taxes of $8) (2)	(0.01)	(12)	—	—	—	—	—	(12)
Merger and Integration Costs (net of taxes of $5, $6, $0 and $1, respectively) (3)	—	(7)	—	—	—	9	(1)	1
Long-Lived Asset Impairments (net of taxes of $16, $0 and $16, respectively) (5)	(0.03)	(25)	—	—	—	—	1	(24)
Plant Retirements and Divestitures (net of taxes of $46, $1 and $47, respectively) (6)	(0.08)	(72)	—	—	—	—	1	(71)
Cost Management Program (net of taxes of $6, $1, $1, $0 and $8, respectively) (7)	(0.01)	(10)	—	(2)	(2)	—	1	(13)
Reassessment of State Deferred Income Taxes (entire amount represents tax expense) (10)	0.02	(18)	3	—	—	(2)	38	21
Bargain Purchase Gain (net of taxes of $0) (11)	0.01	7	—	—	—	—	—	7
Asset Retirement Obligation (net of taxes of $1) (12)	—	2	—	—	—	—	—	2
Noncontrolling Interests (net of taxes of $4) (9)	(0.02)	(20)	—	—	—	—	—	(20)
2017 GAAP Net Income	**$ 0.85**	**$ 305**	**$ 189**	**$ 112**	**$ 62**	**$ 153**	**$ 3**	**$ 824**

Note:
Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net Income and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates for each Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. For all items except the unrealized gains and losses related to NDT fund investments, the marginal statutory income tax rates ranged from 39.0 percent to 41.0 percent. Under IRS regulations, NDT fund investment returns are taxed at differing rates for investments in qualified vs. non-qualified funds. The tax rates applied to unrealized gains and losses related to NDT fund investments were 43.2 percent and 52.6 percent for the three months ended September 30, 2017 and 2016, respectively.

(a) PHI consolidated results includes Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company.
(b) Other primarily includes eliminating and consolidating adjustments, Exelon's corporate operations, shared service entities and other financing and investment activities.
(c) As approved by the Maryland PSC and District of Columbia PSC, customer rates for BGE, Pepco and DPL Maryland are adjusted to eliminate the favorable and unfavorable impacts of weather and usage patterns per customer on distribution volumes. Pursuant to the Illinois Future Energy Jobs Act, beginning in 2017, customer rates for ComEd are adjusted to eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution volumes.
(d) For regulatory recovery mechanisms, including ComEd's distribution formula rate, ComEd, BGE and PHI utilities transmission formula rates, and riders across all utilities, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).
(1) Reflects the impact of unrealized gains on NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements.
(2) Represents the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value related to the Integrys and ConEdison Solutions acquisitions in 2016, and in 2017, the ConEdison Solutions and FitzPatrick acquisitions.
(3) Reflects certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI acquisition in 2016, and in 2017, the PHI and FitzPatrick acquisitions, offset at PHI by the anticipated recovery of previously incurred PHI acquisition costs.
(4) Represents costs incurred as part of the settlement orders approving the PHI acquisition.
(5) Primarily reflects charges to earnings related to the impairment of upstream assets at Generation in 2016, and in 2017, impairments of the ExGen Texas Power, LLC assets held for sale.
(6) Primarily reflects accelerated depreciation and amortization expenses associated with Generation's previous decision to early retire the Clinton and Quad Cities nuclear facilities in 2016, and Generation's decision to early retire the Three Mile Island nuclear facility in 2017.
(7) Represents severance and reorganization costs related to a cost management program.
(8) Represents the recognition of a penalty and associated interest expense in the third quarter of 2016, as a result of a tax court decision on Exelon's like-kind exchange tax position.
(9) Represents elimination from Generation's results of the noncontrolling interests related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.
(10) Reflects the non-cash impact of the remeasurement of state deferred income taxes, primarily as a result of a change in the Illinois statutory tax rate and changes in forecasted apportionment.
(11) Represents a measurement period adjustment to the bargain purchase gain for the FitzPatrick acquisition.
(12) Primarily reflects a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units.
(13) For ComEd, primarily reflects increased electric distribution and transmission formula rate revenues (due to increased capital investments and higher electric distribution ROE, which is due to an increase in treasury rates), partially offset by lower revenues resulting from the change to defer and recover over time energy efficiency costs pursuant to the Illinois Future Energy Jobs Act. For BGE and PHI, primarily reflects increased revenue as a result of rate increases.
(14) Primarily reflects the acquisition of the FitzPatrick nuclear facility and a decrease in nuclear outage days.
(15) Primarily reflects increased nuclear output, partially offset by a decrease in fuel prices.
(16) Primarily reflects increased capacity prices in the New England, Midwest and Mid-Atlantic regions.
(17) Reflects the impact of the New York Clean Energy Standard.
(18) Primarily reflects the impacts of lower load volumes delivered due to mild weather and lower realized energy prices related to Exelon's ratable hedging strategy, partially offset by the addition of two combined-cycle gas turbines in Texas.
(19) Primarily reflects a decrease in the number of nuclear outage days in 2017, excluding Salem.
(20) Primarily reflects the unfavorable impact of lower pension and OPEB discount rates, partially offset by the favorable impact of lower health care claims experience.
(21) For ComEd, primarily reflects the change to defer and recover over time energy efficiency costs pursuant to the Illinois Future Energy Jobs Act.
(22) For Generation, reflects increased depreciation for the addition of two combined-cycle gas turbines in Texas, partially offset by the absence of depreciation due to the EGTP assets held for sale. Additionally, primarily reflects increased depreciation from ongoing capital expenditures across all operating companies.
(23) For Generation, primarily reflects the impact of project in-service dates on the capitalization of interest and higher outstanding debt.
(24) For ComEd, reflects the 2017 increase in the Illinois statutory income tax rate. For PECO, primarily reflects an increase in the repairs tax deduction.
(25) Reflects elimination from Generation's results of activity attributable to noncontrolling interests, primarily for CENG and the Renewables Joint Venture.
(26) For Generation, primarily reflects higher realized NDT fund gains.
(27) Reflects the impact on earnings per share due to the increase in Exelon's average diluted common shares outstanding as a result of the June 2017 common stock issuance.

EXELON CORPORATION
Reconciliation of Adjusted (non-GAAP) Operating Earnings to GAAP Net Income (in millions)
Nine Months Ended September 30, 2017 and 2016
(unaudited)

	Exelon Earnings per Diluted Share	Generation	ComEd	PECO	BGE	PHI (a)	Other (b)	Exelon (a)
2016 GAAP Net Income (Loss)	**$ 1.00**	**$ 538**	**$ 297**	**$ 346**	**$ 183**	**$ (91)**	**$ (343)**	**$ 930**
2016 Adjusted (non-GAAP) Operating (Earnings) Loss Adjustments:								
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $46)	0.07	67	—	—	—	—	—	67
Unrealized Gains Related to NDT Fund Investments (net of taxes of $89) (1)	(0.13)	(127)	—	—	—	—	—	(127)
Amortization of Commodity Contract Intangibles (net of taxes of $6) (2)	0.01	8	—	—	—	—	—	8
Merger and Integration Costs (net of taxes of $12, $3, $2, $1, $25, $1 and $36, respectively) (3)	0.10	20	(3)	2	(1)	37	37	92
Merger Commitments (net of taxes of $1, $74, $38 and $114, respectively) (4)	0.43	2	—	—	—	239	159	400
Long-Lived Asset Impairments (net of taxes of $68, $1 and $67, respectively) (5)	0.11	103	—	—	—	—	1	104
Plant Retirements and Divestitures (net of taxes of $214) (6)	0.37	338	—	—	—	—	—	338
Reassessment of State Deferred Income Taxes (entire amount represents tax expense) (7)	—	6	—	—	—	—	(6)	—
Cost Management Program (net of taxes of $13, $2, $2 and $17, respectively) (8)	0.03	22	—	2	2	—	—	26
Like-Kind Exchange Tax Position (net of taxes of $42, $19 and $61, respectively) (9)	0.21	—	149	—	—	—	50	199
Noncontrolling Interests (net of taxes of $8) (10)	0.04	41	—	—	—	—	—	41
2016 Adjusted (non-GAAP) Operating Earnings (Loss)	**2.24**	**1,018**	**443**	**350**	**184**	**185**	**(102)**	**2,078**
Year Over Year Effects on Earnings:								
ComEd, PECO, BGE and PHI Margins:								
Weather	(0.07)	—	(22) (c)	(28)	— (c)	(12) (c)	—	(62)
Load	(0.01)	—	(7) (c)	(4)	— (c)	4 (c)	—	(7)
Other Energy Delivery (14)	0.60	—	90 (d)	(4) (d)	49 (d)	431 (d)	—	566
Generation Energy Margins, Excluding Mark-to-Market:								
Nuclear Volume (15)	0.07	69	—	—	—	—	—	69
Nuclear Fuel Cost (16)	0.01	12	—	—	—	—	—	12
Capacity Pricing (17)	0.02	15	—	—	—	—	—	15
Zero Emission Credit Revenue (18)	0.13	118	—	—	—	—	—	118
Market and Portfolio Conditions (19)	(0.35)	(329)	—	—	—	—	—	(329)
Operating and Maintenance Expense:								
Labor, Contracting and Materials (20)	(0.13)	(46)	7	(8)	1	(83)	—	(129)
Planned Nuclear Refueling Outages (21)	(0.07)	(65)	—	—	—	—	—	(65)
Pension and Non-Pension Postretirement Benefits (22)	(0.01)	(2)	(1)	1	2	(5)	(2)	(7)
Other Operating and Maintenance (23)	(0.03)	(37)	4	13	35	(62)	19	(28)
Depreciation and Amortization Expense (24)	(0.19)	(16)	(34)	(7)	(24)	(92)	(6)	(179)
Interest Expense, Net (25)	(0.08)	(28)	5	(1)	(3)	(29)	(18)	(74)
Income Taxes (26)	(0.02)	(24)	(13)	14	(9)	5	4	(23)
Equity in Earnings of Unconsolidated Affiliates	(0.01)	(6)	—	—	—	—	—	(6)
Noncontrolling Interests (27)	0.03	25	—	—	—	—	—	25
Other (28)	(0.04)	17	(4)	6	1	(52)	(7)	(39)
Share Differential (29)	(0.04)	—	—	—	—	—	—	—
2017 Adjusted (non-GAAP) Operating Earnings (Loss)	**2.05**	**721**	**468**	**332**	**236**	**290**	**(112)**	**1,935**
2017 Adjusted (non-GAAP) Operating (Earnings) Loss Adjustments:								
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $62)	(0.10)	(98)	—	—	—	—	1	(97)
Unrealized Gains Related to NDT Fund Investments (net of taxes of $137) (1)	0.22	211	—	—	—	—	—	211
Amortization of Commodity Contract Intangibles (net of taxes of $17) (2)	(0.03)	(27)	—	—	—	—	—	(27)
Merger and Integration Costs (net of taxes of $28, $0, $1, $1, $6, $0 and $24, respectively) (3)	(0.04)	(44)	(1)	(2)	(2)	11	(1)	(39)
Merger Commitments (net of taxes of $18, $52, $67 and $137, respectively) (4)	0.15	18	—	—	—	59	60	137
Long-Lived Asset Impairments (net of taxes of $187, $1 and $188, respectively) (5)	(0.31)	(294)	—	—	—	—	1	(293)
Plant Retirements and Divestitures (net of taxes of $88, $1 and $89, respectively) (6)	(0.15)	(138)	—	—	—	—	1	(137)
Reassessment of State Deferred Income Taxes (entire amount represents tax expense) (7)	0.04	(18)	3	—	—	(1)	58	42
Cost Management Program (net of taxes of $11, $2, $2, $0 and $15, respectively) (8)	(0.03)	(17)	—	(3)	(3)	—	(1)	(24)
Like-Kind Exchange Tax Position (net of taxes of $9, $75 and $66, respectively) (9)	0.03	—	(23)	—	—	—	49	26
Asset Retirement Obligation (net of taxes of $1) (11)	—	2	—	—	—	—	—	2
Tax Settlements (net of taxes of $1) (12)	0.01	5	—	—	—	—	—	5
Bargain Purchase Gain (net of taxes of $0) (13)	0.25	233	—	—	—	—	—	233
Noncontrolling Interests (net of taxes of $16) (10)	(0.08)	(75)	—	—	—	—	—	(75)
2017 GAAP Net Income	**$ 2.01**	**$ 479**	**$ 447**	**$ 327**	**$ 231**	**$ 359**	**$ 56**	**$ 1,899**

Note:
Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net Income and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates for each Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. For all items except the unrealized gains and losses related to NDT fund investments, the marginal statutory income tax rates ranged from 39.0 percent to 41.0 percent. Under IRS regulations, NDT fund investment returns are taxed at differing rates for investments in qualified vs. non-qualified funds. The tax rates applied to unrealized gains and losses related to NDT fund investments were 46.2 percent and 52.5 percent for the nine months ended September 30, 2017 and 2016, respectively.

(a) For the nine months ended September 30, 2016, includes financial results for PHI beginning on March 24, 2016, the day after the merger was completed. Therefore, the results of operations from 2017 and 2016 are not comparable for PHI and Exelon. The explanations below identify any other significant or unusual items affecting the results of operations. PHI consolidated results includes Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company.
(b) Other primarily includes eliminating and consolidating adjustments, Exelon's corporate operations, shared service entities and other financing and investment activities.
(c) As approved by the Maryland PSC and District of Columbia PSC, customer rates for BGE, Pepco and DPL Maryland are adjusted to eliminate the favorable and unfavorable impacts of weather and usage patterns per customer on distribution volumes. Pursuant to the Illinois Future Energy Jobs Act, beginning in 2017, customer rates for ComEd are adjusted to eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution volumes.
(d) For regulatory recovery mechanisms, including ComEd's distribution formula rate, ComEd, BGE and PHI utilities transmission formula rates, and riders across all utilities, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).
(1) Reflects the impact of unrealized gains on NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements.
(2) Represents the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value related to the Integrys and ConEdison Solutions acquisitions in 2016, and in 2017, the ConEdison Solutions and FitzPatrick acquisitions.
(3) Reflects certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI acquisition in 2016, partially offset at ComEd, BGE and PHI by the anticipated recovery of previously incurred PHI acquisition costs, and in 2017, the PHI and FitzPatrick acquisitions, partially offset at PHI by the anticipated recovery of previously incurred PHI acquisition costs.
(4) Primarily reflects in 2016 costs incurred as part of the settlement orders approving the PHI acquisition, and in 2017, a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions.
(5) Primarily reflects charges to earnings related to the impairment of upstream assets and certain wind projects at Generation in 2016, and in 2017, impairments as a result of the ExGen Texas Power, LLC assets held for sale.
(6) Primarily reflects accelerated depreciation and amortization expenses, increases to materials and supplies inventory reserves, charges for severance reserves and construction work in progress impairments associated with Generation's previous decision to early retire the Clinton and Quad Cities nuclear facilities in 2016, and Generation's decision to early retire the Three Mile Island nuclear facility in 2017, partially offset in 2016 by a gain associated with Generation's sale of the New Boston generating site.
(7) Reflects the non-cash impact of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment related to the PHI acquisition in 2016, and in 2017, changes in the Illinois and District of Columbia statutory tax rates and changes in forecasted apportionment.
(8) Represents severance and reorganization costs related to a cost management program.
(9) Represents the recognition of a penalty and associated interest expense in 2016 as a result of a tax court decision on Exelon's like-kind exchange tax position, and adjustments to income tax, penalties and interest expenses in 2017 as a result of the finalization of the IRS tax computation related to Exelon's like-kind exchange tax position.
(10) Represents elimination from Generation's results of the noncontrolling interests related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.
(11) Primarily reflects a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units.
(12) Reflects benefits related to the favorable settlement in 2017 of certain income tax positions related to PHI's unregulated business interests that were transferred to Generation.
(13) Represents the excess of the fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition.
(14) For ComEd, primarily reflects increased electric distribution and transmission formula rate revenues (due to increased capital investments and higher electric distribution ROE, which is due to an increase in treasury rates), partially offset by lower revenues resulting from the change to defer and recover over time energy efficiency costs pursuant to the Illinois Future Energy Jobs Act. For BGE and PHI, primarily reflects increased revenue as a result of rate increases.
(15) Primarily reflects the acquisition of the FitzPatrick nuclear facility.
(16) Primarily reflects a decrease in fuel prices, partially offset by an increase in nuclear output as a result of the FitzPatrick acquisition.
(17) Primarily reflects increased capacity prices in the New England region, partially offset by decreased capacity prices in the Mid-Atlantic region.
(18) Reflects the impact of the New York Clean Energy Standard.
(19) Primarily reflects the conclusion of the Ginna Reliability Support Services Agreement, the impact of declining natural gas prices on Generation's natural gas portfolio, the impacts of lower load volumes delivered due to mild weather and lower realized energy prices related to Exelon's ratable hedging strategy, partially offset by the addition of two combined-cycle gas turbines in Texas and the absence of oil inventory write downs in 2017.
(20) For Generation, primarily reflects increased salaries, wages and contracting costs related to the acquisition of the FitzPatrick nuclear facility.
(21) Primarily reflects an increase in the number of nuclear outage days in 2017, excluding Salem.
(22) Primarily reflects the unfavorable impact of lower pension and OPEB discount rates, partially offset by the favorable impact of lower health care claims experience.
(23) For Generation, includes an increase in nuclear decommissioning obligation expense related to the FitzPatrick nuclear facility. For ComEd, primarily reflects the change to defer and recover over time energy efficiency costs pursuant to the Illinois Future Energy Jobs Act. For PECO, primarily reflects decreased fully recoverable costs associated with regulatory programs. For BGE, primarily reflects certain disallowances contained in 2016 rate case orders and decreased storm costs in the BGE service territory.
(24) For Generation, reflects increased depreciation for the addition of two combined-cycle gas turbines in Texas, offset by the absence of depreciation due to the EGTP assets held for sale. For BGE, primarily reflects increased amortization due to the initiation of cost recovery of the AMI programs and increased depreciation from AMI program capital expenditures. Additionally, primarily reflects increased depreciation from ongoing capital expenditures across all operating companies.

(25) For Generation, primarily reflects the impact of project in-service dates on the capitalization of interest and higher outstanding debt. For Corporate, primarily reflects increased interest expense due to higher outstanding debt, as well as debt issuance costs related to the April 2017 remarketing of Junior Subordinated Notes due in 2024.
(26) For Generation, primarily reflects the favorable settlement of certain income tax positions in 2016. For ComEd, reflects the 2017 increase in the Illinois statutory income tax rate. For PECO, primarily reflects an increase in the repairs tax deduction. For BGE, primarily reflects a 2016 cumulative adjustment to tax expense for transmission-related regulatory assets.
(27) Reflects elimination from Generation's results of activity attributable to noncontrolling interests, primarily for CENG and the Renewables Joint Venture.
(28) For Generation, primarily reflects higher realized NDT fund gains, partially offset by increased real estate taxes as a result of the FitzPatrick acquisition.
(29) Reflects the impact on earnings per share due to the increase in Exelon's average diluted common shares outstanding as a result of the June 2017 common stock issuance.

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Generation

	Three Months Ended September 30, 2017			Three Months Ended September 30, 2016		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 4,751	$ (39)	(b),(d)	$ 5,035	$ (166)	(b),(d)
Operating expenses						
Purchased power and fuel	2,331	9	(b),(d),(h)	2,589	(127)	(b),(d),(h)
Operating and maintenance	1,374	(68)	(e),(g),(h),(j),(l)	1,336	(6)	(e),(g),(h),(j)
Depreciation and amortization	410	(106)	(h)	632	(338)	(e),(h)
Taxes other than income	141	—		136	—	
Total operating expenses	4,256			4,693		
Gain on sales of assets	(2)	2	(h)	—	—	
Bargain purchase gain	7	(7)	(n)	—	—	
Operating income	500			342		
Other income and (deductions)						
Interest expense, net	(113)	—		(77)	—	
Other, net	209	(118)	(c)	185	(145)	(c)
Total other income and (deductions)	96			108		
Income before income taxes	596			450		
Income taxes	240	(19)	(b),(c),(d),(e),(g),(h),(i)(j),(l)	173	43	(b),(c),(d),(e),(g),(h),(j)
Equity in losses of unconsolidated affiliates	(8)	—		(6)	—	
Net income	348			271		
Net income attributable to noncontrolling interests	43	(20)	(k)	35	(23)	(k)
Net income attributable to membership interest	$ 305			$ 236		

	Nine Months Ended September 30, 2017			Nine Months Ended September 30, 2016		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 13,812	$ 77	(b), (d)	$ 13,363	$ 376	(b),(d)
Operating expenses						
Purchased power and fuel	7,286	(133)	(b),(d),(h)	6,609	211	(b),(d),(h)
Operating and maintenance	4,871	(630)	(e),(g),(h),(j),(l)	4,333	(335)	(e),(f),(g),(h),(j)
Depreciation and amortization	1,046	(143)	(d),(h)	1,329	(452)	(e),(h)
Taxes other than income	425	—		380	(1)	(j)
Total operating expenses	13,628			12,651		
Gain on sales of assets	3	1	(h)	31	—	
Bargain purchase gain	233	(233)	(n)	—	—	
Operating income	420			743		
Other income and (deductions)						
Interest expense, net	(342)	18	(g),(m)	(273)	—	
Other, net	648	(392)	(c)	395	(299)	(c),(h)
Total other income and (deductions)	306			122		
Income before income taxes	726			865		
Income taxes	209	210	(b),(c),(d),(e),(f),(g),(h),(i),(j),(l),(m)	293	215	(b),(c),(d),(e),(f),(g),(h),(i),(j)
Equity in losses of unconsolidated affiliates	(26)	—		(16)	—	
Net income	491			556		
Net income attributable to noncontrolling interests	12	(75)	(k)	18	(41)	(k)
Net income attributable to membership interest	$ 479			$ 538		

(a) Results reported in accordance with GAAP.
(b) Adjustment to exclude the mark-to-market impact of Exelon’s economic hedging activities, net of intercompany eliminations.
(c) Adjustment to exclude the unrealized gains on NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements.
(d) Adjustment to exclude the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value related to the Integrys and ConEdison Solutions acquisitions in 2016, and in 2017, the ConEdison Solutions and FitzPatrick acquisitions.
(e) Adjustment to exclude costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI acquisition in 2016, partially offset at ComEd, BGE and PHI by the anticipated recovery of previously incurred PHI acquisition costs, and in 2017, the PHI and FitzPatrick acquisitions, partially offset at PHI by the anticipated recovery of previously incurred PHI acquisition costs.
(f) Adjustment to exclude 2016 costs incurred as part of the settlement orders approving the PHI acquisition, and in 2017, a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions.
(g) Adjustment to exclude charges to earnings related to the impairment of upstream assets and certain wind projects at Generation in 2016, and in 2017, impairments as a result of the ExGen Texas Power, LLC assets held for sale.
(h) Adjustment to exclude accelerated depreciation and amortization expenses, increases to materials and supplies inventory reserves, charges for severance reserves and construction work in progress impairments associated with Generation's previous decision to early retire the Clinton and Quad Cities nuclear facilities in 2016, and Generation's decision to early retire the Three Mile Island nuclear facility in 2017, partially offset in 2016 by a gain associated with Generation’s sale of the New Boston generating site.
(i) Adjustment to exclude the non-cash impact of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment related to the PHI acquisition in 2016, and in 2017, changes in the Illinois and District of Columbia statutory tax rates and changes in forecasted apportionment.
(j) Adjustment to exclude severance and reorganization costs related to a cost management program.
(k) Adjustment to exclude from Generation’s results the noncontrolling interests related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.
(l) Adjustment to exclude a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units.
(m) Adjustment to exclude benefits related to the favorable settlement in 2017 of certain income tax positions related to PHI's unregulated business interests that were transferred to Generation.
(n) Adjustments to exclude the excess of the fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition.

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ComEd

	Three Months Ended September 30, 2017			Three Months Ended September 30, 2016		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 1,571	$ —		$ 1,497	$ —	
Operating expenses						
Purchased power and fuel	529	—		454	—	
Operating and maintenance	346	—		377	—	
Depreciation and amortization	212	—		196	—	
Taxes other than income	80	—		82	—	
Total operating expenses	1,167			1,109		
Gain on sales of assets	—	—		1	—	
Operating income	404			389		
Other income and (deductions)						
Interest expense, net	(89)	—		(197)	105	(c)
Other, net	5	—		(80)	86	(c)
Total other income and (deductions)	(84)			(277)		
Income before income taxes	320			112		
Income taxes	131	3	(d)	75	42	(c)
Net income	$ 189			$ 37		

	Nine Months Ended September 30, 2017			Nine Months Ended September 30, 2016		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 4,227	$ —		$ 4,031	$ (8)	(b)
Operating expenses						
Purchased power and fuel	1,241	—		1,141	—	
Operating and maintenance	1,096	(1)	(b)	1,113	(2)	(b)
Depreciation and amortization	631	—		574	—	
Taxes other than income	223	—		222	—	
Total operating expenses	3,191			3,050		
Gain on sales of assets	—	—		6	—	
Operating income	1,036			987		
Other income and (deductions)						
Interest expense, net	(275)	14	(c)	(374)	105	(c)
Other, net	14	—		(72)	86	(c)
Total other income and (deductions)	(261)			(446)		
Income before income taxes	775			541		
Income taxes	328	(6)	(b),(c),(d)	244	39	(b),(c)
Net income	$ 447			$ 297		

(a) Results reported in accordance with GAAP.
(b) Adjustment to exclude certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI acquisition, partially offset in 2016 at ComEd by the anticipated recovery of previously incurred PHI acquisition costs.
(c) Adjustment to exclude the recognition of a penalty and associated interest expense in 2016 as a result of a tax court decision on Exelon's like-kind exchange tax position, and adjustments to income tax, penalties and interest expenses in 2017 as a result of the finalization of the IRS tax computation related toExelon's like-kind exchange tax position.

(d) Adjustment to exclude the non-cash impact of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment related to changes in the Illinois statutory tax rate and changes in forecasted apportionment.

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PECO

	Three Months Ended September 30, 2017			Three Months Ended September 30, 2016		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 715	$ —		$ 788	$ —	
Operating expenses						
Purchased power and fuel	235	—		272	—	
Operating and maintenance	197	(3)	(c)	199	(2)	(b)
Depreciation and amortization	72	—		67	—	
Taxes other than income	42	—		46	—	
Total operating expenses	546			584		
Operating income	169			204		
Other income and (deductions)						
Interest expense, net	(31)	—		(30)	—	
Other, net	2	—		2	—	
Total other income and (deductions)	(29)			(28)		
Income before income taxes	140			176		
Income taxes	28	1	(c)	54	1	(b)
Net income	$ 112			$ 122		

	Nine Months Ended September 30, 2017			Nine Months Ended September 30, 2016		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 2,141	$ —		$ 2,293	$ —	
Operating expenses						
Purchased power and fuel	719	—		809	—	
Operating and maintenance	595	(8)	(b),(c)	604	(7)	(b),(c)
Depreciation and amortization	213	—		201	—	
Taxes other than income	116	—		126	—	
Total operating expenses	1,643			1,740		
Operating income	498			553		
Other income and (deductions)						
Interest expense, net	(93)	—		(92)	—	
Other, net	6	—		6	—	
Total other income and (deductions)	(87)			(86)		
Income before income taxes	411			467		
Income taxes	84	3	(b),(c)	121	3	(b),(c)
Net income	$ 327			$ 346		

(a) Results reported in accordance with GAAP.
(b) Adjustment to exclude certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI acquisition.
(c) Adjustment to exclude reorganization costs related to a cost management program.

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BGE

	Three Months Ended September 30, 2017			Three Months Ended September 30, 2016		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 738	$ —		$ 812	$ —	
Operating expenses						
Purchased power and fuel	269	—		360	—	
Operating and maintenance	175	(4)	(c)	178	(1)	(b)
Depreciation and amortization	109	—		101	—	
Taxes other than income	61	—		58	—	
Total operating expenses	614			697		
Operating income	124			115		
Other income and (deductions)						
Interest expense, net	(26)	—		(28)	—	
Other, net	4	—		5	—	
Total other income and (deductions)	(22)			(23)		
Income before income taxes	102			92		
Income taxes	40	2	(c)	36	—	
Net income	62			56		
Preference stock dividends	—			2		
Net income attributable to common shareholder	$ 62			$ 54		

	Nine Months Ended September 30, 2017			Nine Months Ended September 30, 2016		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 2,363	$ —		$ 2,421	$ —	
Operating expenses						
Purchased power and fuel	853	—		994	—	
Operating and maintenance	532	(9)	(b),(c)	588	(2)	(b),(c)
Depreciation and amortization	348	—		307	—	
Taxes other than income	180	—		172	—	
Total operating expenses	1,913			2,061		
Operating income	450			360		
Other income and (deductions)						
Interest expense, net	(80)	—		(76)	—	
Other, net	12	—		16	—	
Total other income and (deductions)	(68)			(60)		
Income before income taxes	382			300		
Income taxes	151	4	(b),(c)	109	1	(b),(c)
Net income	231			191		
Preference stock dividends	—			8		
Net income attributable to common shareholder	$ 231			$ 183		

(a) Results reported in accordance with GAAP.

(b) Adjustment to exclude certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI acquisition, partially offset in 2016 at BGE by the anticipated recovery of previously incurred PHI acquisition costs.
(c) Adjustment to exclude reorganization costs related to a cost management program.

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PHI

	Three Months Ended September 30, 2017			Three Months Ended September 30, 2016		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 1,310	$ —		$ 1,394	$ —	
Operating expenses						
Purchased power and fuel	473	—		583	—	
Operating and maintenance	251	15	(c)	226	43	(c),(d)
Depreciation and amortization	179	—		182	—	
Taxes other than income	122	—		124	—	
Total operating expenses	1,025			1,115		
Operating income	285			279		
Other income and (deductions)						
Interest expense, net	(62)	—		(64)	—	
Other, net	13	—		19	—	
Total other income and (deductions)	(49)			(45)		
Income before income taxes	236			234		
Income taxes	83	(8)	(c),(e)	68	(7)	(c),(d)
Net income	$ 153			$ 166		

	Nine Months Ended September 30, 2017			Nine Months Ended September 30, 2016 (b)		
	GAAP (a)	Non-GAAP Adjustments		GAAP (a)	Non-GAAP Adjustments	
Operating revenues	$ 3,557	$ —		$ 2,565	$ —	
Operating expenses						
Purchased power and fuel	1,318	—		1,037	—	
Operating and maintenance	774	25	(c),(d)	921	(375)	(c),(d)
Depreciation and amortization	511	—		355	—	
Taxes other than income	344	—		248	—	
Total operating expenses	2,947			2,561		
Gain on sales of assets	1	—		—	—	
Operating income (loss)	611			4		
Other income and (deductions)						
Interest expense, net	(183)	—		(135)	—	
Other, net	40	—		31	—	
Total other income and (deductions)	(143)			(104)		
Income (loss) before income taxes	468			(100)		
Income taxes	109	44	(c),(d),(e)	(9)	99	(c),(d)
Net income (loss)	$ 359			$ (91)		

(a) Results reported in accordance with GAAP.
(b) For the nine months ended September 30, 2016, includes financial results for PHI beginning on March 24, 2016, the day after the merger was completed. Therefore, the results of operations from 2017 and 2016 are not comparable for PHI and Exelon. The explanations below identify any other significant or unusual items affecting the results of operations. PHI consolidated results includes Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company.
(c) Adjustment to exclude certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI acquisition, partially offset in 2016 and 2017 at PHI by the anticipated recovery of previously incurred acquisition costs.

(d) Adjustment to exclude in 2016 costs incurred as part of the settlement orders approving the PHI acquisition, and in 2017, a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2016 PHI acquisition.

(e) Adjustment to exclude the non-cash impact of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment.

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Other (a)

	Three Months Ended September 30, 2017			Three Months Ended September 30, 2016		
	GAAP (b)	**Non-GAAP Adjustments**		**GAAP (b)**	**Non-GAAP Adjustments**	
Operating revenues	$ (316)	$ —		$ (524)	$ —	
Operating expenses						
Purchased power and fuel	(295)	—		(504)	—	
Operating and maintenance	(43)	—		22	(57)	(e)
Depreciation and amortization	20	—		17	—	
Taxes other than income	10	—		3	—	
Total operating expenses	(308)			(462)		
Gain on sales of assets	1	—		—	—	
Operating loss	(7)			(62)		
Other income and (deductions)						
Interest expense, net	(65)	—		(120)	48	(j)
Other, net	4	—		(11)	20	(j)
Total other income and (deductions)	(61)			(131)		
Loss before income taxes	(68)			(193)		
Income taxes	(70)	39	(c),(d),(f),(g),(h),(i)	(66)	29	(e),(f),(j)
Equity in earnings of unconsolidated affiliates	1	—		1	—	
Net income (loss)	3			(126)		
Net loss attributable to noncontrolling interests and preference stock dividends	—			(1)	—	
Net income (loss) attributable to common shareholders	$ 3			$ (125)		

	Nine Months Ended September 30, 2017			Nine Months Ended September 30, 2016		
	GAAP (b)	**Non-GAAP Adjustments**		**GAAP (b)**	**Non-GAAP Adjustments**	
Operating revenues	$ (951)	$ —		$ (1,187)	$ —	
Operating expenses						
Purchased power and fuel	(890)	—		(1,128)	—	
Operating and maintenance	(136)	(10)	(d),(e),(i)	118	(235)	(d),(e)
Depreciation and amortization	65	—		55	—	
Taxes other than income	25	—		20	—	
Total operating expenses	(936)			(935)		
Gain on sales of assets	—	—		4	—	
Operating loss	(15)			(248)		
Other income and (deductions)						
Interest expense, net	(221)	27	(j)	(229)	48	(j)
Other, net	5	(1)	(j)	1	20	(j)
Total other income and (deductions)	(216)			(228)		
Loss before income taxes	(231)			(476)		
Income taxes	(286)	204	(c),(d),(e),(f),(g),(h),(i),(j)	(133)	62	(d),(e),(f),(h),(j)
Equity in earnings of unconsolidated affiliates	1	—		—	—	
Net income (loss) attributable to common shareholders	$ 56			$ (343)		

(a) Other primarily includes eliminating and consolidating adjustments, Exelon's corporate operations, shared service entities and other financing and investment activities.

(b) Results reported in accordance with GAAP.
(c) Adjustment to exclude the mark-to-market impact of Exelon’s economic hedging activities, net of intercompany eliminations.
(d) Adjustment to exclude certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI acquisition.
(e) Adjustment to exclude in 2016 costs incurred as part of the settlement orders approving the PHI acquisition, and in 2017, a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2016 PHI acquisition.
(f) Adjustment to exclude the impact of charges to earnings related to the impairment of upstream assets and certain wind projects at Generation in 2016, and in 2017, impairments as a result of the ExGen Texas Power, LLC assets held for sale.
(g) Adjustment to exclude the impact associated with Generation's decision to early retire the Three Mile Island nuclear facility in 2017.
(h) Adjustment to exclude the non-cash impact of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment related to the PHI acquisition in 2016, and in 2017, changes in the Illinois and District of Columbia statutory tax rates and changes in forecasted apportionment.
(i) Adjustment to exclude reorganization costs related to a cost management program.
(j) Adjustment to exclude the recognition of a penalty and associated interest expense in 2016 as a result of a tax court decision on Exelon's like-kind exchange tax position, and adjustments to income tax, penalties and interest expenses in 2017 as a result of the finalization of the IRS tax computation related to Exelon's like-kind exchange tax position.

EXELON CORPORATION
Exelon Generation Statistics

	Three Months Ended				
	September 30, 2017	June 30, 2017	March 31, 2017	December 31, 2016	September 30, 2016
Supply (in GWhs)					
Nuclear Generation					
Mid-Atlantic[a]	16,480	15,246	16,545	16,410	15,604
Midwest	24,362	22,592	22,468	23,743	24,262
New York[a][f]	6,905	6,227	4,491	4,681	4,843
Total Nuclear Generation	47,747	44,065	43,504	44,834	44,709
Fossil and Renewables					
Mid-Atlantic	596	899	836	442	706
Midwest	218	417	418	442	273
New England	1,919	1,925	2,077	1,142	1,886
New York	1	1	1	1	1
ERCOT	5,703	2,315	1,370	1,056	2,472
Other Power Regions[b]	2,149	2,084	1,423	1,935	2,103
Total Fossil and Renewables	10,586	7,641	6,125	5,018	7,441
Purchased Power					
Mid-Atlantic	2,541	2,901	3,398	2,849	7,139
Midwest	217	413	388	400	461
New England	4,513	4,343	5,064	4,768	3,927
New York	—	—	28	—	—
ERCOT	1,199	1,871	2,655	3,189	2,895
Other Power Regions[b]	3,982	3,507	2,868	3,308	3,803
Total Purchased Power	12,452	13,035	14,401	14,514	18,225
Total Supply/Sales by Region[c]					
Mid-Atlantic[d]	19,617	19,046	20,779	19,701	23,449
Midwest[d]	24,797	23,422	23,274	24,585	24,996
New England	6,432	6,268	7,141	5,910	5,813
New York	6,906	6,228	4,520	4,682	4,844
ERCOT	6,902	4,186	4,025	4,245	5,367
Other Power Regions[b]	6,131	5,591	4,291	5,243	5,906
Total Supply/Sales by Region	70,785	64,741	64,030	64,366	70,375

	Three Months Ended				
	September 30, 2017	June 30, 2017	March 31, 2017	December 31, 2016	September 30, 2016
Outage Days[e]					
Refueling[f]	13	125	95	71	17
Non-refueling[f]	15	12	8	32	—
Total Outage Days	28	137	103	103	17

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG).
(b) Other Power Regions includes, South, West and Canada.
(c) Excludes physical proprietary trading volumes of 2,601 GHhs, 2,312 GWhs, 1,850 GWhs, 2,164 GWhs, and 1,506 GWhs for the three months ended September 30, 2017, June 30, 2017, March 31, 2017, December 31, 2016, and September 30, 2016, respectively.
(d) Includes affiliate sales to PECO, BGE, Pepco, DPL and ACE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region.
(e) Outage days exclude Salem.
(f) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

EXELON CORPORATION
Exelon Generation Statistics
Nine Months Ended September 30, 2017 and 2016

	September 30, 2017	September 30, 2016
Supply (in GWhs)		
Nuclear Generation		
Mid-Atlantic[(a)]	48,271	47,035
Midwest	69,422	70,925
New York[(a)(d)]	17,623	14,002
Total Nuclear Generation	135,316	131,962
Fossil and Renewables		
Mid-Atlantic	2,330	2,290
Midwest	1,053	1,046
New England	5,921	5,826
New York	3	3
ERCOT	9,388	5,726
Other Power Regions	5,656	6,245
Total Fossil and Renewables	24,351	21,136
Purchased Power		
Mid-Atlantic	8,840	14,024
Midwest	1,018	1,855
New England	13,920	11,863
New York	28	—
ERCOT	5,724	7,448
Other Power Regions	10,357	10,281
Total Purchased Power	39,887	45,471
Total Supply/Sales by Region[(b)]		
Mid-Atlantic[(c)]	59,441	63,349
Midwest[(c)]	71,493	73,826
New England	19,841	17,689
New York	17,654	14,005
ERCOT	15,112	13,174
Other Power Regions	16,013	16,526
Total Supply/Sales by Region	199,554	198,569

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG).
(b) Excludes physical proprietary trading volumes of 6,763 GWh and 4,015 GWh for the nine months ended September 30, 2017 and 2016, respectively.
(c) Includes affiliate sales to PECO, BGE, Pepco, DPL and ACE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region.
(d) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

EXELON CORPORATION
ComEd Statistics
Three Months Ended September 30, 2017 and 2016

	Electric Deliveries (in GWhs)				Revenue (in millions)		
	2017	2016	% Change	Weather-Normal % Change	2017	2016	% Change
Retail Deliveries and Sales (a)							
Residential	8,004	9,014	(11.2)%	(0.6)%	$ 825	$ 786	5.0 %
Small Commercial & Industrial	8,488	8,833	(3.9)%	(1.0)%	369	356	3.7 %
Large Commercial & Industrial	7,232	7,565	(4.4)%	(2.5)%	121	126	(4.0)%
Public Authorities & Electric Railroads	302	308	(1.9)%	(1.7)%	11	10	10.0 %
Total Retail	24,026	25,720	(6.6)%	(1.3)%	1,326	1,278	3.8 %
Other Revenue (b)					245	219	11.9 %
Total Electric Revenue (c)					$ 1,571	$ 1,497	4.9 %
Purchased Power					$ 529	$ 454	16.5 %

				% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	From 2016	From Normal
Heating Degree-Days	42	23	97	82.6 %	(56.7)%
Cooling Degree-Days	699	840	641	(16.8)%	9.0 %

Nine Months Ended September 30, 2017 and 2016

	Electric Deliveries (in GWhs)				Revenue (in millions)		
	2017	2016	% Change	Weather-Normal % Change	2017	2016	% Change
Retail Deliveries and Sales (a)							
Residential	20,164	21,738	(7.2)%	(1.3)%	$ 2,108	$ 2,018	4.5%
Small Commercial & Industrial	23,634	24,447	(3.3)%	(1.6)%	1,051	1,007	4.4%
Large Commercial & Industrial	20,712	21,057	(1.6)%	(0.5)%	352	350	0.6%
Public Authorities & Electric Railroads	928	947	(2.0)%	(1.4)%	34	33	3.0%
Total Retail	65,438	68,189	(4.0)%	(1.1)%	3,545	3,408	4.0%
Other Revenue (b)					682	623	9.5%
Total Electric Revenue (c)					$ 4,227	$ 4,031	4.9%
Purchased Power					$ 1,241	$ 1,141	8.8%

				% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	From 2016	From Normal
Heating Degree-Days	3,269	3,678	3,972	(11.1)%	(17.7)%
Cooling Degree-Days	962	1,130	882	(14.9)%	9.1 %

Number of Electric Customers	2017	2016
Residential	3,610,091	3,578,846
Small Commercial & Industrial	376,309	372,603
Large Commercial & Industrial	1,954	2,010
Public Authorities & Electric Railroads	4,763	4,738
Total	3,993,117	3,958,197

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.
(b) Other revenue primarily includes transmission revenue from PJM. Other revenue includes rental revenues, revenues related to late payment charges, revenues from other utilities for mutual assistance programs and recoveries of remediation costs associated with MGP sites.
(c) Includes operating revenues from affiliates totaling $3 million and $4 million for the three months ended September 30, 2017 and 2016, respectively, and $12 million and $12 million for the nine months ended September 30, 2017 and 2016, respectively.

EXELON CORPORATION
PECO Statistics
Three Months Ended September 30, 2017 and 2016

	Electric and Natural Gas Deliveries				Revenue (in millions)		
	2017	2016	% Change	Weather-Normal % Change	2017	2016	% Change
Electric (in GWhs)							
Retail Deliveries and Sales (a)							
Residential	3,752	4,358	(13.9)%	0.2 %	$ 434	$ 513	(15.4)%
Small Commercial & Industrial	2,158	2,324	(7.1)%	(1.0)%	106	109	(2.8)%
Large Commercial & Industrial	4,137	4,234	(2.3)%	1.4 %	59	59	— %
Public Authorities & Electric Railroads	198	240	(17.5)%	(17.5)%	7	8	(12.5)%
Total Retail	10,245	11,156	(8.2)%	— %	606	689	(12.0)%
Other Revenue (b)					56	51	9.8 %
Total Electric Revenue (d)					662	740	(10.5)%
Natural Gas (in mmcfs)							
Retail Deliveries and Sales							
Retail Sales (c)	3,993	3,494	14.3 %	9.4 %	46	41	12.2 %
Transportation and Other	5,674	7,315	(22.4)%	(14.5)%	7	7	— %
Total Natural Gas (d)	9,667	10,809	(10.6)%	(6.0)%	53	48	10.4 %
Total Electric and Natural Gas Revenues					$ 715	$ 788	(9.3)%
Purchased Power and Fuel					$ 235	$ 272	(13.6)%

				% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	From 2016	From Normal
Heating Degree-Days	14	10	35	40.0 %	(60.0)%
Cooling Degree-Days	989	1,288	923	(23.2)%	7.2 %

Nine Months Ended September 30, 2017 and 2016

	Electric and Natural Gas Deliveries				Revenue (in millions)		
	2017	2016	% Change	Weather-Normal % Change	2017	2016	% Change
Electric (in GWhs)							
Retail Deliveries and Sales (a)							
Residential	9,939	10,682	(7.0)%	(1.4)%	$ 1,147	$ 1,278	(10.3)%
Small Commercial & Industrial	6,048	6,236	(3.0)%	(1.1)%	303	334	(9.3)%
Large Commercial & Industrial	11,593	11,598	— %	0.8 %	168	182	(7.7)%
Public Authorities & Electric Railroads	618	672	(8.0)%	(8.0)%	23	25	(8.0)%
Total Retail	28,198	29,188	(3.4)%	(0.6)%	1,641	1,819	(9.8)%
Other Revenue (b)					161	152	5.9 %
Total Electric Revenue (d)					1,802	1,971	(8.6)%
Natural Gas (in mmcfs)							
Retail Deliveries and Sales							
Retail Sales (c)	38,825	38,488	0.9 %	2.7 %	315	298	5.7 %
Transportation and Other	19,122	20,917	(8.6)%	(5.9)%	24	24	— %
Total Natural Gas (d)	57,947	59,405	(2.5)%	(0.1)%	339	322	5.3 %
Total Electric and Natural Gas Revenues					$ 2,141	$ 2,293	(6.6)%
Purchased Power and Fuel					$ 719	$ 809	(11.1)%

				% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	From 2016	From Normal
Heating Degree-Days	2,437	2,616	2,974	(6.8)%	(18.1)%
Cooling Degree-Days	1,404	1,684	1,271	(16.6)%	10.5 %

Number of Electric Customers	2017	2016	Number of Natural Gas Customers	2017	2016
Residential	1,463,906	1,451,533	Residential	474,766	470,024
Small Commercial & Industrial	150,964	149,646	Commercial & Industrial	43,358	42,997
Large Commercial & Industrial	3,112	3,094	Total Retail	518,124	513,021
Public Authorities & Electric Railroads	9,665	9,820	Transportation	771	802
Total	1,627,647	1,614,093	Total	518,895	513,823

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

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

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

(d) Total electric revenue includes operating revenues from affiliates totaling $1 million and $2 million for the three months ended September 30, 2017 and 2016, respectively, and $4 million and $5 million for the nine months ended September 30, 2017 and 2016, respectively. Total natural gas revenues includes operating revenues from affiliates totaling less than $1 million for both the three and nine months ended September 30, 2017 and 2016.

EXELON CORPORATION
BGE Statistics
Three Months Ended September 30, 2017 and 2016

	Electric and Natural Gas Deliveries				Revenue (in millions)		
	2017	2016	% Change	Weather-Normal % Change	2017	2016	% Change
Electric (in GWhs)							
Retail Deliveries and Sales (a)							
Residential	3,370	3,900	(13.6)%	(2.9)%	$ 376	$ 451	(16.6)%
Small Commercial & Industrial	785	877	(10.5)%	(9.0)%	67	74	(9.5)%
Large Commercial & Industrial	3,781	3,992	(5.3)%	(3.9)%	120	123	(2.4)%
Public Authorities & Electric Railroads	64	72	(11.1)%	(2.5)%	8	9	(11.1)%
Total Retail	8,000	8,841	(9.5)%	(4.0)%	571	657	(13.1)%
Other Revenue (b)(c)					87	78	11.5 %
Total Electric Revenue					658	735	(10.5)%
Natural Gas (in mmcfs)							
Retail Deliveries and Sales (d)							
Retail Sales	11,221	13,159	(14.7)%	(14.3)%	77	71	8.5 %
Transportation and Other (e)	68	1,311	(94.8)%	n/a	3	6	(50.0)%
Total Natural Gas (f)	11,289	14,470	(22.0)%	(14.3)%	80	77	3.9 %
Total Electric and Natural Gas Revenues					$ 738	$ 812	(9.1)%
Purchased Power and Fuel					$ 269	$ 360	(25.3)%

				% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	From 2016	From Normal
Heating Degree-Days	64	24	78	166.7 %	(17.9)%
Cooling Degree-Days	595	747	596	(20.3)%	(0.2)%

Nine Months Ended September 30, 2017 and 2016

	Electric and Natural Gas Deliveries				Revenue (in millions)		
	2017	2016	% Change	Weather-Normal % Change	2017	2016	% Change
Electric (in GWhs)							
Retail Deliveries and Sales (a)							
Residential	9,126	9,996	(8.7)%	(4.3)%	$ 1,096	$ 1,203	(8.9)%
Small Commercial & Industrial	2,210	2,343	(5.7)%	(5.8)%	202	212	(4.7)%
Large Commercial & Industrial	10,422	10,627	(1.9)%	(2.6)%	343	337	1.8 %
Public Authorities & Electric Railroads	204	215	(5.1)%	(2.5)%	23	27	(14.8)%
Total Retail	21,962	23,181	(5.3)%	(3.7)%	1,664	1,779	(6.5)%
Other Revenue (b)(c)					231	219	5.5 %
Total Electric Revenue					1,895	1,998	(5.2)%
Natural Gas (in mmcfs)							
Retail Deliveries and Sales (d)							
Retail Sales	60,620	69,415	(12.7)%	(5.3)%	445	403	10.4 %
Transportation and Other (e)	2,463	4,078	(39.6)%	n/a	23	20	15.0 %
Total Natural Gas (f)	63,083	73,493	(14.2)%	(5.3)%	468	423	10.6 %
Total Electric and Natural Gas Revenues					$ 2,363	$ 2,421	(2.4)%
Purchased Power and Fuel					$ 853	$ 994	(14.2)%

				% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	From 2016	From Normal
Heating Degree-Days	2,524	2,878	2,992	(12.3)%	(15.6)%
Cooling Degree-Days	877	966	850	(9.2)%	3.2 %

Number of Electric Customers	2017	2016	**Number of Natural Gas Customers**	2017	2016
Residential	1,156,659	1,145,020	Residential	626,039	619,837
Small Commercial & Industrial	113,224	112,609	Commercial & Industrial	43,973	43,957
Large Commercial & Industrial	12,144	12,030	Total Retail	670,012	663,794
Public Authorities & Electric Railroads	274	282	Transportation	—	—
Total	1,282,301	1,269,941	Total	670,012	663,794

(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) Other revenue primarily includes wholesale transmission revenue and late payment charges.
(c) Includes operating revenues from affiliates totaling $1 million for both the three months ended September 30, 2017 and 2016 and $5 million for both the nine months ended September 30, 2017 and 2016.
(d) Reflects delivery volumes and revenues 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. For customers purchasing natural gas from BGE, revenue also reflects the cost of natural gas.
(e) Transportation and other natural gas revenue includes off-system revenue of 68 mmcfs ($1 million) and 1,311 mmcfs ($4 million) for the three months ended September 30, 2017 and 2016, respectively, and 2,463 mmcfs ($15 million) and 4,078 mmcfs ($14 million) for the nine months ended September 30, 2017 and 2016, respectively.
(f) Includes operating revenues from affiliates totaling $2 million and $6 million for the three months ended September 30, 2017 and 2016, respectively, and $7 million and $11 million for the nine months ended September 30, 2017 and 2016, respectively.

EXELON CORPORATION
PEPCO Statistics
Three Months Ended September 30, 2017 and 2016

	Electric Deliveries				Revenue (in millions)		
	2017	2016	% Change	Weather - Normal % Change	2017	2016	% Change
Electric (in GWhs)							
Retail Deliveries and Sales (a)							
Residential	2,281	2,675	(14.7)%	(5.2)%	$ 283	$ 315	(10.2)%
Small Commercial & Industrial	347	394	(11.9)%	(7.2)%	38	43	(11.6)%
Large Commercial & Industrial	4,146	4,314	(3.9)%	0.8 %	221	219	0.9 %
Public Authorities & Electric Railroads	180	180	— %	1.1 %	8	7	14.3 %
Total Retail	6,954	7,563	(8.1)%	(1.7)%	550	584	(5.8)%
Other Revenue (b)					54	51	5.9 %
Total Electric Revenue (c)					604	635	(4.9)%
Purchased Power					$ 168	$ 213	(21.1)%

				% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	From 2016	From Normal
Heating Degree-Days	8	1	19	700.0 %	(57.9)%
Cooling Degree-Days	1,130	1,418	1,133	(20.3)%	(0.3)%

Nine Months Ended September 30, 2017 and 2016

	Electric Deliveries				Revenue (in millions)		
	2017	2016	% Change	Weather - Normal % Change	2017	2016	% Change
Electric (in GWhs)							
Retail Deliveries and Sales (a)							
Residential	6,038	6,652	(9.2)%	(2.7)%	$ 744	$ 791	(5.9)%
Small Commercial & Industrial	999	1,124	(11.1)%	(8.4)%	113	116	(2.6)%
Large Commercial & Industrial	11,306	11,890	(4.9)%	(3.0)%	608	613	(0.8)%
Public Authorities & Electric Railroads	542	544	(0.4)%	(0.2)%	24	23	4.3 %
Total Retail	18,885	20,210	(6.6)%	(3.1)%	1,489	1,543	(3.5)%
Other Revenue (b)					160	152	5.3 %
Total Electric Revenue (c)					1,649	1,695	(2.7)%
Purchased Power					$ 478	$ 563	(15.1)%

				% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	From 2016	From Normal
Heating Degree-Days	1,963	2,408	2,477	(18.5)%	(20.8)%
Cooling Degree-Days	1,679	1,872	1,611	(10.3)%	4.2 %

Number of Electric Customers	2017	2016
Residential	790,032	775,911
Small Commercial & Industrial	53,543	53,425
Large Commercial & Industrial	21,733	21,315
Public Authorities & Electric Railroads	143	129
Total	865,451	850,780

(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 September 30, 2017 and 2016, respectively, and $4 million and $3 million for the nine months ended September 30, 2017 and 2016, respectively.

EXELON CORPORATION
DPL Statistics
Three Months Ended September 30, 2017 and 2016

	Electric and Natural Gas Deliveries				Revenue (in millions)		
	2017	2016	% Change	Weather - Normal % Change	2017	2016	% Change
Electric (in GWhs)							
Retail Deliveries and Sales (a)							
Residential	1,439	1,601	(10.1)%	(2.2)%	$ 183	$ 200	(8.5)%
Small Commercial & Industrial	636	642	(0.9)%	3.2 %	49	48	2.1 %
Large Commercial & Industrial	1,245	1,250	(0.4)%	4.1 %	26	24	8.3 %
Public Authorities & Electric Railroads	10	9	11.1 %	11.1 %	3	2	50.0 %
Total Retail	3,330	3,502	(4.9)%	1.2 %	261	274	(4.7)%
Other Revenue (b)					48	40	20.0 %
Total Electric Revenue (c)					309	314	(1.6)%
Natural Gas (in mmcfs)							
Retail Deliveries and Sales (d)							
Retail Sales	1,069	1,121	(4.6)%	(6.4)%	12	13	(7.7)%
Transportation and Other (e)	1,197	1,166	2.7 %	2.4 %	6	4	50.0 %
Total Natural Gas	2,266	2,287	(0.9)%	(2.0)%	18	17	5.9 %
Total Electric and Natural Gas Revenues					$ 327	$ 331	(1.2)%
Purchased Power and Fuel					$ 129	$ 150	(14.0)%

Electric Service Territory				% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	From 2016	From Normal
Heating Degree-Days	24	14	33	71.4 %	(27.3)%
Cooling Degree-Days	867	1,103	856	(21.4)%	1.3 %

Gas Service Territory				% Change	
Heating Degree-Days	2017	2016	Normal	From 2016	From Normal
Heating Degree-Days	28	20	42	40.0%	(33.3)%

Nine Months Ended September 30, 2017 and 2016

	Electric and Natural Gas Deliveries				Revenue (in millions)		
	2017	2016	% Change	Weather - Normal % Change	2017	2016	% Change
Electric (in GWhs)							
Retail Deliveries and Sales (a)							
Residential	3,843	4,066	(5.5)%	0.4 %	$ 508	$ 522	(2.7)%
Small Commercial & Industrial	1,693	1,746	(3.0)%	(0.9)%	138	143	(3.5)%
Large Commercial & Industrial	3,440	3,492	(1.5)%	0.3 %	77	74	4.1 %
Public Authorities & Electric Railroads	35	35	— %	— %	11	9	22.2 %
Total Retail	9,011	9,339	(3.5)%	0.1 %	734	748	(1.9)%
Other Revenue (b)					132	124	6.5 %
Total Electric Revenue (c)					866	872	(0.7)%
Natural Gas (in mmcfs)							
Retail Deliveries and Sales (d)							
Retail Sales	8,679	9,253	(6.2)%	6.5 %	87	87	— %
Transportation and Other (e)	4,690	4,455	5.3 %	7.9 %	18	15	20.0 %
Total Natural Gas	13,369	13,708	(2.5)%	7.0 %	105	102	2.9 %
Total Electric and Natural Gas Revenues					$ 971	$ 974	(0.3)%
Purchased Power and Fuel					$ 399	$ 448	(10.9)%

Electric Service Territory				% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	From 2016	From Normal
Heating Degree-Days	2,384	2,812	2,933	(15.2)%	(18.7)%
Cooling Degree-Days	1,228	1,410	1,184	(12.9)%	3.7 %

Gas Service Territory				% Change	
Heating Degree-Days	2017	2016	Normal	From 2016	From Normal
Heating Degree-Days	2,431	2,913	3,062	(16.5)%	(20.6)%

Number of Electric Customers	2017	2016	Number of Natural Gas Customers	2017	2016
Residential	458,790	455,640	Residential	121,238	120,075
Small Commercial & Industrial	60,542	60,034	Commercial & Industrial	9,700	9,656
Large Commercial & Industrial	1,406	1,414	Total Retail	130,938	129,731
Public Authorities & Electric Railroads	633	643	Transportation	155	157
Total	521,371	517,731	Total	131,093	129,888

(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 September 30, 2017 and 2016, respectively, and $6 million and $6 million for the nine months ended September 30, 2017 and 2016, respectively.

(d) 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.

(e) 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.

EXELON CORPORATION
ACE Statistics
Three Months Ended September 30, 2017 and 2016

	Electric Deliveries				Revenue (in millions)		
	2017	2016	% Change	Weather - Normal % Change	2017	2016	% Change
Electric (in GWhs)							
Retail Deliveries and Sales (a)							
Residential	1,349	1,575	(14.3)%	(10.4)%	$ 211	$ 249	(15.3)%
Small Commercial & Industrial	407	426	(4.5)%	(1.9)%	53	55	(3.6)%
Large Commercial & Industrial	939	1,032	(9.0)%	(6.3)%	49	57	(14.0)%
Public Authorities & Electric Railroads	9	11	(18.2)%	(18.2)%	3	4	(25.0)%
Total Retail	2,704	3,044	(11.2)%	(7.8)%	316	365	(13.4)%
Other Revenue (b)					54	56	(3.6)%
Total Electric Revenue (c)					370	421	(12.1)%
Purchased Power					$ 176	$ 221	(20.4)%

				% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	From 2016	From Normal
Heating Degree-Days	23	17	42	35.3 %	(45.2)%
Cooling Degree-Days	830	1,006	806	(17.5)%	3.0 %

Nine Months Ended September 30, 2017 and 2016

	Electric Deliveries				Revenue (in millions)		
	2017	2016	% Change	Weather - Normal % Change	2017	2016	% Change
Electric (in GWhs)							
Retail Deliveries and Sales (a)							
Residential	3,042	3,327	(8.6)%	(6.0)%	$ 484	$ 530	(8.7)%
Small Commercial & Industrial	992	998	(0.6)%	0.8 %	129	133	(3.0)%
Large Commercial & Industrial	2,557	2,705	(5.5)%	(4.6)%	143	158	(9.5)%
Public Authorities & Electric Railroads	33	35	(5.7)%	(5.7)%	10	10	— %
Total Retail	6,624	7,065	(6.2)%	(4.5)%	766	831	(7.8)%
Other Revenue (b)					149	151	(1.3)%
Total Electric Revenue (c)					915	982	(6.8)%
Purchased Power					$ 442	$ 520	(15.0)%

				% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	From 2016	From Normal
Heating Degree-Days	2,608	2,938	3,103	(11.2)%	(16.0)%
Cooling Degree-Days	1,153	1,267	1,092	(9.0)%	5.6 %

Number of Electric Customers	2017	2016
Residential	486,212	483,542
Small Commercial & Industrial	60,982	60,875
Large Commercial & Industrial	3,726	3,796
Public Authorities & Electric Railroads	633	593
Total	551,553	548,806

(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 $0 million and $1 million for the three months ended September 30, 2017 and 2016, respectively, and $2 million and $3 million for the nine months ended September 30, 2017 and 2016, respectively.

Earnings Conference Call
Third Quarter 2017

November 2, 2017

Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2016 Annual Report on 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 24, Commitments and Contingencies; (2) Exelon's Third Quarter 2017 Quarterly Report on Form 10-Q (to be filed on November 2, 2017) in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (2) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this press release. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

Non-GAAP Financial Measures

Exelon reports its financial results in accordance with accounting principles generally accepted in the United States (GAAP). Exelon supplements the reporting of financial information determined in accordance with GAAP with certain non-GAAP financial measures, including:

- ***Adjusted operating earnings*** exclude certain costs, expenses, gains and losses and other specified items, including mark-to-market adjustments from economic hedging activities, unrealized gains and losses from nuclear decommissioning trust fund investments, merger and integration related costs, impairments of certain long-lived assets, certain amounts associated with plant retirements and divestitures, costs related to a cost management program and other items as set forth in the reconciliation in the Appendix
- ***Adjusted operating and maintenance expense*** excludes regulatory operating and maintenance costs for the utility businesses and direct cost of sales for certain Constellation and Power businesses, decommissioning costs that do not affect profit and loss, the impact from operating and maintenance expense related to variable interest entities at Generation, EDF's ownership of O&M expenses, and other items as set forth in the reconciliation in the Appendix
- ***Total gross margin*** is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, JExel Nuclear JV, variable interest entities, and net of direct cost of sales for certain Constellation and Power businesses
- ***Adjusted cash flow from operations*** primarily includes net cash flows from operating activities and net cash flows from investing activities excluding capital expenditures, net merger and acquisitions, and equity investments
- ***Free cash flow*** primarily includes net cash flows from operating activities and net cash flows from investing activities excluding certain capital expenditures, net merger and acquisitions, and equity investments
- ***Operating ROE*** is calculated using operating net income divided by average equity for the period. The operating income reflects all lines of business for the utility business (Electric Distribution, Gas Distribution, Transmission).
- ***EBITDA*** is defined as earnings before interest, taxes, depreciation and amortization. Includes nuclear fuel amortization expense.
- ***Revenue net of purchased power and fuel expense*** is calculated as the GAAP measure of operating revenue less the GAAP measure of purchased power and fuel expense

Due to the forward-looking nature of some forecasted non-GAAP measures, information to reconcile the forecasted adjusted (non-GAAP) measures to the most directly comparable GAAP measure may not be currently available, as management is unable to project all of these items for future periods

Non-GAAP Financial Measures Continued

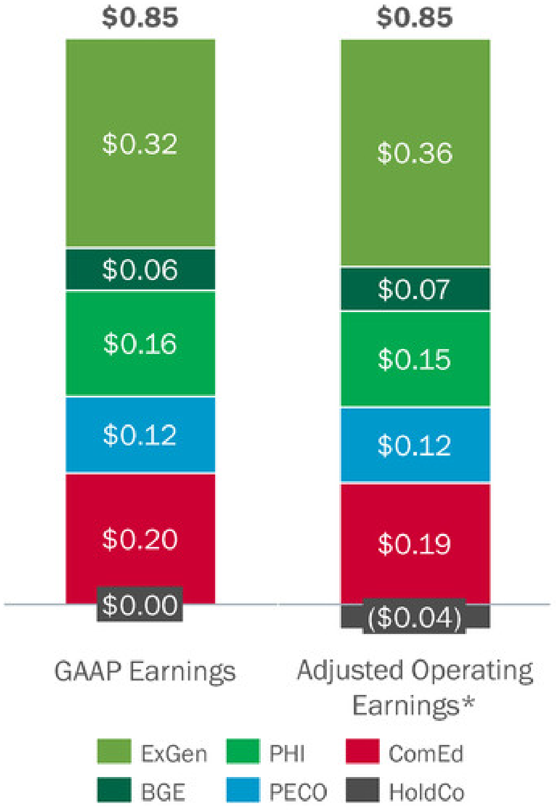
This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of Exelon's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods.

These non-GAAP financial measures are not a presentation defined under GAAP and may not be comparable to other companies' presentation. Exelon has provided these non-GAAP financial measures as supplemental information and in addition to the financial measures that are calculated and presented in accordance with GAAP. These non-GAAP measures should not be deemed more useful than, a substitute for, or an alternative to the most comparable GAAP measures provided in the materials presented.

Non-GAAP financial measures are identified by the phrase "non-GAAP" or an asterisk. Reconciliations of these non-GAAP measures to the most comparable GAAP measures are provided in the appendices and attachments to this presentation, except for the reconciliation for total gross margin, which appears on slide 34 of this presentation.

Strong Third Quarter Results

Q3 2017 EPS Results



- GAAP earnings were $0.85/share in Q3 2017 vs. $0.53/share in Q3 2016
- Adjusted operating earnings* were $0.85/share in Q3 2017 vs. $0.91/share in Q3 2016, at the mid-point of our guidance range of $0.80-$0.90/share

Note: Amounts may not sum due to rounding
* Refer to pages 3 and 4 for information regarding non-GAAP financial measures

Operating Highlights

Exelon Utilities Operational Metrics

Operations	Metric	Q3 2017 BGE	Q3 2017 ComEd	Q3 2017 PECO	Q3 2017 PHI
Electric Operations	OSHA Recordable Rate				
	2.5 Beta SAIFI (Outage Frequency)(1)				
	2.5 Beta CAIDI (Outage Duration)				
Customer Operations	Customer Satisfaction				
	Service Level % of Calls Answered in <30 sec				
	Abandon Rate				
Gas Operations	Percent of Calls Responded to in <1 Hour		No Gas Operations		

- BGE and ComEd are meeting 1st decile performance in CAIDI
- BGE, ComEd and PECO are on track for 1st decile performance in SAIFI
- ComEd and PHI are meeting 1st decile performance in Service Level

Exelon Generation Operational Metrics

- Continued best in class performance across our Nuclear fleet:
  - Q3 Nuclear Capacity Factor: 96.1%(2)
  - Owned and operated Q3 production of 41 TWh was best on record
- Strong performance across our Fossil and Renewable fleet:
  - Q3 Renewables energy capture: 95.9%
  - Q3 Power dispatch match: 98.4%

(1) 2.5 Beta SAIFI is YE projection
(2) Excludes Salem

Q1	Q2
Q3	Q4

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Resiliency and Energy Market Reform

Price Formation

- PJM has stated that it is prepared to implement its reforms allowing all resources to set LMP by mid-2018
- "FERC should expedite its efforts with states, RTO/ISOs, and other stakeholders to improve energy price formation in centrally-organized wholesale electricity markets." – DOE Staff Report, August 2017
- The Commission should focus "first and foremost on the optimization of price formation in the energy and ancillary service markets." Ill. Commerce Comm'n Comments at 7
- "PJM staff is proposing to reform the existing pricing model in order to ensure that the cost of serving load is reflected in LMP to the fullest extent possible... This follows the principles of sound market design." - William W. Hogan, October 23, 2017

Resiliency

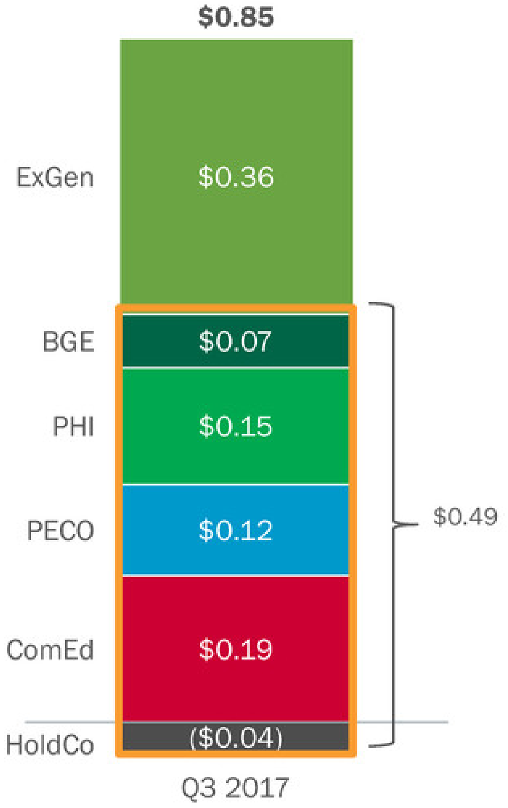
- "Accurately valuing resilience is not a zero-sum game. Compensating base-load generation does not equate to destruction of markets. On the contrary, I think it's a step toward accurately pricing contributions of all market participants." – FERC Chairman Neil Chatterjee, October 13, 2017
- "The unknowns are what we're going to have to deal with: if there was a physical attack, if you had [an explosion like the one on the Spectra pipeline that wasn't] fixed in a timely manner heading into the winter heating season, central Pennsylvania would have had potential issues. . . So now the conversation's gotten broader around these cascading events, and then how do you price resiliency? That conversation needs to take place." FERC Commissioner Rob Powelson, October 27, 2017
- "We used to talk about equipment failure and outages caused by storms. Now, the threat profile has changed, the considerations are broader. There could be intentional attacks – cyber or physical. Those concerns lead us beyond reliability and into resilience." PJM CEO and President Andrew L. Ott, September 20, 2017

Exelon recommends that FERC:

1. Immediately require PJM to submit its energy price formation proposal
2. Require the affected RTOs to submit detailed information on the grid's vulnerabilities to enable the development of a design basis threat analysis that can inform cost-effective market reforms, and
3. State that it will not interfere with state programs that value resilient resources like nuclear plants

Third Quarter Adjusted Operating Earnings* Drivers

Q3 2017 Adjusted Operating EPS* Results



Q3 2017 vs. Guidance of $0.80 - $0.90

Exelon Utilities

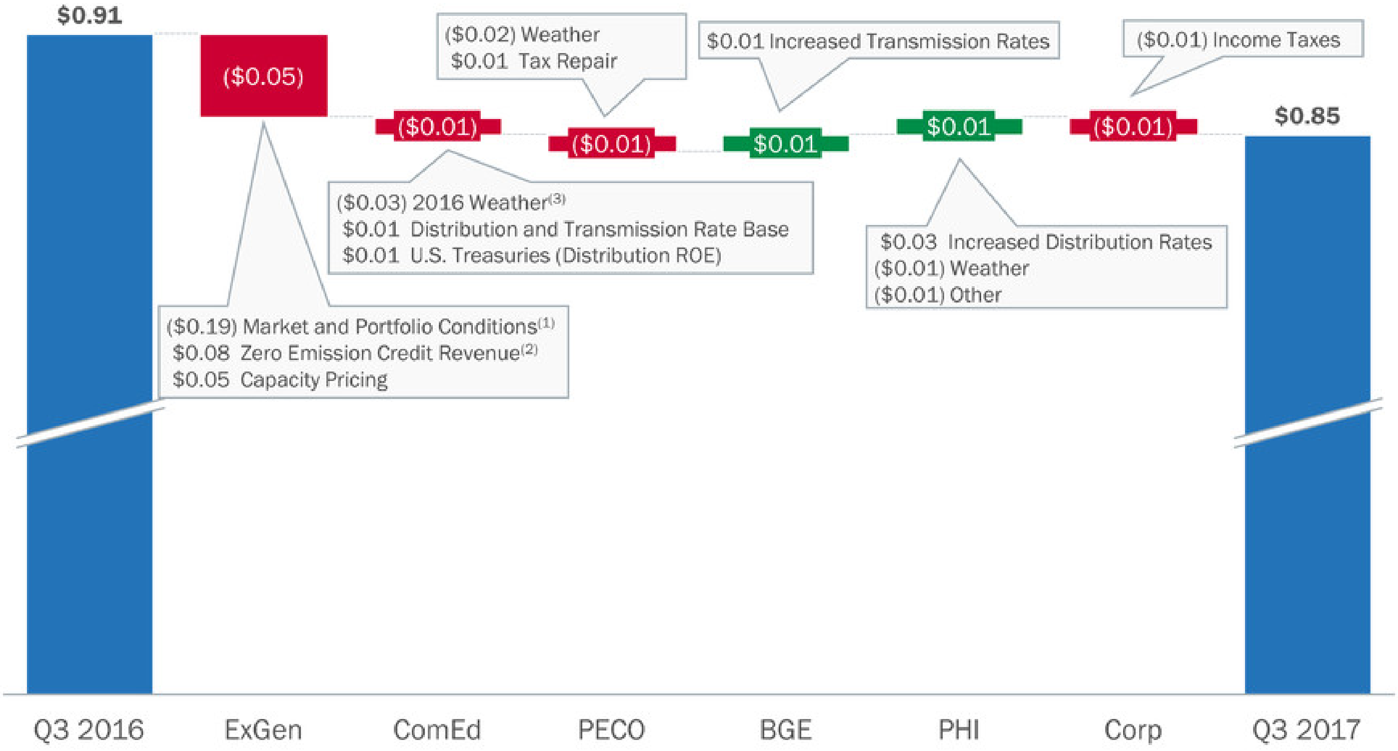
- ↑ Reduced storm activity
- ↑ Lower O&M

Exelon Generation

- ↓ Constellation Gross Margin
- ↑ Timing of O&M

Note: Amounts may not sum due to rounding

QTD Adjusted Operating Earnings* Waterfall



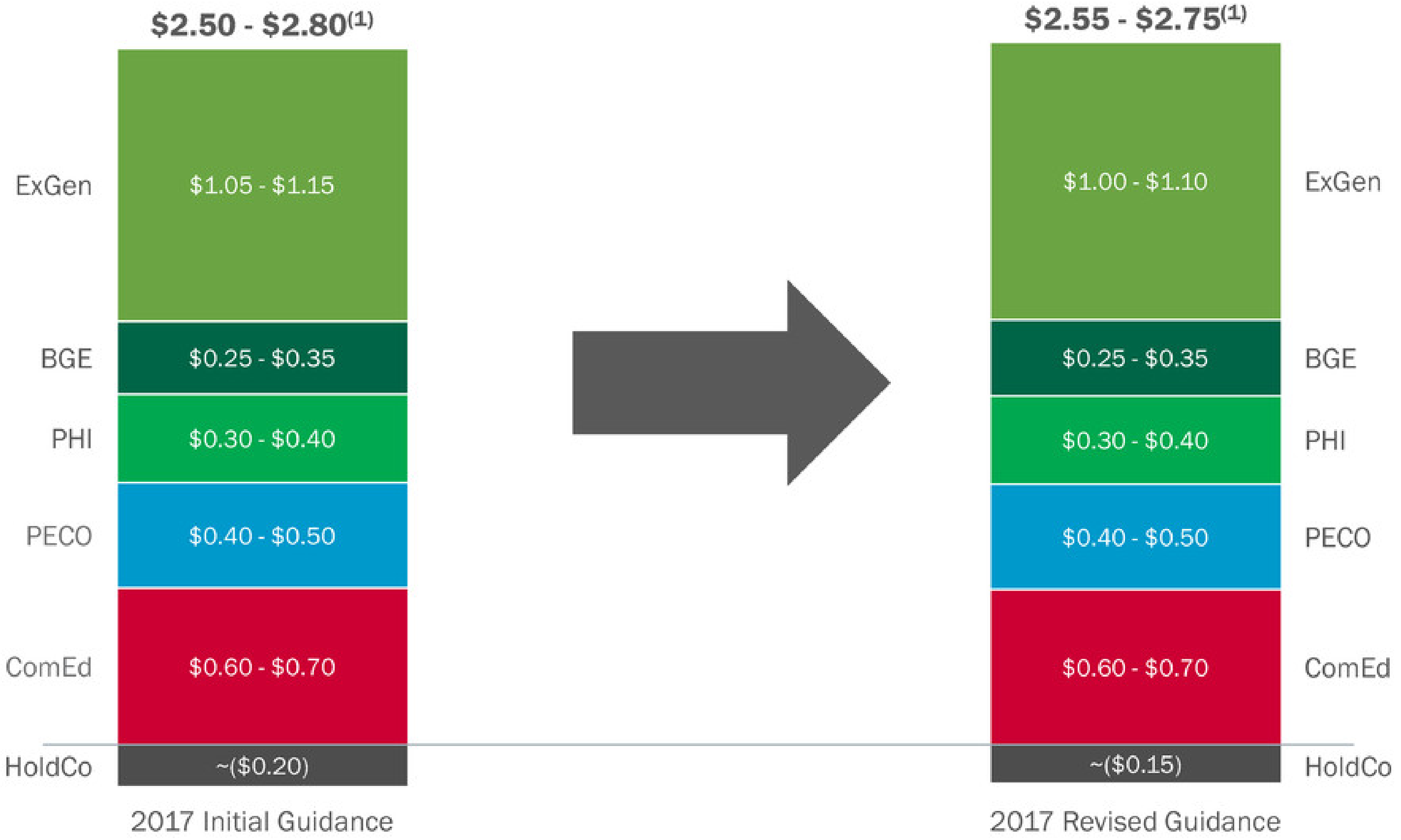
Note: Amounts may not sum due to rounding

(1) Includes the unfavorable impacts of lower load volumes delivered due to mild weather and lower realized energy prices related to Exelon's ratable hedging strategy

(2) Reflects the impact of the New York Clean Energy Standard

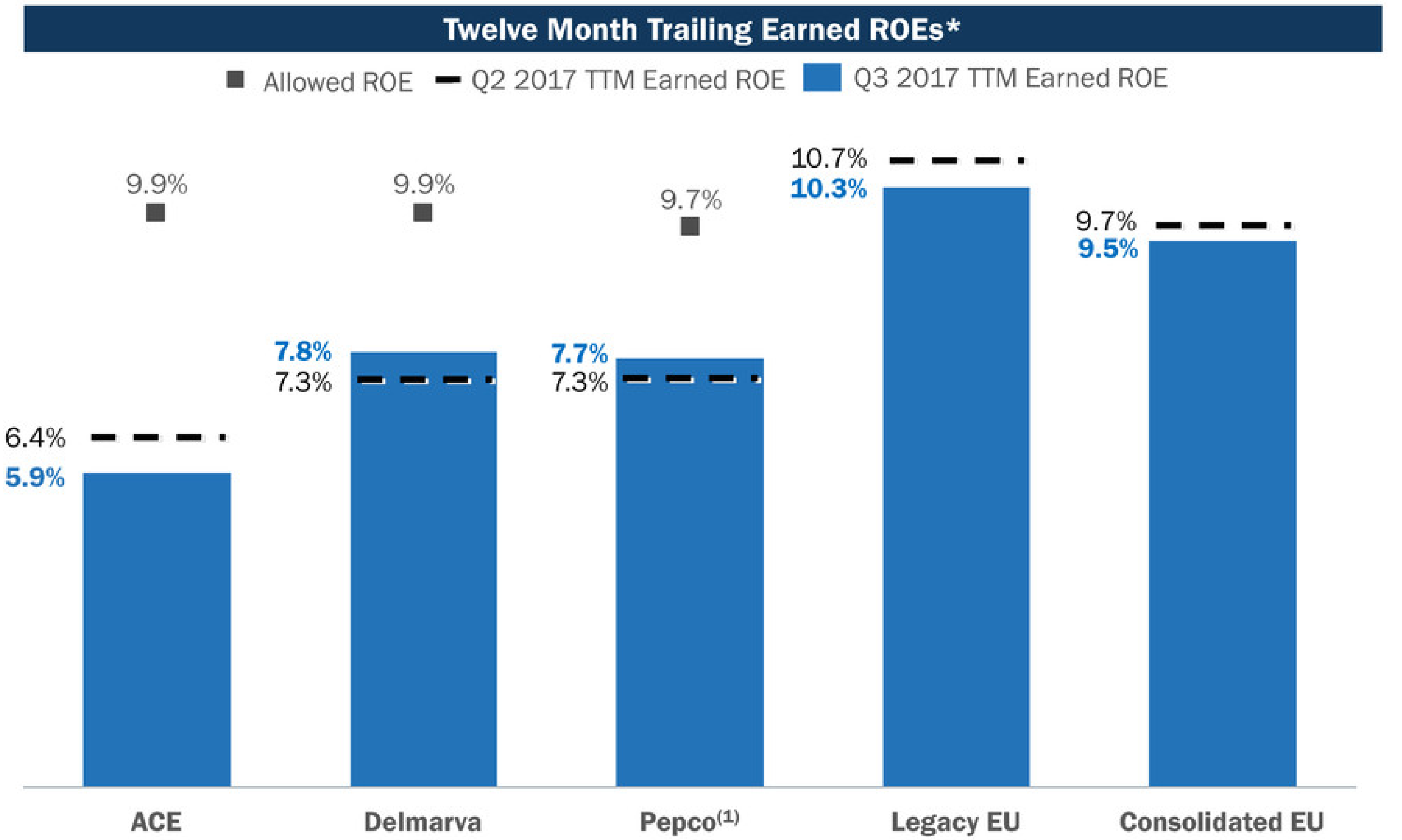
(3) Pursuant to the Illinois Future Energy Jobs Act, beginning in 2017, customer rates for ComEd are adjusted to eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution volumes

Narrowing 2017 Adjusted Operating Earnings* Guidance Range



(1) 2017 earnings guidance based on expected average outstanding shares of 949M. Earnings guidance for OpCos may not sum up to consolidated EPS guidance.
(2) Revised guidance reflects delay in Illinois ZEC revenue recognition for 2017 until 2018, shifting $0.09 of EPS

Trailing 12 Month ROE vs Allowed ROE



Note: Represents the period from 10/1/2016 to 9/30/2017. ROEs represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Transmission).

(1) Pepco MD Distribution allowed ROE is based on authorized ROE of 9.55% for the rates that were in effect during the trailing twelve month period. The order issued on 10/20/17 authorized an ROE of 9.50%.

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Exelon Utilities' Distribution Rate Case Updates

Pepco DC Order	
Authorized Revenue Requirement Increase[1]	$36.9M
Authorized ROE	9.50%
Common Equity Ratio	49.14%
Order Received	7/25/17

ACE NJ Order	
Authorized Revenue Requirement Increase[1]	$43.0M
Authorized ROE	9.60%
Common Equity Ratio	50.47%
Order Received	9/22/17

Pepco MD Order	
Authorized Revenue Requirement Increase[1]	$32.4M
Authorized ROE	9.50%
Common Equity Ratio	50.15%
Order Received	10/20/17

ComEd Filing	
Requested Revenue Requirement Increase[1]	$95.6M[2]
Requested ROE	8.40%
Requested Common Equity Ratio	45.89%
Order Expected	Q4 2017

Delmarva MD Filing	
Requested Revenue Requirement Increase[1]	$21.6M[4]
Requested ROE	10.10%
Requested Common Equity Ratio	50.68%
Order Expected	2/14/18

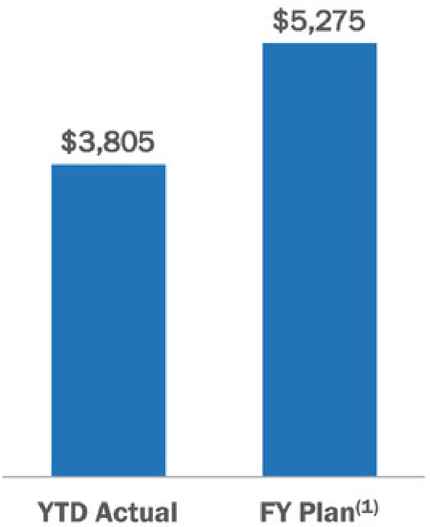
Delmarva DE Electric Filing	
Requested Revenue Requirement Increase[1,3]	$31.2M
Requested ROE	10.10%
Requested Common Equity Ratio	50.52%
Order Expected	Q3 2018

Delmarva DE Gas Filing	
Requested Revenue Requirement Increase[1,3]	$12.9M
Requested ROE	10.10%
Requested Common Equity Ratio	50.52%
Order Expected	Q3 2018

(1) Revenue requirement includes changes in depreciation and amortization expense where applicable, which have no impact on pre-tax earnings
(2) Amount represents ComEd's position filed in Rebuttal testimony on July 21, 2017
(3) As permitted by Delaware law, Delmarva Power will implement interim rate increases of $2.5M in Q3 2017 and will implement full allowable rates on March 17, 2018, subject to refund
(4) Amount represents adjusted requested revenue requirement filed on September 28, 2017

Utility CapEx Update

2017 Exelon Utilities CapEx Spend ($M)



Notable Projects

- **Pepco's Waterfront Substation**
  - $182 million invested to date. Expected completion by end of 2017
  - Part of "Capital Grid" project
  - Replaces aging infrastructure and improves substation performance
  - Will support existing customers and planned development in the Capitol Riverfront and Southwest Waterfront areas
- **ComEd's Grand Prairie Gateway transmission line**
  - $203 million investment
  - 60-mile, 345kV line through four northern Illinois counties
  - Energized April 2017
  - Estimated customer savings of $121 to $325 million, net of construct costs, within the first 15 years
  - Reduces carbon emissions by nearly 500,000 tons within the first 15 years

Exelon Utilities on track to meet their 2017 capital investment commitments to the benefit of customers

(1) FY Plan rounded to the nearest $25M

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Exelon Generation: Gross Margin Update

	September 30, 2017			Change from June 30, 2017		
Gross Margin Category ($M)(1)	**2017**	**2018**	**2019**	**2017**	**2018**	**2019**
Open Gross Margin(2,5) (including South, West, Canada hedged gross margin)	$3,600	$3,900	$3,700	$(150)	$(100)	$(100)
Capacity and ZEC Revenues(2,5,6)	$1,700	$2,300	$2,000	$(150)	$100	$(50)
Mark-to-Market of Hedges(2,3)	$2,150	$650	$450	$250	$100	$50
Power New Business / To Go	$100	$700	$850	$(100)	$(150)	$(100)
Non-Power Margins Executed	$350	$200	$100	$50	$50	-
Non-Power New Business / To Go	$100	$300	$400	$(50)	$(50)	-
Total Gross Margin*(4,5)	**$8,000**	**$8,050**	**$7,500**	**$(150)**	**$(50)**	**$(200)**

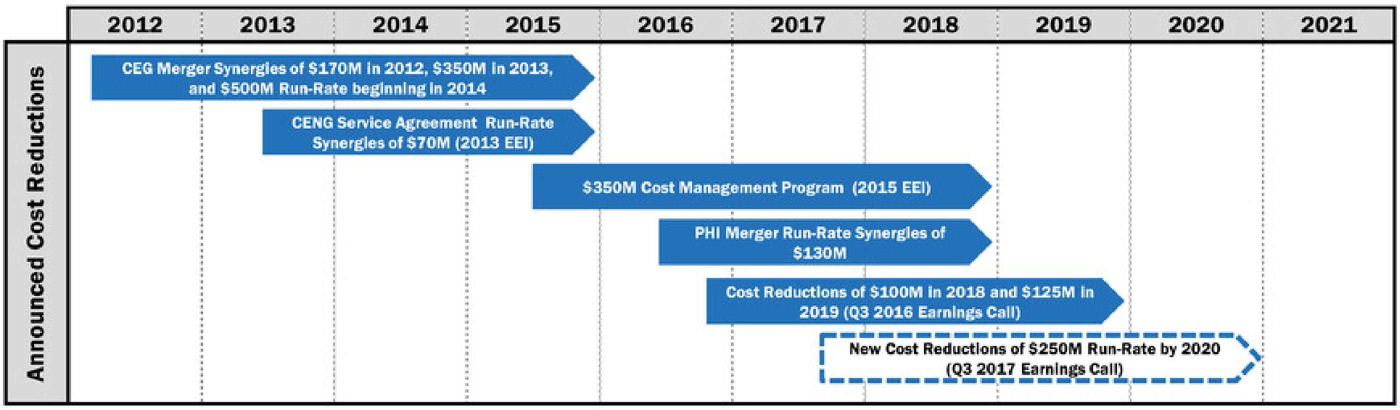
Recent Developments

- Delay in recognition of Illinois ZEC revenues lowers the Capacity and ZEC Revenues line in 2017 by $150M and increases the 2018 line by $150M – see slide 21 for details
- Excluding impact of Illinois ZEC timing:
  - In 2017, $50M reduction in Power New Business targets
  - In both 2018 and 2019, $100M reduction due to lower power and capacity prices and $100M reduction to Power New Business Targets
- Behind ratable hedging position reflects the upside we see in power prices
  - ~11-14% behind ratable in 2018 when considering cross commodity hedges

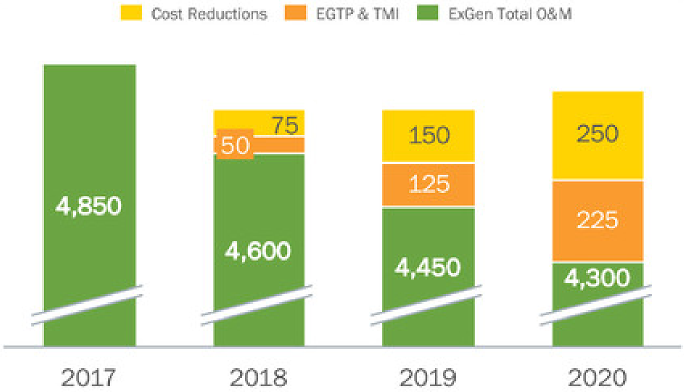
(1) Gross margin categories rounded to nearest $50M
(2) Excludes EDF's equity ownership share of the CENG Joint Venture
(3) Mark-to-Market of Hedges assumes mid-point of hedge percentages
(4) Based on September 30, 2017, market conditions
(5) Reflects TMI and Oyster Creek retirements in September 2019 and December 2019, respectively. EGTP removal impacts partial year 2017 and full year 2018 and 2019.
(6) 2018 includes $150M of IL ZEC revenues associated with 2017 production

Cost Management is Integral to Our Business Strategy

ExGen and BSC Cost Reductions Since Constellation Merger



ExGen Forecast O&M* Q3 2017 ($M)(1)

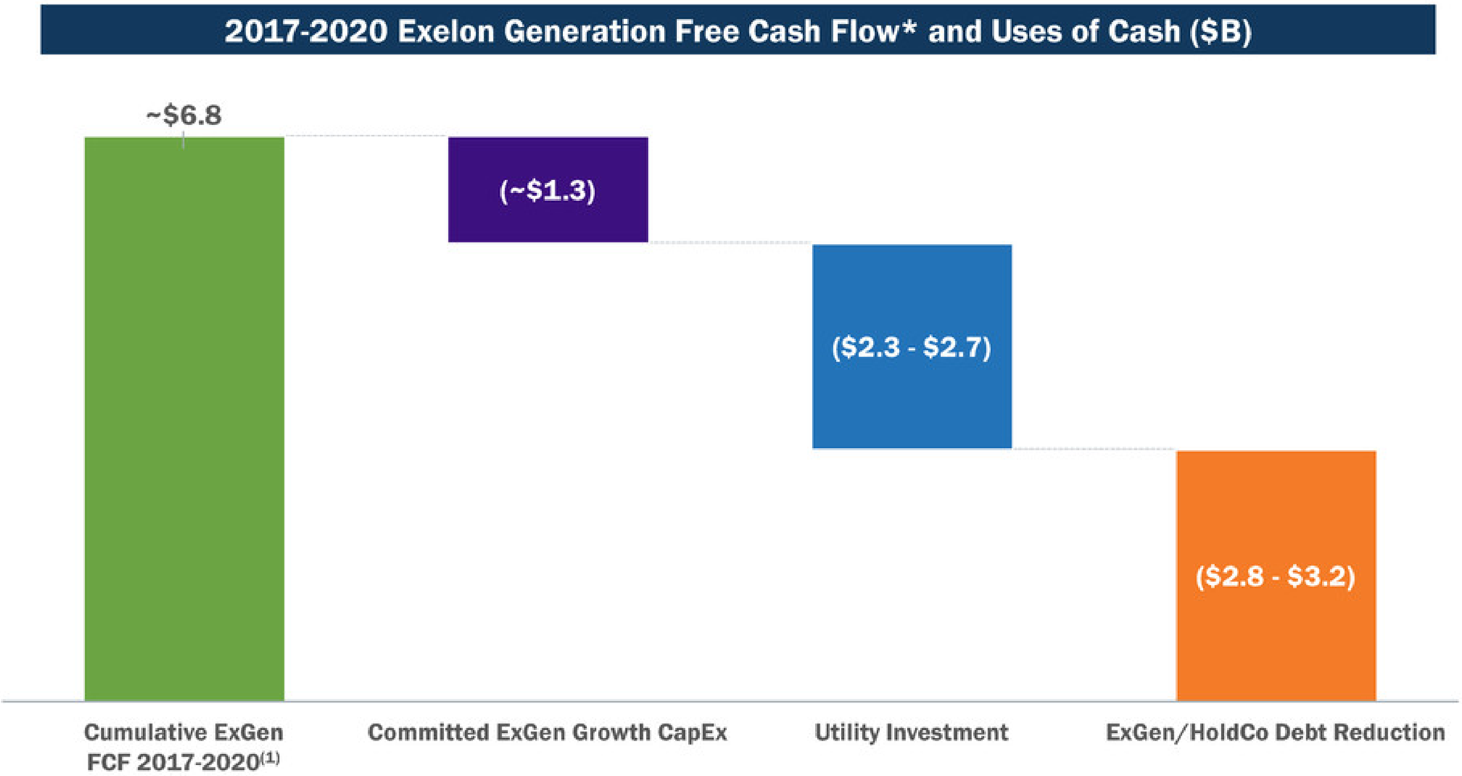


(1) Adjusted for TMI retirement and removal of EGTP, net of other expenses

ExGen Forecast O&M*: Q3 2017 vs. Q4 2016(1)

ExGen O&M ($M)	2017	2018	2019	2020	2017-2020 CAGR
Q4 2016 O&M	$4,850	$4,725	$4,725	$4,775	- 0.5%
EGTP & TMI	($0)	($50)	($125)	($225)	-
Q4 '16 O&M, Net of EGTP & TMI	**$4,850**	**$4,675**	**$4,600**	**$4,550**	**-2.1%**
Cost Savings	($0)	($75)	($150)	($250)	-
Q3 2017 O&M	**$4,850**	**$4,600**	**$4,450**	**$4,300**	**-3.9%**

ExGen's Strong Free Cash Flow Supports Utility Growth and Debt Reduction

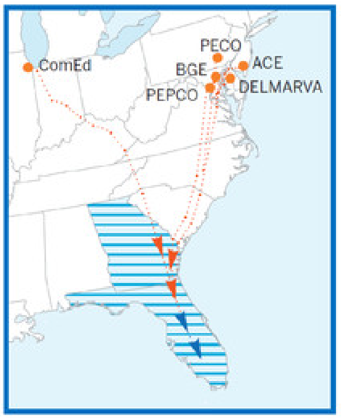


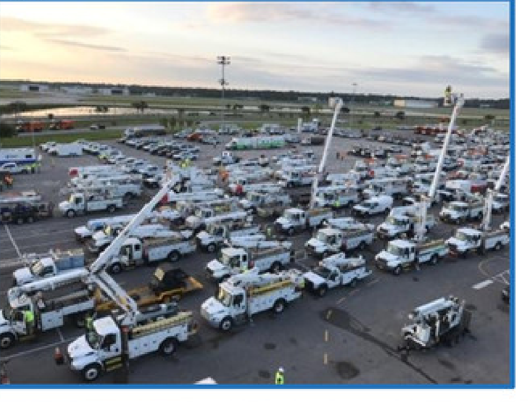
Redeploying Exelon Generation's free cash flow to maximize shareholder value

(1) Sources include change in margin, tax parent benefit, equity investments, and acquisitions and divestitures

Hurricane Support

- More than 2,200 employees, contractors and support personnel from Exelon's six utilities mobilized to assist residents in the southeastern U.S. impacted by Hurricane Irma
  - Exelon teams shared our experience with severe weather restoration efforts and industry-leading best practices to lead one of the largest contingents of support nationally
  - Crews deployed for more than two weeks helping to restore power to nearly eight million customers in Florida and Georgia
- Approximately 250 Exelon employee volunteers logged over 1,300 hours for disaster relief activities
- Exelon and its employees contributed approximately $820,000 in disaster relief





The Exelon Value Proposition

- **Regulated Utility Growth** with utility EPS rising 6-8% annually from 2017-2020 and rate base growth of 6.5%, representing an expanding majority of earnings
- **ExGen's strong free cash generation** will support utility growth while also reducing debt by ~$3B over the next 4 years
- **Optimizing ExGen value by:**
  - Seeking fair compensation for the zero-carbon attributes of our fleet;
  - Closing uneconomic plants;
  - Monetizing assets; and
  - Maximizing the value of the fleet through our generation to load matching strategy
- **Strong balance sheet is a priority** with all businesses comfortably meeting investment grade credit metrics through the 2020 planning horizon
- **Capital allocation priorities targeting:**
  - Organic utility growth;
  - Return of capital to shareholders with 2.5% annual dividend growth through 2018[1],
  - Debt reduction; and
  - Modest contracted generation investments

(1) Quarterly dividends are subject to declaration by the board of directors

Additional Disclosures

2017 Projected Sources and Uses of Cash

($M)[1]	BGE	ComEd	PECO	PHI	Total Utilities	ExGen	Corp[8]	Exelon 2017E	Cash Balance
Beginning Cash Balance*[2]									**1,050**
Adjusted Cash Flow from Operations*[2]	775	1,025	750	1,175	3,750	3,350	75	7,150	
Base CapEx and Nuclear Fuel[3]	0	0	0	0	0	(1,950)	(50)	(2,025)	
Free Cash Flow*	**775**	**1,025**	**750**	**1,175**	**3,750**	**1,375**	**0**	**5,125**	
Debt Issuances	300	1,000	325	200	1,825	750	1,150	3,725	
Debt Retirements	(300)	(425)	0	(150)	(875)	(700)	(1,700)	(3,275)	
Project Financing	n/a	n/a	n/a	n/a	n/a	275	n/a	275	
Equity Issuance/Share Buyback	0	0	0	0	0	0	1,150	1,150	
Contribution from Parent	175	675	0	800	1,650	0	(1,625)	25	
Other Financing[4]	150	350	150	(375)	275	50	425	725	
Financing*[5]	**350**	**1,600**	**475**	**450**	**2,875**	**350**	**(625)**	**2,625**	
Total Free Cash Flow and Financing	**1,125**	**2,625**	**1,225**	**1,650**	**6,600**	**1,750**	**(600)**	**7,750**	
Utility Investment	(925)	(2,200)	(775)	(1,375)	(5,250)	0	0	(5,250)	
ExGen Growth[3,6]	0	0	0	0	0	(800)	0	(800)	
Acquisitions and Divestitures	0	0	0	0	0	0	0	0	
Equity Investments	0	0	0	0	0	(50)	0	(50)	
Dividend[7]	0	0	0	0	0	0	(1,225)	(1,225)	
Other CapEx and Dividend	**(925)**	**(2,200)**	**(775)**	**(1,375)**	**(5,250)**	**(875)**	**(1,225)**	**(7,350)**	
Total Cash Flow	**200**	**450**	**450**	**250**	**1,350**	**875**	**(1,850)**	**400**	
Ending Cash Balance*[2]									**1,450**

(1) All amounts rounded to the nearest $25M. Figures may not add due to rounding.
(2) Gross of posted counterparty collateral
(3) Figures reflect cash CapEx and CENG fleet at 100%
(4) Other Financing includes primarily expected changes in short-term debt, money pool borrowings, tax sharing from the parent, debt issue costs, CENG borrowing from Sumitomo, tax equity cash flows, capital leases, and renewable JV proceeds
(5) Financing cash flow excludes intercompany dividends and other intercompany financing activities
(6) ExGen Growth CapEx primarily includes Texas CCGTs, AGE, W. Medway, and Retail Solar
(7) Dividends are subject to declaration by the Board of Directors
(8) Includes cash flow activity from Holding Company, eliminations, and other corporate entities

Consistent and reliable free cash flows

Operational excellence and financial discipline drives free cash flow reliability

✓ Generating $5.1B of free cash flow, including $1.4B at ExGen and $3.8B at the Utilities

Supported by a strong balance sheet

Strong balance sheet enables flexibility to raise and deploy capital for growth

✓ $0.9B of long-term debt at the utilities, net of refinancing, to support continued growth

Enable growth & value creation

Creating value for customers, communities and shareholders

✓ Investing $6.1B, with $5.3B at the Utilities and $0.8B at ExGen

Note: Numbers may not add due to rounding

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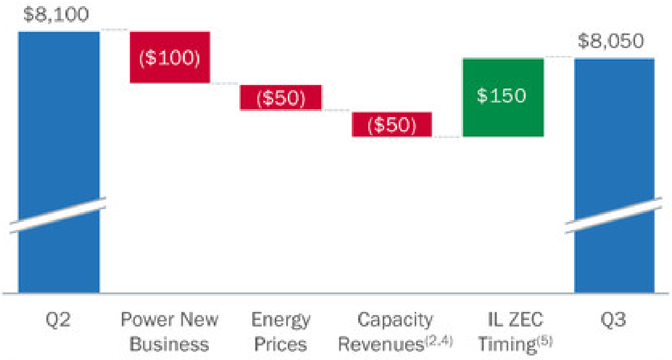
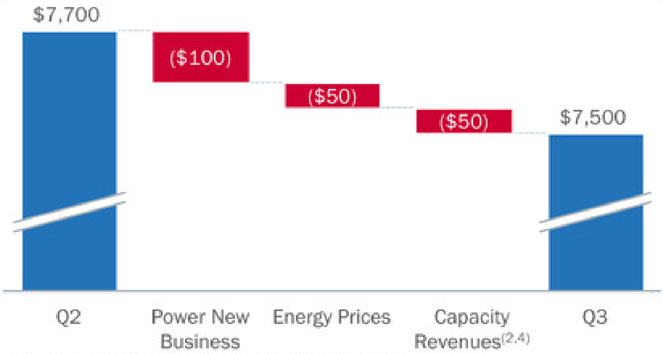
ExGen Forward Total Gross Margin* Walk: Q3 2017 vs. Q2 2017

FY 2017 ($M)(1,3,4)

FY 2018 ($M)(1,3,4)



FY 2019 ($M)(1,3,4)



Key Takeaways

- Change in timing of Illinois ZEC contract finalization results in 2017 reduction of $150M on a rounded basis and 2018 increase of $150M
- Aggressive bidding by market participants in a low volatility period is pressuring Wholesale margins and limiting C&I Retail growth; reduce Power New Business To Go by $100M in 2018 and 2019 to reflect continuation of current, low discipline market bidding behavior
- Lower energy prices reduce Open Gross Margin by $50M in 2018 and 2019; October price recovery offsets 2019 declines
- Lower observed capacity prices in NY and MISO reduce Capacity Revenues by $50M on a rounded basis in 2018 and 2019

(1) Gross margin categories rounded to nearest $50M
(2) Excludes EDF's equity ownership share of the CENG Joint Venture
(3) Based on September 30, 2017, market conditions
(4) Reflects TMI and Oyster Creek retirements in September 2019 and December 2019, respectively
(5) 2018 includes $150M of IL ZEC revenues associated with 2017 production

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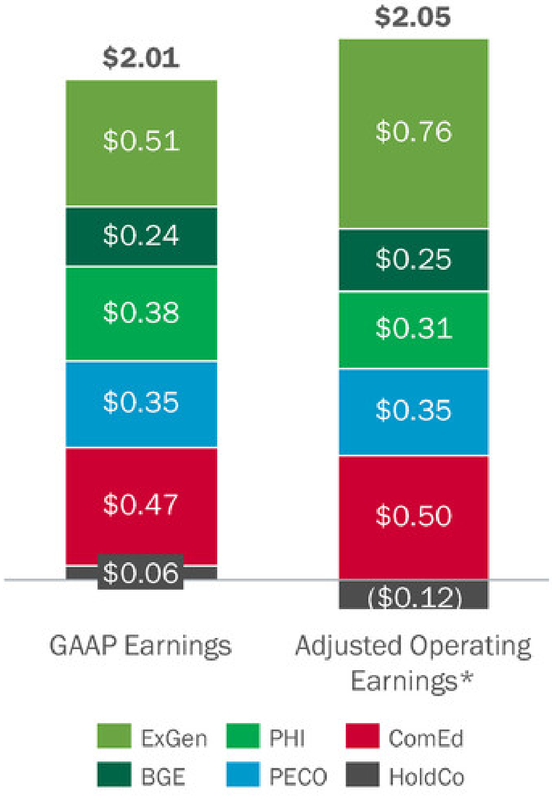
YTD Earnings Results

YTD 2017 EPS Results

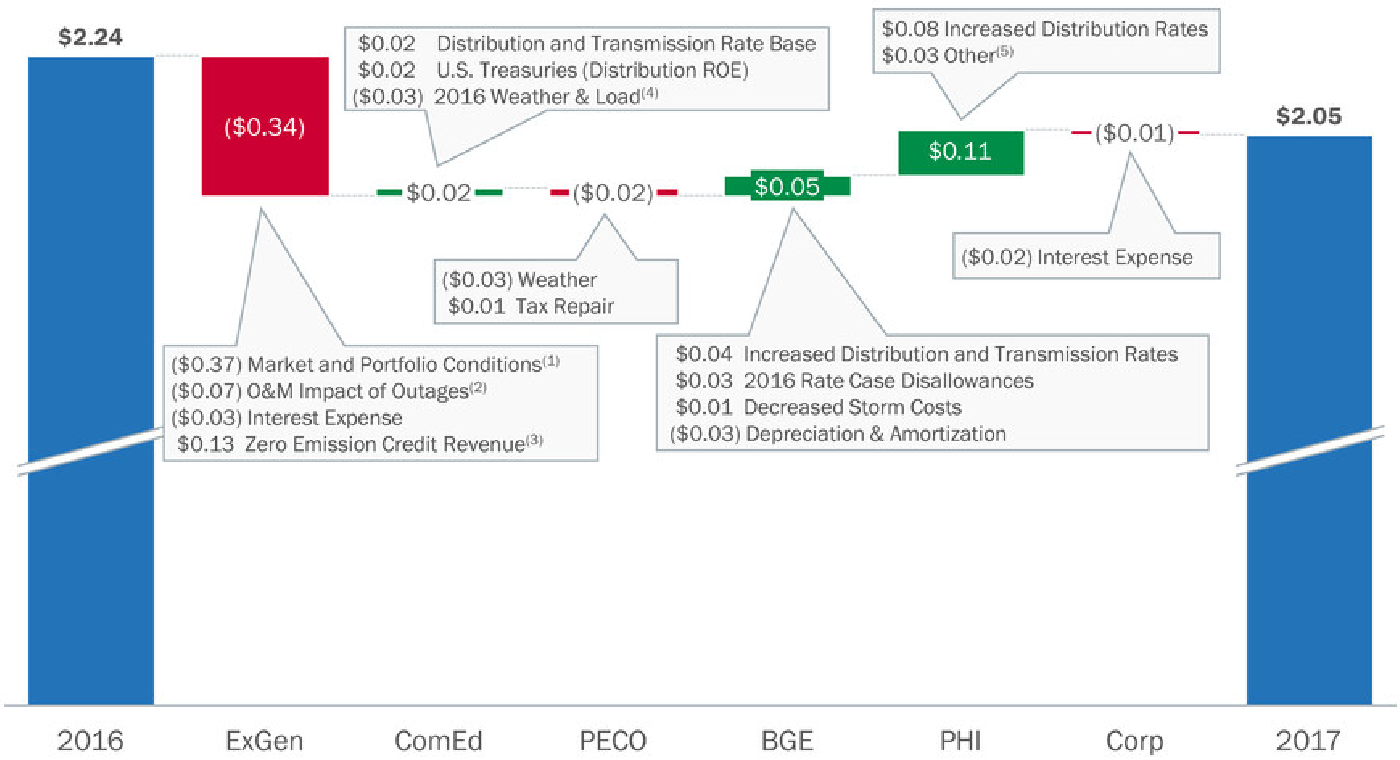


- GAAP earnings were $2.01/share YTD 2017 vs. $1.00/share YTD 2016
- Adjusted operating earnings* were $2.05/share YTD 2017 vs. $2.24/share YTD 2016

Note: Amounts may not sum due to rounding
* Refer to pages 3 and 4 for information regarding non-GAAP financial measures

Exelon.

YTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

(1) Includes the unfavorable impact of the conclusion of the Ginna Reliability Support Services Agreement, the impacts of declining natural gas prices on Generation's natural gas portfolio, the impacts of lower load volumes delivered due to mild weather and lower realized energy prices related to Exelon's ratable hedging strategy

(2) Driven by higher planned nuclear outages in 2017; excludes Salem

(3) Reflects the impact of the New York Clean Energy Standard

(4) Pursuant to the Illinois Future Energy Jobs Act, beginning in 2017, customer rates for ComEd are adjusted to eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution volumes

(5) PHI reflects full nine months of earnings in 2017 versus earnings from March 24, 2016, through September 30, 2016

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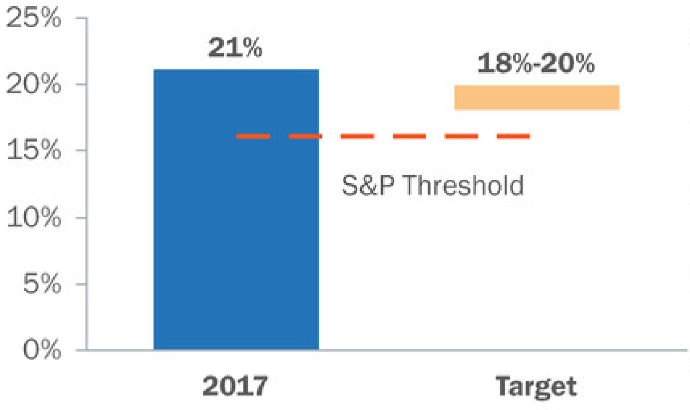
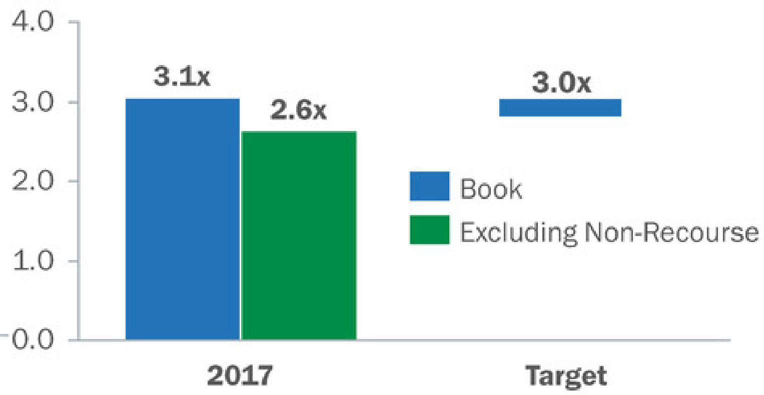
Maintaining Strong Investment Grade Credit Ratings is a Top Financial Priority

Exelon S&P FFO/Debt %*(1,4,6,7)



ExGen Debt/EBITDA Ratio*(5,6,7)

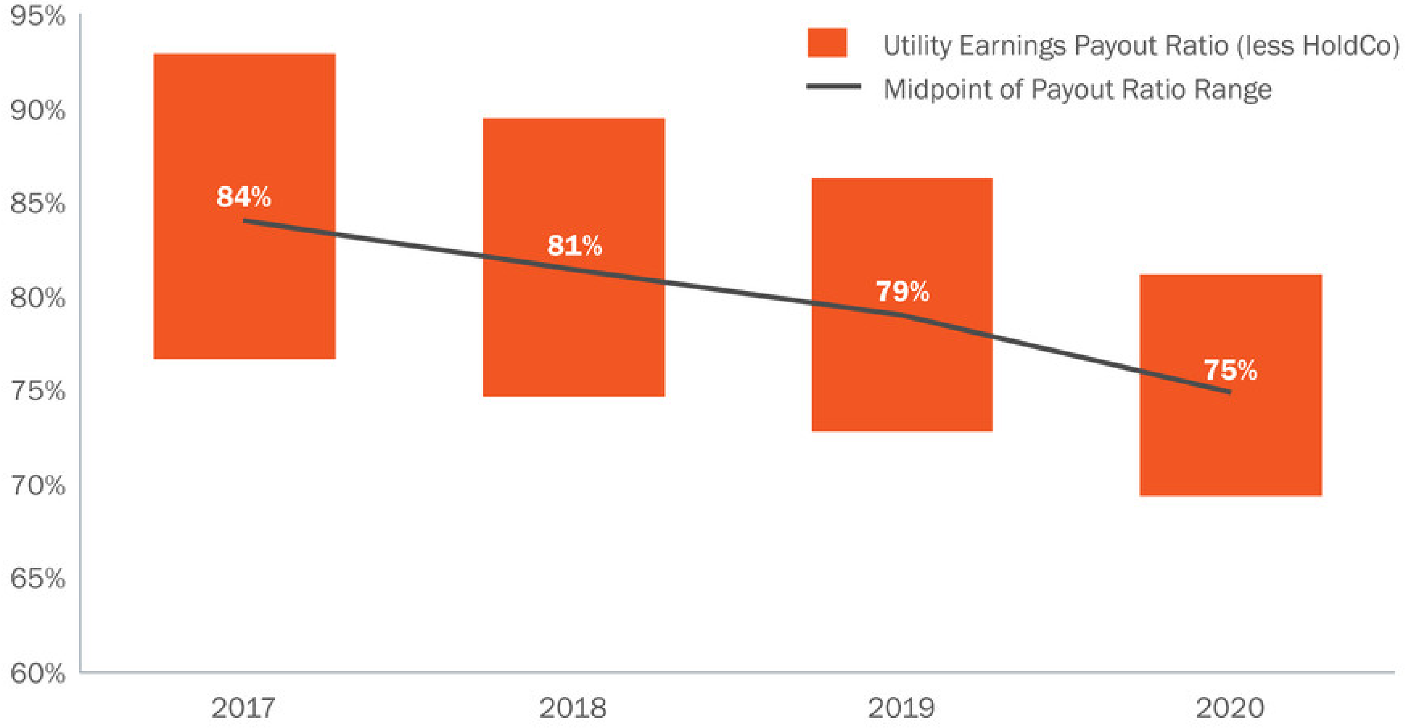


Credit Ratings by Operating Company

Current Ratings(2,3)	ExCorp	ExGen	ComEd	PECO	BGE	ACE	DPL	Pepco
Moody's	Baa2	Baa2	A1	Aa3	A3	A3	A2	A2
S&P	BBB-	BBB	A-	A-	A-	A	A	A
Fitch	BBB	BBB	A	A	A-	A-	A	A-

(1) Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment
(2) Current senior unsecured ratings as of October 24, 2017, for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco
(3) All ratings have a "Stable" outlook
(4) Exelon Corp downgrade threshold (red dotted line) is based on the S&P Exelon Corp Summary Report; represents minimum level to maintain current Issuer Credit Rating of BBB at Exelon Corp
(5) Reflects net book debt (YE debt less cash on hand) / adjusted operating EBITDA*
(6) Reflects removal of EGTP
(7) Reflects delay in Illinois ZEC revenue recognition from 2017 to 2018

Theoretical Dividend Affordability from Utility less HoldCo[1,2]



Utility less HoldCo payout ratio falling consistently even as dividend grows

(1) Chart is illustrative and shows theoretical payout ratio if utilities supported 100% of the external dividend and interest expense at HoldCo. Currently, the utilities have a payout ratio of 70% which covers the majority of the external dividend and interest expense at HoldCo with ExGen covering the remainder.

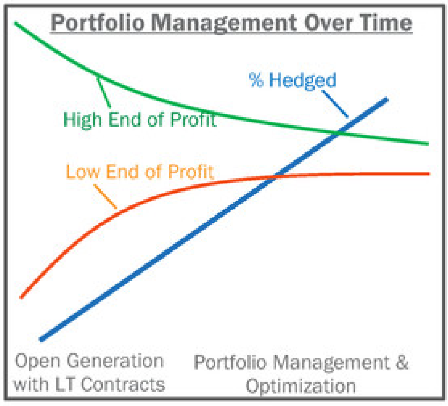
(2) Board of directors has approved a policy of 2.5% per year dividend increase through 2018. For illustrative purposes only, the chart assumes the dividend continues to increase 2.5% per year through 2020, although the board has not yet established dividend policy for periods after 2018. Quarterly dividends are subject to declaration by the board of directors.

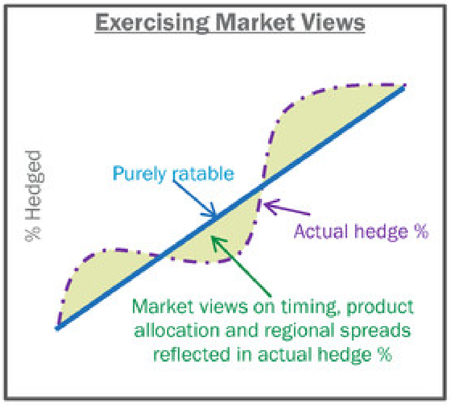
Exelon Generation Disclosures

September 30, 2017

Portfolio Management Strategy

Strategic Policy Alignment	Three-Year Ratable Hedging	Bull / Bear Program
• Aligns hedging program with financial policies and financial outlook • Establish minimum hedge targets to meet financial objectives of the company (dividend, credit rating) • Hedge enough commodity risk to meet future cash requirements under a stress scenario	• Ensure stability in near-term cash flows and earnings • Disciplined approach to hedging • Tenor aligns with customer preferences and market liquidity • Multiple channels to market that allow us to maximize margins • Large open position in outer years to benefit from price upside	• Ability to exercise fundamental market views to create value within the ratable framework • Modified timing of hedges versus purely ratable • Cross-commodity hedging (heat rate positions, options, etc.) • Delivery locations, regional and zonal spread relationships





Protect Balance Sheet | **Ensure Earnings Stability** | **Create Value**

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Components of Gross Margin Categories

Gross margin linked to power production and sales				Gross margin from other business activities	
Open Gross Margin	**Capacity and ZEC Revenues**	**MtM of Hedges[2]**	**"Power" New Business**	**"Non Power" Executed**	**"Non Power" New Business**
• Generation Gross Margin at current market prices, including ancillary revenues, nuclear fuel amortization and fossils fuels expense • Power Purchase Agreement (PPA) Costs and Revenues • Provided at a consolidated level for all regions (includes hedged gross margin for South, West and Canada[1])	• Expected capacity revenues for generation of electricity • Expected revenues from Zero Emissions Credits (ZEC)	• Mark-to-Market (MtM) of power, capacity and ancillary hedges, including cross commodity, retail and wholesale load transactions • Provided directly at a consolidated level for five major regions. Provided indirectly for each of the five major regions via Effective Realized Energy Price (EREP), reference price, hedge %, expected generation.	• Retail, Wholesale planned electric sales • Portfolio Management new business • Mid marketing new business	• Retail, Wholesale executed gas sales • Energy Efficiency[4] • BGE Home[4] • Distributed Solar	• Retail, Wholesale planned gas sales • Energy Efficiency[4] • BGE Home[4] • Distributed Solar • Portfolio Management / origination fuels new business • Proprietary trading[3]

Margins move from new business to MtM of hedges over the course of the year as sales are executed[5]

Margins move from "Non power new business" to "Non power executed" over the course of the year

(1) Hedged gross margins for South, West & Canada region will be included with Open Gross Margin; no expected generation, hedge %, EREP or reference prices provided for this region
(2) MtM of hedges provided directly for the five larger regions; MtM of hedges is not provided directly at the regional level but can be easily estimated using EREP, reference price and hedged MWh
(3) Proprietary trading gross margins will generally remain within "Non Power" New Business category and only move to "Non Power" Executed category upon management discretion
(4) Gross margin for these businesses are net of direct "cost of sales"
(5) Margins for South, West & Canada regions and optimization of fuel and PPA activities captured in Open Gross Margin

ExGen Disclosures

Gross Margin Category ($M)(1)	2017	2018	2019
Open Gross Margin (including South, West & Canada hedged GM)(2,5)	$3,600	$3,900	$3,700
Capacity and ZEC Revenues(2,5,6)	$1,700	$2,300	$2,000
Mark-to-Market of Hedges(2,3)	$2,150	$650	$450
Power New Business / To Go	$100	$700	$850
Non-Power Margins Executed	$350	$200	$100
Non-Power New Business / To Go	$100	$300	$400
Total Gross Margin*(4,5)	**$8,000**	**$8,050**	**$7,500**

Reference Prices(4)	2017	2018	2019
Henry Hub Natural Gas ($/MMBtu)	$3.14	$3.05	$2.89
Midwest: NiHub ATC prices ($/MWh)	$26.52	$27.45	$26.36
Mid-Atlantic: PJM-W ATC prices ($/MWh)	$28.81	$30.77	$29.22
ERCOT-N ATC Spark Spread ($/MWh) *HSC Gas, 7.2HR, $2.50 VOM*	($0.78)	$1.22	$2.65
New York: NY Zone A ($/MWh)	$24.38	$27.29	$26.67
New England: Mass Hub ATC Spark Spread ($/MWh) *ALQN Gas, 7.5HR, $0.50 VOM*	$4.36	$3.99	$4.24

(1) Gross margin categories rounded to nearest $50M
(2) Excludes EDF's equity ownership share of the CENG Joint Venture
(3) Mark-to-Market of Hedges assumes mid-point of hedge percentages
(4) Based on September 30, 2017, market conditions
(5) Reflects ownership of FitzPatrick as of April 1, 2017, and TMI and Oyster Creek retirements in September 2019 and December 2019, respectively. EGTP removal impacts partial year 2017 and full year 2018 and 2019.
(6) 2018 includes $150M of IL ZEC revenues associated with 2017 production

ExGen Disclosures

Generation and Hedges	2017	2018	2019
Exp. Gen (GWh)[1]	**200,200**	**199,300**	**202,000**
Midwest	95,900	95,800	97,000
Mid-Atlantic[2,6]	60,700	60,500	59,000
ERCOT	17,800	19,500	20,800
New York[2,6]	14,700	15,500	16,600
New England	11,100	8,000	8,600
% of Expected Generation Hedged[3]	**98%-101%**	**79%-82%**	**45%-48%**
Midwest	97%-100%	74%-77%	41%-44%
Mid-Atlantic[2,6]	98%-101%	90%-93%	51%-54%
ERCOT	97%-100%	77%-80%	44%-47%
New York[2,6]	99%-102%	71%-74%	43%-46%
New England	103%-106%	86%-89%	52%-55%
Effective Realized Energy Price ($/MWh)[4]			
Midwest	$33.00	$29.50	$29.50
Mid-Atlantic[2,6]	$44.00	$37.00	$39.00
ERCOT[5]	$11.00	$3.50	$3.50
New York[2,6]	$41.50	$37.50	$32.00
New England[5]	$20.00	$2.50	$3.00

(1) 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. Expected generation assumes 15 refueling outages in 2017, 15 in 2018, and 11 in 2019 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 93.4%, 93.2% and 94.7% in 2017, 2018, and 2019, respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2018 and 2019 do not represent guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years.

(2) Excludes EDF's equity ownership share of CENG Joint Venture

(3) Percent of expected generation hedged is the amount of equivalent sales divided by expected generation. Includes all hedging products, such as wholesale and retail sales of power, options and swaps.

(4) Effective realized energy price is representative of an all-in hedged price, on a per MWh basis, at which expected generation has been hedged. It is developed by considering the energy revenues and costs associated with our hedges and by considering the fossil fuel that has been purchased to lock in margin. It excludes uranium costs, RPM capacity and ZEC revenues, but includes the mark-to-market value of capacity contracted at prices other than RPM clearing prices including our load obligations. It can be compared with the reference prices used to calculate open gross margin in order to determine the mark-to-market value of Exelon Generation's energy hedges.

(5) Spark spreads shown for ERCOT and New England

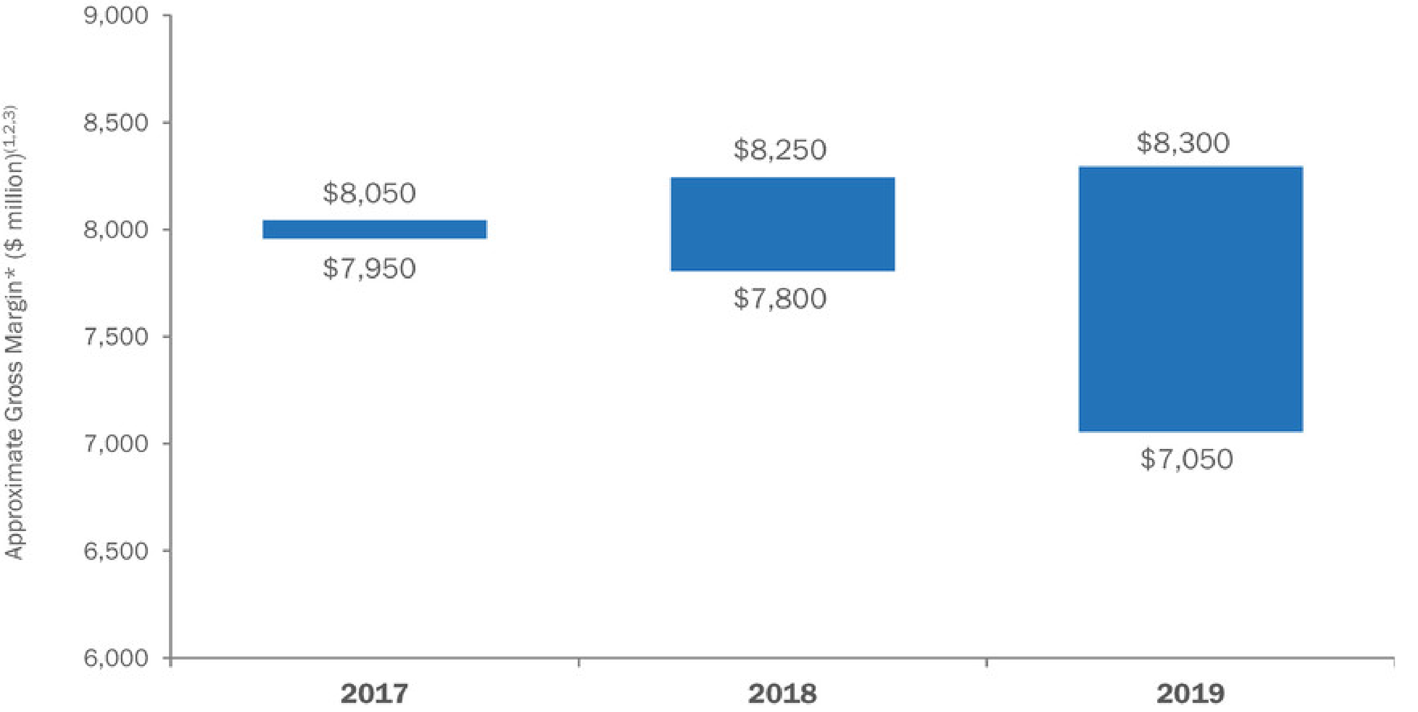
(6) Reflects ownership of FitzPatrick as of April 1, 2017, and TMI and Oyster Creek retirements in September 2019 and December 2019, respectively. EGTP removal impacts partial year 2017 and full year 2018 and 2019.

ExGen Hedged Gross Margin* Sensitivities

Gross Margin* Sensitivities (with existing hedges)(1)	2017	2018	2019
Henry Hub Natural Gas ($/MMBtu)			
+ $1/MMBtu	$(20)	$140	$515
- $1/MMBtu	$(10)	$(210)	$(500)
NiHub ATC Energy Price			
+ $5/MWh	-	$120	$265
- $5/MWh	-	$(115)	$(265)
PJM-W ATC Energy Price			
+ $5/MWh	-	$10	$150
- $5/MWh	$5	$(40)	$(145)
NYPP Zone A ATC Energy Price			
+ $5/MWh	-	$25	$40
- $5/MWh	-	$(20)	$(45)
Nuclear Capacity Factor			
+/- 1%	+/- $10	+/- $35	+/- $35

(1) Based on September 30, 2017, market conditions and hedged position; gas price sensitivities are based on an assumed gas-power relationship derived from an internal model that is updated periodically; power price sensitivities are derived by adjusting the power price assumption while keeping all other price inputs constant; due to correlation of the various assumptions, the hedged gross margin impact calculated by aggregating individual sensitivities may not be equal to the hedged gross margin impact calculated when correlations between the various assumptions are also considered; sensitivities based on commodity exposure which includes open generation and all committed transactions; excludes EDF's equity share of CENG Joint Venture

ExGen Hedged Gross Margin* Upside/Risk



(1) Represents an approximate range of expected gross margin, taking into account hedges in place, between the 5th and 95th percent confidence levels assuming all unhedged supply is sold into the spot market; approximate gross margin ranges are based upon an internal simulation model and are subject to change based upon market inputs, future transactions and potential modeling changes; these ranges of approximate gross margin in 2018 and 2019 do not represent earnings guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years; the price distributions that generate this range are calibrated to market quotes for power, fuel, load following products, and options as of September 30, 2017

(2) Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions

(3) Reflects ownership of FitzPatrick as of April 1, 2017, and TMI and Oyster Creek retirements in September 2019 and December 2019, respectively. EGTP removal impacts partial year 2017 and full year 2018 and 2019.

Illustrative Example of Modeling Exelon Generation 2018 Gross Margin*

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	← $3.9 billion →					
(B)	Capacity and ZEC	← $2.3 billion →					
(C)	Expected Generation (TWh)	95.8	60.5	19.5	15.5	8.0	
(D)	Hedge % (assuming mid-point of range)	75.5%	91.5%	78.5%	72.5%	87.5%	
(E=C*D)	Hedged Volume (TWh)	72.3	55.4	15.3	11.2	7.0	
(F)	Effective Realized Energy Price ($/MWh)	$29.50	$37.00	$3.50	$37.50	$2.50	
(G)	Reference Price ($/MWh)	$27.45	$30.77	$1.22	$27.29	$3.99	
(H=F-G)	Difference ($/MWh)	$2.05	$6.23	$2.28	$10.21	($1.49)	
(I=E*H)	Mark-to-Market value of hedges ($ million)(1)	$150	$345	$35	$115	($10)	
(J=A+B+I)	Hedged Gross Margin ($ million)	$6,850					
(K)	Power New Business / To Go ($ million)	$700					
(L)	Non-Power Margins Executed ($ million)	$200					
(M)	Non-Power New Business / To Go ($ million)	$300					
(N=J+K+L+M)	Total Gross Margin*	$8,050 million					

(1) Mark-to-market rounded to the nearest $5 million

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Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in $M)[1]	**2017**	**2018**	**2019**
Revenue Net of Purchased Power and Fuel Expense*[2,3]	**$8,575**	**$8,575**	**$8,025**
Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at merger date	$50	-	-
Other Revenues[4]	$(150)	$(200)	$(200)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses	$(475)	$(325)	$(325)
Total Gross Margin* (Non-GAAP)	**$8,000**	**$8,050**	**$7,500**

Key ExGen Modeling Inputs (in $M)[1,5]	**2017**
Other[6]	$175
Adjusted O&M*	$(4,850)
Taxes Other Than Income (TOTI)[7]	$(400)
Depreciation & Amortization[8]	$(1,075)
Interest Expense[9]	$(400)
Effective Tax Rate	**32.0%**

(1) All amounts rounded to the nearest $25M
(2) ExGen does not forecast the GAAP components of RNF separately, as to do so would be unduly burdensome. RNF also includes the RNF of our proportionate ownership share of CENG.
(3) Excludes the Mark-to-Market impact of economic hedging activities due to the volatility and unpredictability of the future changes to power prices
(4) Other Revenues reflects primarily revenues from Exelon Nuclear Partners, JExel Nuclear JV, variable interest entities, funds collected through revenues for decommissioning the former PECO nuclear plants through regulated rates, and gross receipts tax revenues
(5) ExGen amounts for O&M, TOTI, Depreciation & Amortization; excludes EDF's equity ownership share of the CENG Joint Venture
(6) Other reflects Other Revenues excluding gross receipts tax revenues, nuclear decommissioning trust fund earnings from unregulated sites, and the minority interest in ExGen Renewables JV and Bloom
(7) TOTI excludes gross receipts tax of $125M
(8) Excludes P&L neutral decommissioning depreciation
(9) Interest expense includes impact of reduced capitalized interest due to Texas CCGT plants in service as of May and June of 2017. Capitalized interest will be an additional ~$25M lower in 2018 as well due to this.

Exelon Utilities' Rate Case Filing Summaries

Exelon Utilities' Distribution Rate Case Schedule

	9/17	10/17	11/17	12/17	1/18	2/18	3/18
ACE Electric Distribution Rates - NJ	Settlement approved by NJBPU Sept 22						
Pepco Electric Distribution Rates - MD	Evidentiary Hearings Sept 5-15	Commission Order Received Oct 20					
ComEd Electric Distribution Formula Rate		Proposed Order Oct 19		Commission Order Expected Dec 9			
Delmarva – MD Electric Distribution Rates		Intervenor Direct Testimony Oct 16	Rebuttal Testimony Nov 16	Evidentiary Hearing Dec 11-20		Commission Order Expected Feb 14	
Delmarva – DE Electric Distribution Rates				Intervenor Direct Testimony Dec 6	Rebuttal Testimony Jan 12	Evidentiary Hearing Feb 20-22	
Delmarva – DE Gas Distribution Rates					Intervenor Direct Testimony Jan 16		Rebuttal Testimony Mar 5

Note: Based on current schedules of Illinois Commerce Commission, Maryland Public Service Commission, and Delaware Public Service Commission and are subject to change

Delmarva DE (Gas) Distribution Rate Case Filing

Docket No.	17-0978
Test Year	January 1, 2017 – December 31, 2017
Test Period	3 months actual and 9 months estimated
Requested Common Equity Ratio	50.52%
Requested Rate of Return	ROE: 10.10%; ROR: 6.98%
Proposed Rate Base (Adjusted)	$348M
Requested Revenue Requirement Increase	$12.9M(1)
Residential Total Bill % Increase	9.9%
Notes	• August 17, 2017, Delmarva DE filed application with Delaware Public Service Commission (DPSC) seeking increase in gas distribution base rates • Size of ask is driven by continued investments in gas distribution system to maintain and increase reliability and customer service • Forward looking reliability plant additions through August 2018 ($1.0M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request Procedural Schedule • Intervenor Direct Testimony Due: January 16, 2018 • Rebuttal Testimony Due: March 5, 2018 • Evidentiary Hearings: April 24-26, 2018 • Initial Briefs Due: May 14, 2018 • Reply Briefs Due: May 29, 2018 • Commission Order Expected: Q3 2018

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of $2.5 million on November 1, 2017, and will implement full allowable rates on March 17, 2018, subject to refund

Delmarva DE (Electric) Distribution Rate Case Filing

Docket No.	17-0977
Test Year	January 1, 2017– December 31, 2017
Test Period	3 months actual and 9 months estimated
Requested Common Equity Ratio	50.52%
Requested Rate of Return	ROE: 10.10%; ROR: 6.98%
Proposed Rate Base (Adjusted)	$805M
Requested Revenue Requirement Increase	$31.2M(1)
Residential Total Bill % Increase	4.6%
Notes	• August 17, 2017, Delmarva DE filed application with DPSC seeking increase in electric distribution base rates • Size of ask is driven by continued investments in electric distribution system to maintain and increase reliability and customer service • Forward looking reliability plant additions through August 2018 ($3.1M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request • Potential delay due to Staff and Division of the Public Advocate (DPA) joint motion to dismiss the application, which states that the increase of the requested increase to $31.2 million required additional time to review Procedural Schedule: • Intervenor Direct Testimony Due: December 6, 2017 • Rebuttal Testimony Due: January 12, 2018 • Evidentiary Hearings: February 20-22, 2018 • Initial Briefs Due: March 16, 2018 • Reply Briefs Due: March 30, 2018 • Commission Order Expected: Q3 2018

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of $2.5 million on October 16, 2017, and will implement full allowable rates on March 17, 2018, subject to refund

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Delmarva MD (Electric) Distribution Rate Case Filing

Formal Case No.	9455
Test Year	October 1, 2016 – September 30, 2017
Test Period	7 months actual and 5 months estimated
Requested Common Equity Ratio	50.68%
Requested Rate of Return	ROE: 10.10%; ROR: 7.05%
Proposed Rate Base (Adjusted) (Updated on Sept. 28, 2017)	$775M
Requested Revenue Requirement Increase (Updated on Sept. 28, 2017)	$21.6M(1)
Residential Total Bill % Increase	1.8%
Notes	• July 14, 2017, Delmarva MD filed application with Maryland Public Service Commission (MDPSC) seeking increase in electric distribution base rates • Forward looking reliability and other plant additions through April 2018 ($3.1M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request Intervenor Positions: • Office of People's Council (OPC) revenue increase of $5.0M or $7.2M based on 8.65% or 9.0% ROE, respectively • Staff revenue increase of $11.1M based on 9.30% ROE Procedural Schedule: • Intervenor Direct Testimony Due: October 16, 2017 • Rebuttal Testimony Due: November 16, 2017 • Evidentiary Hearings: December 11 – 20, 2017 • Briefs due: January 9, 2018 • Commission Order Expected: February 14, 2018

(1) Amount represents adjusted requested revenue requirement filed on September 28, 2017

Exelon.

ComEd April 2017 Distribution Formula Rate

The 2017 distribution formula rate filing established the net revenue requirement used to set the rates that will take effect in January 2018 after the Illinois Commerce Commission's (ICC's) review. There are two components to the annual distribution formula rate filing:

- Filing Year: Based on 2016 costs and 2017 projected plant additions
- Annual Reconciliation: For 2016, this amount reconciles the revenue requirement reflected in rates in effect during 2016 to the actual costs for that year. The annual reconciliation impacts cash flow in 2018 but the earnings impact has been recorded in 2016 as a regulatory asset.

Docket #	17-0196
Filing Year	**2016 Calendar Year Actual Costs and 2017 Projected Net Plant Additions** are used to set the rates for calendar year 2018. Rates currently in effect (docket 16-0259) for calendar year 2017 were based on 2015 actual costs and 2016 projected net plant additions.
Reconciliation Year	**Reconciles Revenue Requirement reflected in rates during 2016 to 2016 Actual Costs Incurred.** Revenue requirement for 2016 is based on docket 15-0287 (2014 actual costs and 2015 projected net plant additions) approved in December 2015.
Common Equity Ratio	**~46%** for both the filing and reconciliation year
ROE	**8.40%** for the filing year (2016 30-yr Treasury Yield of 2.60% + 580 basis point risk premium) and **8.34%** for the reconciliation year (2016 30-yr Treasury Yield of 2.60% + 580 basis point risk premium – 6 basis points performance metrics penalty). For 2017 and 2018, the actual allowed ROE reflected in net income will ultimately be based on the average of the 30-year Treasury Yield during the respective years plus 580 basis point spread, absent any metric penalties
Requested Rate of Return	**~6.5%** for both the filing and reconciliation years
Rate Base(1)	**$9,662 million–** Filing year (represents projected year-end rate base using 2016 actual plus 2017 projected capital additions). 2017 and 2018 earnings will reflect 2017 and 2018 year-end rate base respectively. $8,807 million - Reconciliation year (represents year-end rate base for 2016)
Revenue Requirement Increase(1)	**$95.6M increase** ($17.5M increase due to the 2016 reconciliation and collar adjustment in addition to a $78.1M increase related to the filing year). The 2016 reconciliation impact on net income was recorded in 2016 as a regulatory asset.
Timeline	• 04/13/17 Filing Date • 240 Day Proceeding • ICC Order expected to be issued by December 9, 2017

Given the retroactive ratemaking provision in the Energy Infrastructure Modernization Act (EIMA) legislation, ComEd net income during the year will be based on actual costs with a regulatory asset/liability recorded to reflect any under/over recovery reflected in rates. Revenue Requirement in rate filings impacts cash flow.

(1) Amount represents ComEd's position filed in Rebuttal testimony on July 21, 2017

Pepco MD Distribution Rate Case Final Order

Formal Case No.	9443	Per Commission Order
Test Year	May 1, 2016 – April 30, 2017	
Test Period	8 months actual and 4 months estimated (Updated on August 24, 2017)	
Requested Common Equity Ratio	50.15%	50.15%
Requested Rate of Return	ROE: 10.10%; ROR: 7.74%	ROE: 9.50%; ROR: 7.43%
Proposed Rate Base (Adjusted)	$1.7B	$1.6B
Requested Revenue Requirement Increase	$67.0M	$32.4M
Residential Total Bill % Increase	5.6%	2.99%
Notes	• March 24, 2017, Pepco MD filed application with MDPSC seeking increase in electric distribution base rates • Normalization of tax benefits on pre-1981 removal costs • 8 month forward looking reliability and other plant additions from May 2017 through December 2017 ($13.3M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request Intervenor Positions: • Office of People's Council (OPC) revenue increase of $9.95M or $13.44M based on 8.75% or 9.0% ROE, respectively • Apartment and Office Building Association (AOBA) revenue increase of $24.76M based on 9.10% ROE • Commission Technical Staff (Staff) revenue increase of $25.76M based on 9.39% ROE • Commission Order Expected: October 20, 2017	• Order received on October 20th • Two months of post-test period reliability capital placed in service through June 2017 approved • Remaining deferred balance of storm costs for Sandy and Derecho to be amortized over 12 months • Expansion of test year to a minimum of 6 months of forecasted data was denied • Pepco's proposal to normalize tax benefits for pre-1981 removal costs to be addressed in the next base rate case • Approximately $400K of AIP expense was excluded from recovery as a result of the Company not achieving its 2016 SAIFI merger target

Atlantic City Electric NJ Rate Case Final Order

BPU Docket No.	ER17030308	Per Settlement
Test Year	August 1, 2016 – July 31, 2017 (Updated on July 14, 2017)	
Test Period	5 months actual and 7 months forecasted	
Stipulated Common Equity Ratio	Requested 50.14%	50.47%
Stipulated Rate of Return	ROE: 10.10%; ROR: 7.83%	ROE: 9.60% ROR: 7.60%
Stipulated Rate Base (Adjusted)	$1.4B	$1.3B
Stipulated Revenue Requirement Increase	$72.6M	$43.0M
Stipulated Residential Total Bill % Increase	6.57%	4.03%
Notes	• March 30, 2017, Atlantic City Electric filed application with New Jersey Board of Public Utilities (NJBPU) seeking increase in electric distribution base rates • Recovery of investment in infrastructure to maintain and harden electric distribution system • Ratemaking adjustments to address declining sales • Proposal of a Non-Incremental System Renewal Recovery Charge for recovery of non-incremental reliability spend over four years (2018-2021) of $376M	• Settlement Approved by NJBPU: September 22, 2017 • Rate Effective Date: October 1, 2017 • Approval for regulatory asset treatment of costs to achieve • Company agreed to withdraw its request to implement a System Renewal Recovery Charge • Company agreed to prepare proposal for phasing out accelerated reliability spending in Reliability Improvement Plan

Pepco DC Distribution Rate Case Final Order

Formal Case No.	1139	**Per Commission Order**
Test Year	April 1, 2015 – March 31, 2016	
Test Period	12 months actual	
Requested Common Equity Ratio	49.14%	49.14%
Requested Rate of Return	ROE: 10.60%; ROR: 8.00%	ROE: 9.50%; ROR: 7.46%
Proposed Rate Base (Adjusted)	$1.7B	$1.6B
Requested Revenue Requirement Increase	$77.5M(1)	$36.9M
Residential Total Bill % Increase	4.62%	2.52%

Notes	• June 30, 2016, Pepco filed application with District of Columbia Public Service Commission (DCPSC) seeking increase in electric distribution base rates
	Intervenor Positions:
	• Office of People's Council (OPC) revenue increase of $25.8M based on 8.60% ROE
	• Apartment and Office Building Association (AOBA) revenue increase of $62.2M based on 9.25% ROE
	• Healthcare Council of the National Capital Area (HCNCA) revenue increase of $16.8M based on 8.75% ROE
	• District of Columbia Water and Sewer Authority (DC Water) revenue increase of $52.7M based on 9.10% ROE
		• July 25, 2017, DCPSC issued Final Order
		• Bill Stabilization Adjustment (BSA) remains unchanged
		• Approval to establish regulatory asset for costs to achieve (CTA)
		• Customer Base Rate Credit (CBRC) will offset monthly bill increases
		    • $15M allocated to residential customers
		    • $2.3M designated to certain small commercial customers
		    • $6-7M reserved for disabled and senior citizens on fixed incomes in future rate cases
		• Recovery of $27.4M of AMI, direct load control and dynamic pricing regulatory assets to be amortized over 5 years

(1) Revenue requirement includes changes in amortization expense, which has no impact on pre-tax earnings

Appendix

Reconciliation of Non-GAAP Measures

Q3 2016 QTD GAAP EPS Reconciliation

Three Months Ended September 30, 2016	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2016 GAAP Earnings (Loss) Per Share	**$0.25**	**$0.04**	**$0.13**	**$0.06**	**$0.18**	**($0.13)**	**$0.53**
Mark-to-market impact of economic hedging activities	(0.06)	-	-	-	-	-	(0.06)
Unrealized gains related to NDT fund investments	(0.07)	-	-	-	-	-	(0.07)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	0.01	-	-	-	-	-	0.01
Merger commitments	-	-	-	-	(0.04)	0.05	0.01
Long-Lived asset impairments	0.01	-	-	-	-	-	0.01
Plant retirements and divestitures	0.22	-	-	-	-	-	0.22
Cost management program	0.01	-	-	-	-	-	0.01
Like-kind exchange tax position	-	0.16	-	-	-	0.05	0.21
CENG noncontrolling interest	0.03	-	-	-	-	-	0.03
2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.41**	**$0.20**	**$0.13**	**$0.06**	**$0.14**	**$(0.03)**	**$0.91**

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

Q3 2017 QTD GAAP EPS Reconciliation

Three Months Ended September 30, 2017	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2017 GAAP (Loss) Earnings Per Share	**$0.32**	**$0.20**	**$0.12**	**$0.06**	**$0.16**	**($0.00)**	**$0.85**
Mark-to-market impact of economic hedging activities	(0.05)	-	-	-	-	-	(0.05)
Unrealized gains related to NDT fund investments	(0.07)	-	-	-	-	-	(0.07)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	0.01	-	-	-	(0.01)	-	-
Long-lived asset impairments	0.03	-	-	-	-	-	0.03
Plant retirements and divestitures	0.08	-	-	-	-	-	0.08
Cost management program	0.01	-	-	-	-	-	0.01
Reassessment of state deferred income taxes	0.02	-	-	-	-	(0.04)	(0.02)
Bargain purchase gain	(0.01)	-	-	-	-	-	(0.01)
CENG noncontrolling interest	0.02	-	-	-	-	-	0.02
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.36**	**$0.19**	**$0.12**	**$0.07**	**$0.15**	**($0.04)**	**$0.85**

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

Q3 2016 YTD GAAP EPS Reconciliation

Nine Months Ended September 30, 2016	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2016 GAAP Earnings (Loss) Per Share	**$0.58**	**$0.32**	**$0.37**	**$0.20**	**($0.10)**	**$(0.37)**	**$1.00**
Mark-to-market impact of economic hedging activities	0.07	-	-	-	-	-	0.07
Unrealized gains related to NDT fund investments	(0.13)	-	-	-	-	-	(0.13)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	0.02	-	-	-	0.04	0.04	0.10
Merger commitments	-	-	-	-	0.26	0.17	0.43
Long-lived asset impairments	0.11	-	-	-	-	-	0.11
Plant retirements and divestitures	0.37	-	-	-	-	-	0.37
Reassessment of state deferred income taxes	0.01	-	-	-	-	(0.01)	-
Cost management program	0.02	-	-	-	-	-	0.03
Like-kind exchange tax position	-	0.16	-	-	-	0.05	0.21
CENG noncontrolling interest	0.04	-	-	-	-	-	0.04
2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$1.10**	**$0.48**	**$0.37**	**$0.20**	**$0.20**	**$(0.11)**	**$2.24**

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

Exelon.

Q3 2017 YTD GAAP EPS Reconciliation

Nine Months Ended September 30, 2017	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2017 GAAP Earnings (Loss) Per Share	**$0.51**	**$0.47**	**$0.35**	**$0.24**	**$0.38**	**$0.06**	**$2.01**
Mark-to-market impact of economic hedging activities	0.10	-	-	-	-	-	0.10
Unrealized gains related to NDT fund investments	(0.22)	-	-	-	-	-	(0.22)
Amortization of commodity contract intangibles	0.03	-	-	-	-	-	0.03
Merger and integration costs	0.05	-	-	-	(0.01)	-	0.04
Merger commitments	(0.02)	-	-	-	(0.06)	(0.06)	(0.15)
Long-lived asset impairments	0.31	-	-	-	-	-	0.31
Plant retirements and divestitures	0.15	-	-	-	-	-	0.15
Reassessment of state deferred income taxes	0.02	-	-	-	-	(0.06)	(0.04)
Cost management program	0.02	-	-	-	-	-	0.03
Like-kind exchange tax position	-	0.02	-	-	-	(0.05)	(0.03)
Asset retirement obligation	-	-	-	-	-	-	-
Tax settlements	(0.01)	-	-	-	-	-	(0.01)
Bargain purchase gain	(0.25)	-	-	-	-	-	(0.25)
CENG noncontrolling interest	0.08	-	-	-	-	-	0.08
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.76**	**$0.50**	**$0.35**	**$0.25**	**$0.31**	**($0.12)**	**$2.05**

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

Exelon.

GAAP to Operating Adjustments

- **Exelon's 2017 adjusted (non-GAAP) operating earnings excludes the earnings effects of the following:**
  - Mark-to-market adjustments from economic hedging activities
  - Unrealized gains from NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements
  - Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at the ConEdison Solutions and FitzPatrick acquisition dates
  - Certain merger and integration costs associated with the PHI and FitzPatrick acquisitions
  - Adjustments to reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions
  - Impairments as a result of the ExGen Texas Power, LLC assets held for sale
  - Plant retirements and divestitures at Generation
  - Non-cash impact of the remeasurement of state deferred income taxes, related to changes in statutory tax rates and changes in forecasted apportionment
  - Costs incurred related to a cost management program
  - Certain adjustments related to Exelon's like-kind exchange tax position
  - Non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units
  - Benefits related to the favorable settlement of certain income tax positions related to PHI's unregulated business interests
  - The excess of the fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition
  - Generation's noncontrolling interest, primarily related to CENG exclusion items

GAAP to Non-GAAP Reconciliations

YE 2017 Exelon FFO Calculation ($M)[1,2,10,11]	
GAAP Operating Income	$3,500
Depreciation & Amortization	$3,350
EBITDA	$6,850
+/- Non-operating activities and nonrecurring items[3]	$450
- Interest Expense	($1,450)
+ Current Income Tax (Expense)/Benefit	$325
+ Nuclear Fuel Amortization	$1,075
+/- Other S&P Adjustments[4]	$350
= FFO (a)	**$7,600**

YE 2017 Exelon Adjusted Debt Calculation ($M)[1,2,10]	
Long-Term Debt (including current maturities)	$32,050
Short-Term Debt	$1,125
+ PPA Imputed Debt[5]	$350
+ Operating Lease Imputed Debt[6]	$875
+ Pension/OPEB Imputed Debt[7]	$4,100
- Off-Credit Treatment of Debt[8]	($1,725)
- Surplus Cash Adjustment[9]	($600)
+/- Other S&P Adjustments[4]	($650)
= Adjusted Debt (b)	**$35,525**

YE 2017 Exelon FFO/Debt[1,2]		
FFO (a) / Adjusted Debt (b)	=	21%

(1) All amounts rounded to the nearest $25M
(2) Calculated using S&P Methodology. Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment.
(3) Reflects impact of operating adjustments on GAAP EBITDA
(4) Includes other adjustments as prescribed by S&P
(5) Reflects present value of net capacity purchases
(6) Reflects present value of minimum future operating lease payments
(7) Reflects after-tax unfunded pension/OPEB
(8) Includes non-recourse project debt
(9) Applies 75% of excess cash against balance of LTD
(10) Reflects removal of EGTP
(11) Reflects delay in Illinois ZEC revenue recognition from 2017 to 2018

GAAP to Non-GAAP Reconciliations

YE 2017 ExGen Net Debt Calculation ($M)[1,3]	
Long-Term Debt (including current maturities)	$8,775
Short-Term Debt	$350
- Surplus Cash Adjustment	($300)
= Net Debt (a)	**$8,825**

YE 2017 ExGen Net Debt Calculation ($M)[1,3]	
Long-Term Debt (including current maturities)	$8,775
Short-Term Debt	$350
- Surplus Cash Adjustment	($300)
- Nonrecourse Debt	($1,925)
= Net Debt (a)	**$6,900**

YE 2017 ExGen Operating EBITDA Calculation ($M)[1,3,4]	
GAAP Operating Income	$775
Depreciation & Amortization	$1,375
EBITDA	$2,150
+/- Non-operating activities and nonrecurring items[2]	$725
= Operating EBITDA (b)	**$2,875**

YE 2017 ExGen Operating EBITDA Calculation ($M)[1,3,4]	
GAAP Operating Income	$775
Depreciation & Amortization	$1,375
EBITDA	$2,150
+/- Non-operating activities and nonrecurring items[2]	$725
- EBITDA from projects financed by nonrecourse debt	($250)
= Operating EBITDA (b)	**$2,625**

YE 2017 Book Debt / EBITDA

$$\frac{\text{Net Debt (a)}}{\text{Operating EBITDA (b)}} = 3.1x$$

YE 2017 Recourse Debt / EBITDA

$$\frac{\text{Net Debt (a)}}{\text{Operating EBITDA (b)}} = 2.6x$$

(1) All amounts rounded to the nearest $25M
(2) Reflects impact operating adjustments on GAAP EBITDA
(3) Reflects removal of EGTP
(4) Reflects delay in Illinois ZEC revenue recognition from 2017 to 2018

GAAP to Non-GAAP Reconciliations

Q3 2017 Operating ROE Reconciliation ($M)[1]	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP)[1]	$85	$114	$210	$1,281	$1,690
Operating Exclusions	($23)	($12)	($25)	$34	($25)
Adjusted Operating Earnings[1]	$63	$103	$185	$1,315	$1,665
Average Equity	$1,061	$1,323	$2,419	$12,750	$17,554
Operating ROE (Adjusted Operating Earnings/Average Equity)	**5.9%**	**7.8%**	**7.7%**	**10.3%**	**9.5%**

Q2 2017 Operating ROE Reconciliation ($M)[1]	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP)[1]	$91	$127	$203	$1,132	$1,548
Operating Exclusions	($25)	($32)	($29)	$186	$105
Adjusted Operating Earnings[1]	$66	$95	$174	$1,318	$1,653
Average Equity	$1,039	$1,300	$2,390	$12,308	$17,038
Operating ROE (Adjusted Operating Earnings/Average Equity)	**6.4%**	**7.3%**	**7.3%**	**10.7%**	**9.7%**

(1) ACE, Delmarva, and Pepco represents full year of earnings

Exelon.

GAAP to Non-GAAP Reconciliations

2017 Adjusted Cash from Ops Calculation ($M)(1)	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
Net cash flows provided by operating activities (GAAP)	$1,375	$750	$775	$1,175	$3,400	($250)	$7,225
Other cash from investing activities	-	-	-	-	($275)	-	($275)
Intercompany receivable adjustment	($350)	-	-	-	-	$350	-
Counterparty collateral activity	-	-	-	-	$200	-	$200
Adjusted Cash Flow from Operations	**$1,025**	**$750**	**$775**	**$1,175**	**$3,350**	**$75**	**$7,150**

2017 Cash From Financing Calculation ($M)(1)	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	$825	$175	$150	$125	($300)	$400	$1,375
Dividends paid on common stock	$425	$300	$200	$325	$650	($675)	$1,225
Intercompany receivable adjustment	$350	-	-	-	-	($350)	-
Financing Cash Flow	**$1,600**	**$475**	**$350**	**$450**	**$350**	**($625)**	**$2,625**

Exelon Total Cash Flow Reconciliation(1)	2017
GAAP Beginning Cash Balance	**$650**
Adjustment for Cash Collateral Posted	$400
Adjusted Beginning Cash Balance(3)	$1,050
Net Change in Cash (GAAP)(2)	$400
Adjusted Ending Cash Balance(3)	$1,450
Adjustment for Cash Collateral Posted	($625)
GAAP Ending Cash Balance	**$825**

(1) All amounts rounded to the nearest $25M. Items may not sum due to rounding.
(2) Represents the GAAP measure of net change in cash, which is the sum of cash flow from operations, cash from investing activities, and cash from financing activities. Figures reflect cash capital expenditures and CENG fleet at 100%.
(3) Adjusted Beginning and Ending cash balances reflect GAAP Beginning and End Cash Balances excluding counterparty collateral activity

GAAP to Non-GAAP Reconciliations

ExGen Adjusted O&M Reconciliation ($M)[1]	2017	2018	2019	2020
GAAP O&M	**$6,325**	**$5,300**	**$5,150**	**$5,025**
Decommissioning[2]	25	50	50	50
TMI Retirement	(75)	-	-	-
EGTP Impairment	(450)	-	-	-
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses[3]	(425)	(325)	(325)	(325)
O&M for managed plants that are partially owned	(425)	(425)	(400)	(425)
Other	(125)	(25)	(25)	(25)
Adjusted O&M (Non-GAAP)	**$4,850**	**$4,600**	**$4,450**	**$4,300**

2017-2020 ExGen Free Cash Flow Calculation ($M)[1]	
Cash from Operations (GAAP)	$15,150
Other Cash from Investing and Activities	($650)
Baseline Capital Expenditures[4]	($4,025)
Nuclear Fuel Capital Expenditures	($3,625)
Free Cash Flow before Growth CapEx and Dividend	**$6,825**

(1) All amounts rounded to the nearest $25M. Items may not sum due to rounding.
(2) Reflects earnings neutral O&M
(3) Reflects the direct cost of sales of certain businesses, which are included in Total Gross Margin*
(4) Baseline capital expenditures refer to maintenance and required capital expenditures necessary for day-to-day plant operations and includes merger commitments