

# Earnings Conference Call 4<sup>th</sup> Quarter 2016

February 8, 2017



## Cautionary Statements Regarding Forward-Looking Information

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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 (PHI), 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 2015 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 23; (2) PHI's 2015 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 16; (3) Exelon's Third Quarter 2016 Quarterly Report on Form 10-Q 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 (4) 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 presentation. 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

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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 (non-GAAP) operating earnings, adjusted (non-GAAP) operating and maintenance expense, total gross margin, and adjusted cash flow from operations (non-GAAP) or free cash flow. Adjusted (non-GAAP) 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 costs, certain costs incurred associated with the PHI acquisition, merger commitments related to the settlement of the PHI acquisition, the impairment of certain long-lived assets, plant retirements and divestitures, costs related to the cost management program, the non-controlling interest in CENG, and other items as set forth in the reconciliation in the Appendix. Adjusted (non-GAAP) operating and maintenance expense excludes regulatory operating and maintenance costs for the utility businesses and direct cost of sales for certain Constellation businesses, decommissioning costs that do not affect profit and loss, the impact from operating and maintenance expense related to variable interest entities at Generation, and other items as set forth in the reconciliation in the Appendix. Total gross margin (non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, the operating services agreement with Fort Calhoun, variable interest entities and net of direct cost of sales for certain Constellation businesses. Adjusted cash flow from operations (non-GAAP) or free cash flow 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. Due to the forward-looking nature of any forecasted non-GAAP measures, information to reconcile the forecast adjusted (non-GAAP) measures to the most directly comparable GAAP measure is not currently available, as management is unable to project all of these items for future periods.

## Non-GAAP Financial Measures Continued

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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 measure 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. Reconciliations of these non-GAAP measures to the most comparable GAAP measures are provided in the footnotes, appendices and attachments to this presentation.

## 2016 Milestone Accomplishments

Financial	Growth	Regulatory & Policy	Employees & Community
<ul style="list-style-type: none"> <li>Delivered FY 2016 GAAP earnings of \$1.22 and adjusted operating earnings of \$2.68 per share, within our guidance range<sup>(1)</sup></li> <li>Implemented 2.5% annual dividend growth strategy through 2018</li> <li>Named as the only Utility on the Fortune 100 list</li> <li>Exelon's diverse supplier spend reached \$1.9B in 2016, up 202% since 2011</li> </ul>	<ul style="list-style-type: none"> <li>Completed the acquisition of PHI, adding \$8.3B of rate base</li> <li>Invested \$5.2B of capital to improve reliability at our regulated Utilities excluding the merger</li> <li>Completed acquisition of ConEd Solutions</li> <li>Pending acquisition of the FitzPatrick nuclear power station</li> </ul>	<ul style="list-style-type: none"> <li>IL and NY ZEC Programs will preserve five nuclear plants at risk of closure</li> <li>IL Legislation provides ComEd a fair return on energy efficiency investments that benefit our customers and also extends EIMA formula rate to 2022</li> <li>Completed distribution rate cases providing \$317M in revenue increases with another \$80M for FERC transmission</li> </ul>	<ul style="list-style-type: none"> <li>Commitment to our workforce through best in industry parental leave program and first utility to sign the Equal Pay pledge</li> <li>Exelon employees donated 171,341 hours to volunteer initiatives and Exelon donated \$46M to our local communities</li> </ul>

(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

# Best in Class Utility Operations

## Exelon Utilities Operational Metrics

Operations	Metric	2016			
		BGE	PECO	ComEd	PHI
Electric Operations	OSHA Recordable Rate	Green	Green	Green	Yellow
	2.5 Beta SAIFI (Outage Frequency)	Yellow	Green	Green	Orange
	2.5 Beta CAIDI (Outage Duration)	Green	Green	Green	Yellow
Customer Operations	Customer Satisfaction	Green	Green	Green	N/A
	Service Level % of Calls Answered in <30 sec	Green	Green	Green	Green
	Abandon Rate	Green	Green	Green	Green
Gas Operations	Percent of Calls Responded to in <1 Hour	Green	Green	No Gas Operations	Green

## Comments

- Operationally, the utilities ended the year with strong results across key metrics.
  - BGE, ComEd, and PECO achieved 1<sup>st</sup> decile performance in Customer Satisfaction Index (CSI) that was the best ever performance for each utility
  - PECO achieved 1<sup>st</sup> decile performance in OSHA Recordable Rate
  - ComEd and PECO achieved 1<sup>st</sup> decile performance for outage frequency. ComEd's results were best on record and best in class.
  - PHI outage frequency performance was best ever on record

Exelon Utilities has identified and transferred best practices at each of its utilities to improve operating performance in areas such as:

- System Performance
- Emergency Preparedness
- Corrective and Preventive Maintenance
- Customer Care

Q1	Q2
Q3	Q4



## Best in Class at ExGen and Constellation

### Exelon Generation Operational Metrics

- Continued best in class performance across our Nuclear fleet:
  - Capacity Factor of 94.6% is the highest ever for Exelon
  - Most power ever generated at 153M MWh<sup>(1)</sup>
  - All-time shortest refueling outage duration average of 22 days
- Strong performance across our Fossil and Renewable fleet:
  - Renewables energy capture: 95.6%
  - Power dispatch match: 97.2%

### Constellation Metrics

**77%** retail power customer renewal rate

**28%** power new customer win rate

**91%** natural gas customer retention rate

**25** month average power contract term

Average customer duration of more than **5** years

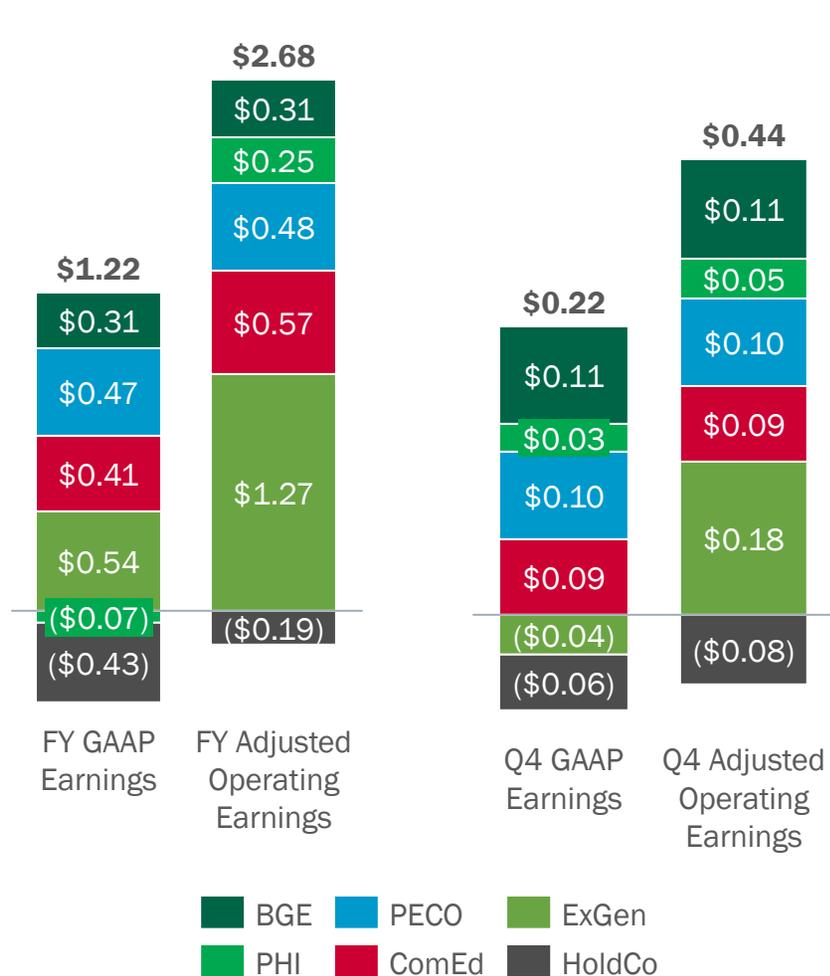
Stable Retail Margins

**Closed on ConEdison Solutions transaction, adding more than 560,000 customers**

(1) Reflects generation output at ownership

# Strong 2016 Financial Results

## 2016 EPS Results<sup>(1,2)</sup>



- Adjusted (non-GAAP) operating earnings full year drivers versus guidance:

### Utilities

↑ Weather

↑ Lower O&M

### Exelon Generation

↑ Lower cost to serve

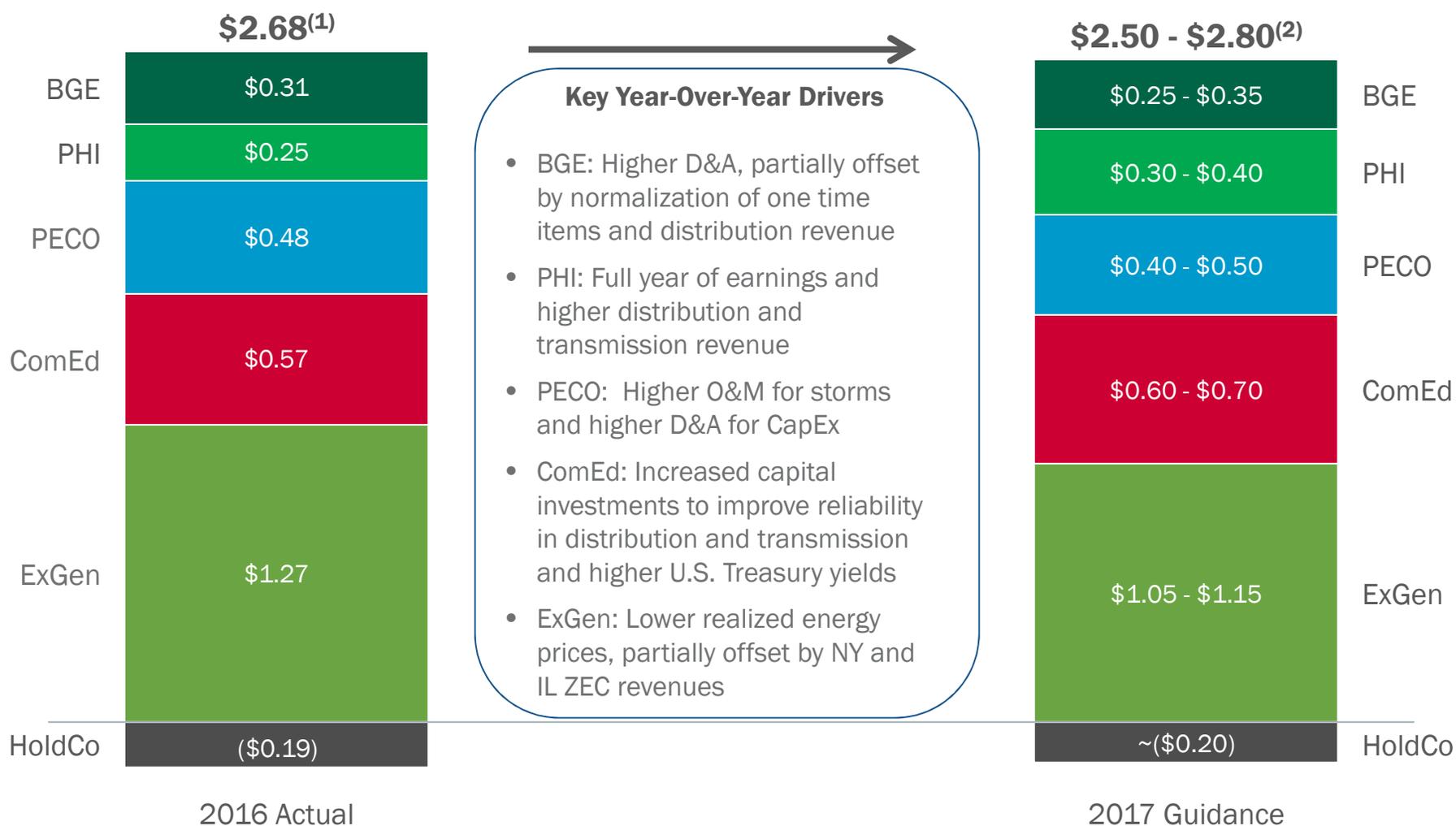
↑ Nuclear Generation Output

(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

(2) Amounts may not add due to rounding



# 2017 Adjusted Operating Earnings Guidance

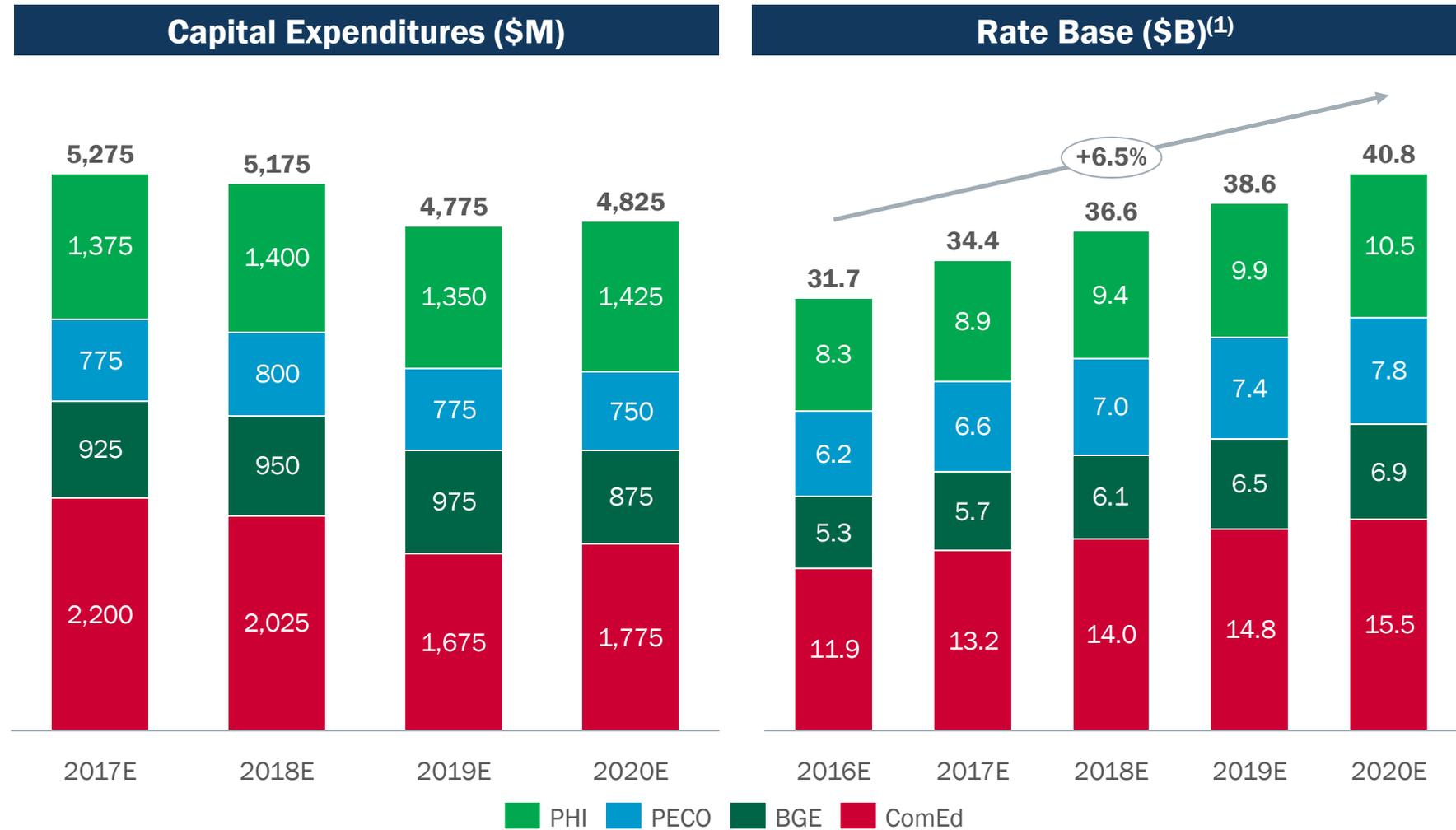


**Expect Q1 2017 Adjusted Operating Earnings of \$0.55 - \$0.65 per share**

(1) 2016 results based on 2016 average outstanding shares of 927M. Refer to Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS.  
 (2) 2017 earnings guidance based on expected average outstanding shares of 949M. Earnings guidance for OpCos may not add up to consolidated EPS guidance. Refer to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS guidance to GAAP EPS.



# Our Capital Plan Drives Stable Earnings Growth



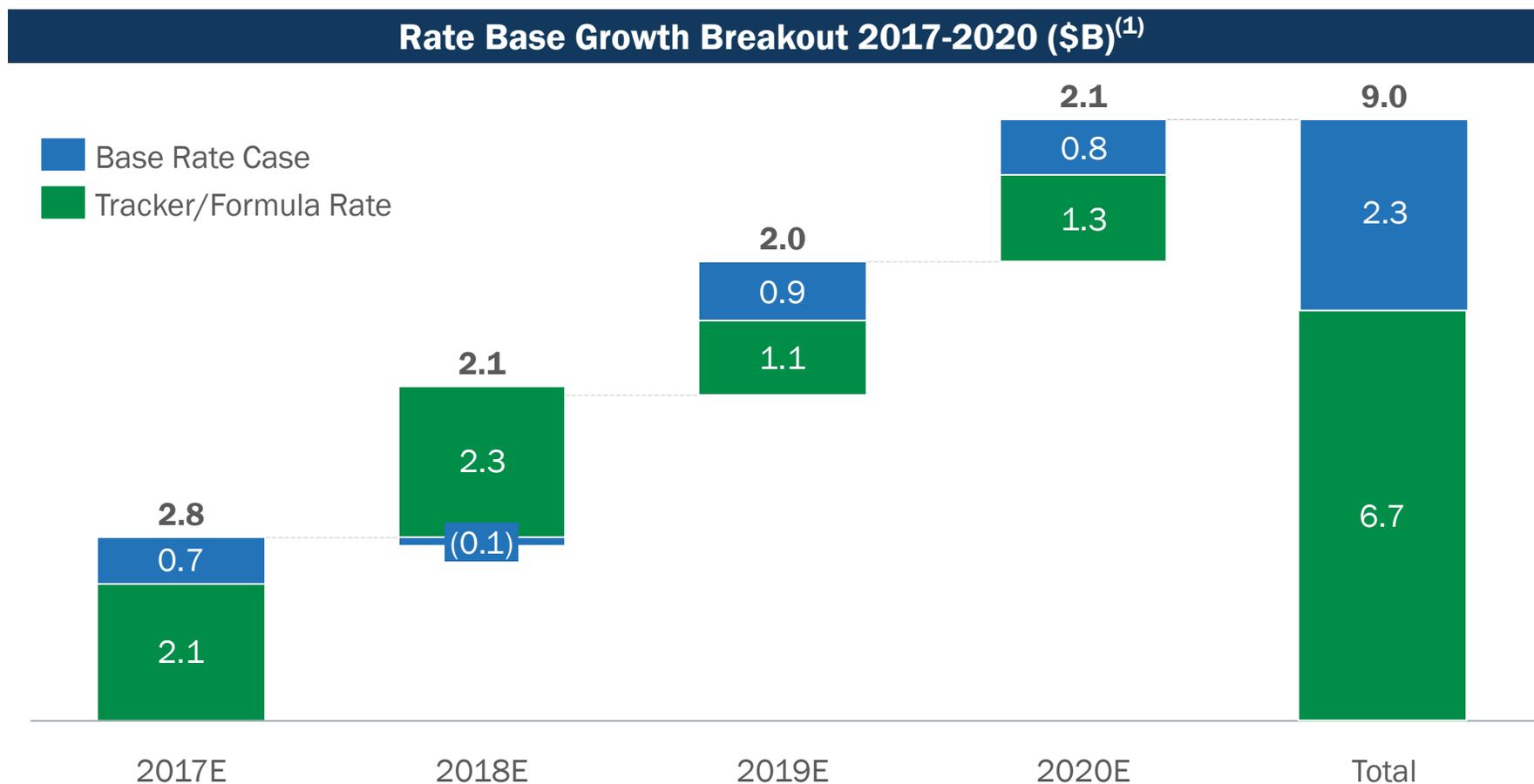
**Over \$20B of capital is being invested at utilities from 2017-2020 to improve reliability**

Note: CapEx numbers are rounded to nearest \$25M and numbers may not add due to rounding

(1) Rate base reflects year-end estimates



# Formulaic Mechanisms Cover Bulk of Rate Base Growth



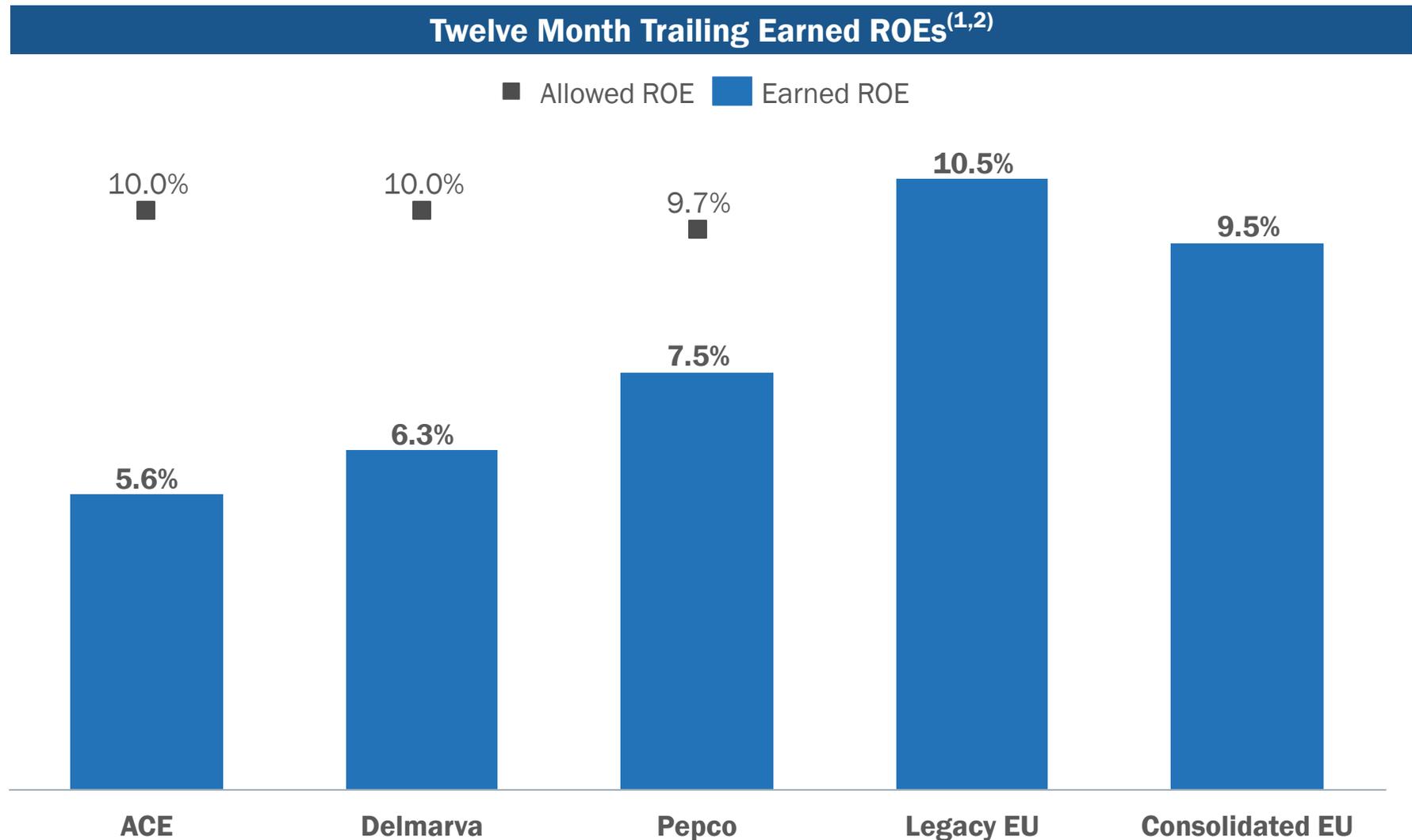
**Of the approximately \$9.0 billion of rate base growth Exelon Utilities forecasts over the next 4 years, ~75% will be recovered through existing formula and tracker mechanisms**

Note: Numbers may not add due to rounding

(1) Assumes PECO transmission formula rate beginning in 2018; base rate base decrease due to reclassification of transmission rate base growth at PECO



# Weighted Average Allowed vs Earned ROE Comparison



(1) Operating ROE is calculated using operating net income divided by simple average equity for the period 12/31/15 – 12/31/16. The operating net income is reflective of all lines of business (Electric Distribution, Gas Distribution, Transmission).

(2) For a reconciliation of operating ROE, which is a non-GAAP measure derived from adjusted operating earnings, please refer to slide 78 in the Appendix

## Exelon Utilities Distribution Rate Case Summary

BGE Final Order		Delmarva MD Filing	
Authorized Revenue Requirement Increase <sup>(1,3)</sup>	\$92M	Requested Revenue Requirement Increase <sup>(1)</sup>	\$57M
Authorized ROE	9.75% (9.65% Gas)	Requested ROE	10.60%
Common Equity Ratio	51.90%	Requested Common Equity Ratio	49.10%
Order Received <sup>(3)</sup>	6/3/16	Order Expected	2/17/17
ACE Electric Final Order		Pepco DC Filing	
Authorized Revenue Requirement Increase <sup>(1)</sup>	\$45M	Requested Revenue Requirement Increase <sup>(1)</sup>	\$76.8M
Authorized ROE	9.75%	Requested ROE	10.60%
Common Equity Ratio	49.48%	Requested Common Equity Ratio	49.14%
Commission Approved Settlement	8/24/16	Order Expected	7/25/17
Pepco MD Final Order		Delmarva DE Electric Filing	
Requested Revenue Requirement Increase <sup>(1)</sup>	\$52.5M	Requested Revenue Requirement Increase <sup>(1)</sup>	\$60.2M
Requested ROE	9.55%	Requested ROE	10.60%
Requested Common Equity Ratio	49.55%	Requested Common Equity Ratio	49.44%
Order Received	11/15/16	Order Expected	Q3 2017
ComEd Final Order		Delmarva DE Gas Filing	
Requested Revenue Requirement Increase <sup>(2)</sup>	\$127M	Requested Revenue Requirement Increase <sup>(1)</sup>	\$21.5M
Authorized ROE	8.64%	Requested ROE	10.60%
Common Equity Ratio	46%	Requested Common Equity Ratio	49.44%
Order Received	12/6/16	Order Expected	Q3 2017
Cumulative Final Orders			
Authorized Revenue Requirement Increase <sup>(1)</sup>		\$317M	

(1) Revenue requirement includes changes in depreciation and amortization expense where applicable, which have no impact on pre-tax earnings

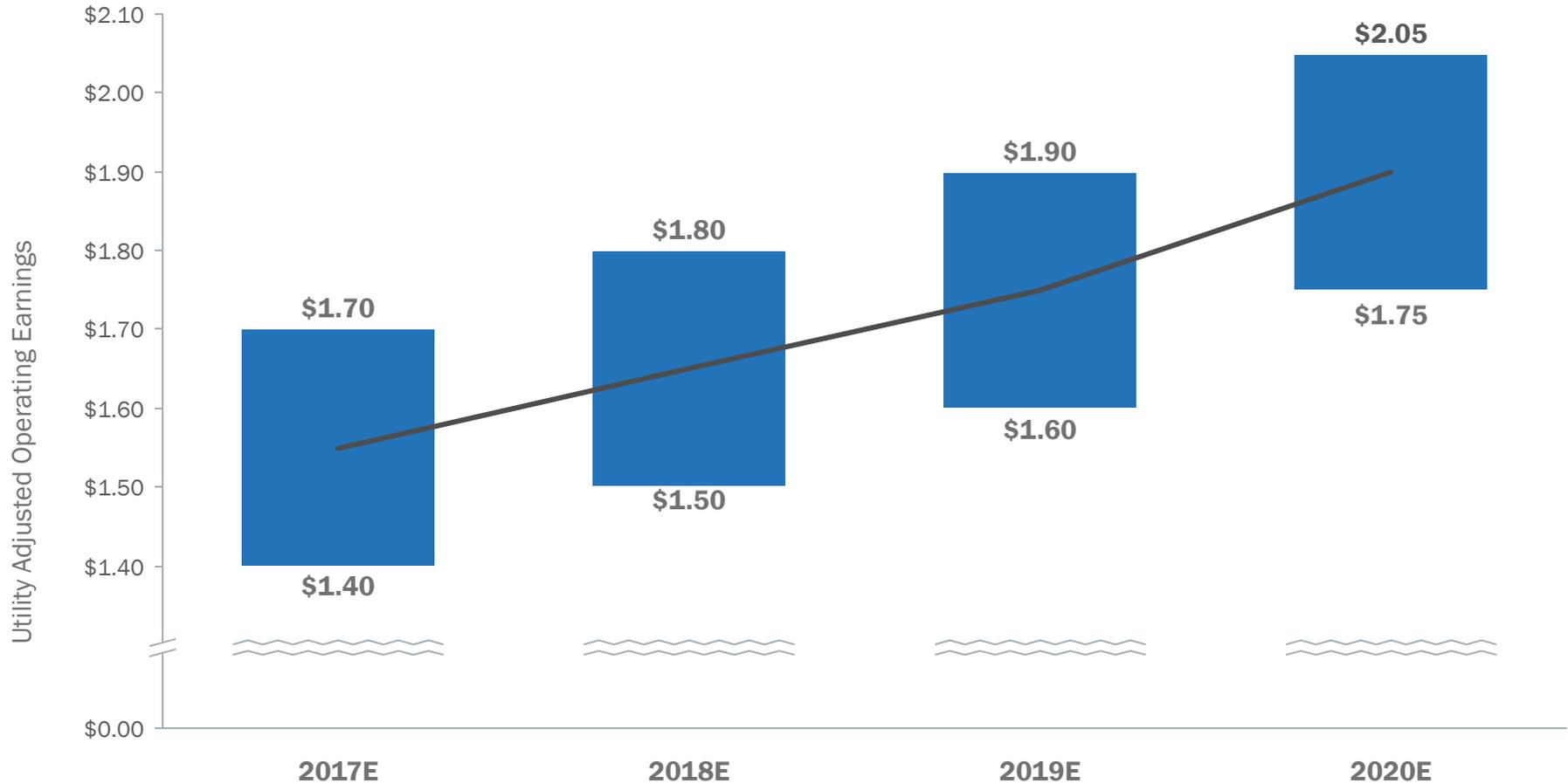
(2) Amounts represents the Illinois Commerce Commission's approved revenue requirement amount in the December 6<sup>th</sup> Final Order. The ICC also ordered rehearing on one narrow topic that ComEd expects to result in a further reduction to the revenue requirement of \$17.5M.

(3) On July 29, 2016, BGE received a PSC order on rehearing, which is reflected in the revenue requirement increase

(4) ComEd Authorized ROE is tied to the 30 year Treasury yield plus 580bps

# Exelon Utilities EPS Growth of 6-8% to 2020

## Exelon Utilities Operating Earnings 2017-2020



### Rate base growth combined with PHI ROE improvement drives EPS growth

Note: Reflects GAAP operating earnings except for 2017. 2017 GAAP EPS range would be \$1.35 to \$1.65. 2017 adjusted (non-GAAP) operating earnings include adjustments to exclude \$0.05 for merger commitments and integration costs. Includes after-tax interest expense held at Corporate for debt associated with existing utility investment.



## Exelon Generation: Gross Margin Update

Gross Margin Category (\$M) <sup>(1)</sup>	December 31, 2016			Change from Sep 30, 2016 <sup>(7)</sup>		
	2017	2018	2019	2017	2018	2019
Open Gross Margin <sup>(3)</sup> (including South, West, Canada hedged gross margin)	\$4,100	\$4,200	\$4,050	\$300	\$550	\$450
Capacity and ZEC Revenues <sup>(3)</sup>	\$1,850	\$2,250	\$2,050	\$400	\$550	\$600
Mark-to-Market of Hedges <sup>(3,4)</sup>	\$1,200	\$450	\$350	-	\$(50)	\$50
Power New Business / To Go	\$550	\$900	\$950	\$(50)	-	-
Non-Power Margins Executed	\$200	\$100	\$50	\$50	-	-
Non-Power New Business / To Go	\$250	\$400	\$450	\$(50)	-	-
<b>Total Gross Margin<sup>(2,5,6)</sup></b>	<b>\$8,150</b>	<b>\$8,300</b>	<b>\$7,900</b>	<b>\$650</b>	<b>\$1,050</b>	<b>\$1,100</b>

### Recent Developments

- Gross Margin disclosure now includes impacts of NY and IL ZECs, pending FitzPatrick acquisition, and reversal of the IL plant closures
- Behind ratable hedging position reflects the fundamental upside we see in power prices
  - Generation ~6-9% open in 2017

1) Gross margin categories rounded to nearest \$50M

2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation and Power businesses. See Slide 50 for a Non-GAAP to GAAP reconciliation of Total Gross Margin.

3) Excludes EDF's equity ownership share of the CENG Joint Venture

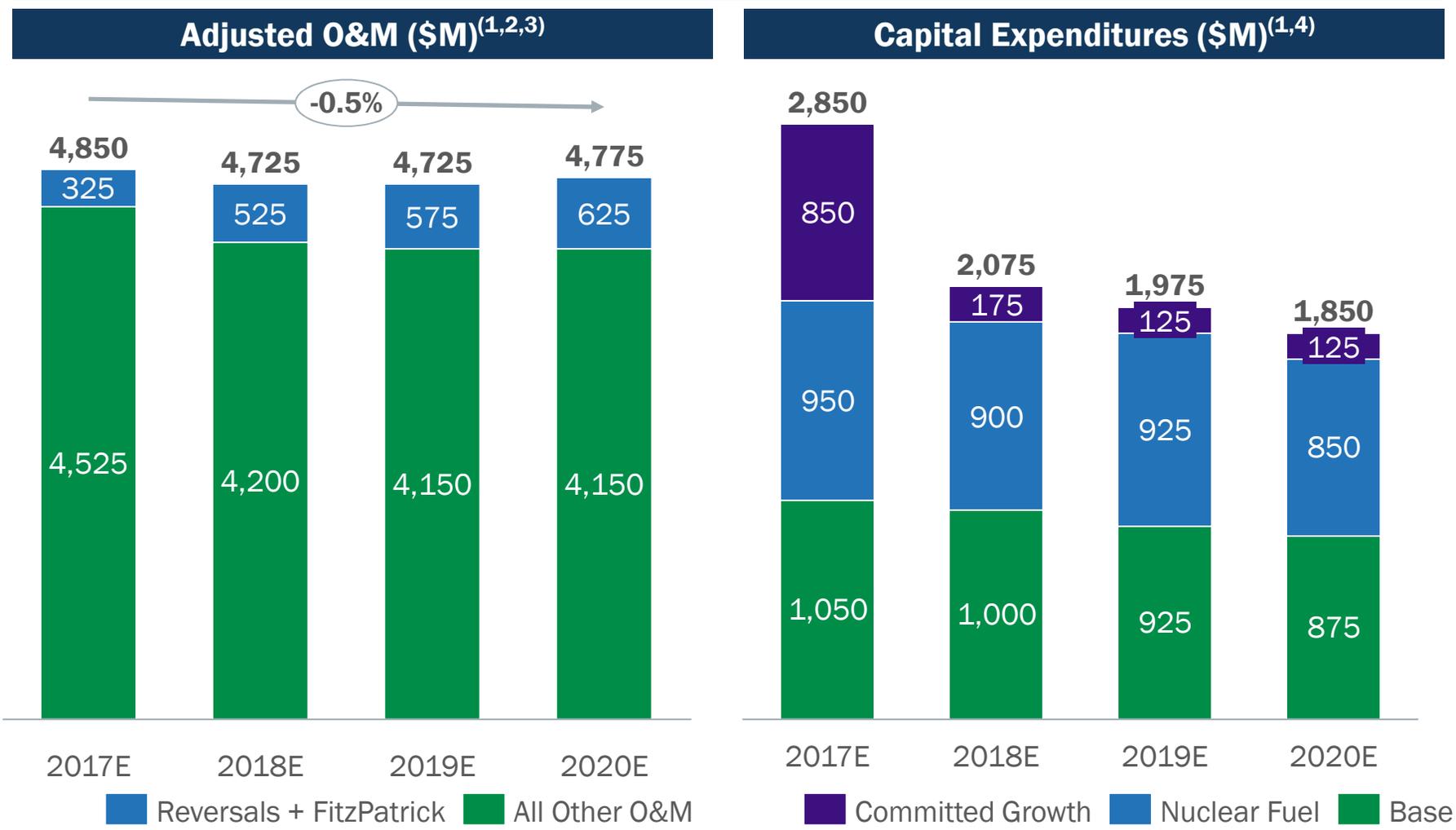
4) Mark-to-Market of Hedges assumes mid-point of hedge percentages

5) Based on December 31, 2016 market conditions

6) Reflects Oyster Creek retirement in December 2019

7) Variance to September 30, 2016 are on a pro-forma basis. See slide 44 for a full pro-forma of the September 30, 2016 gross margin in new format.

# Driving Cost and Capital Out of the Generation Business



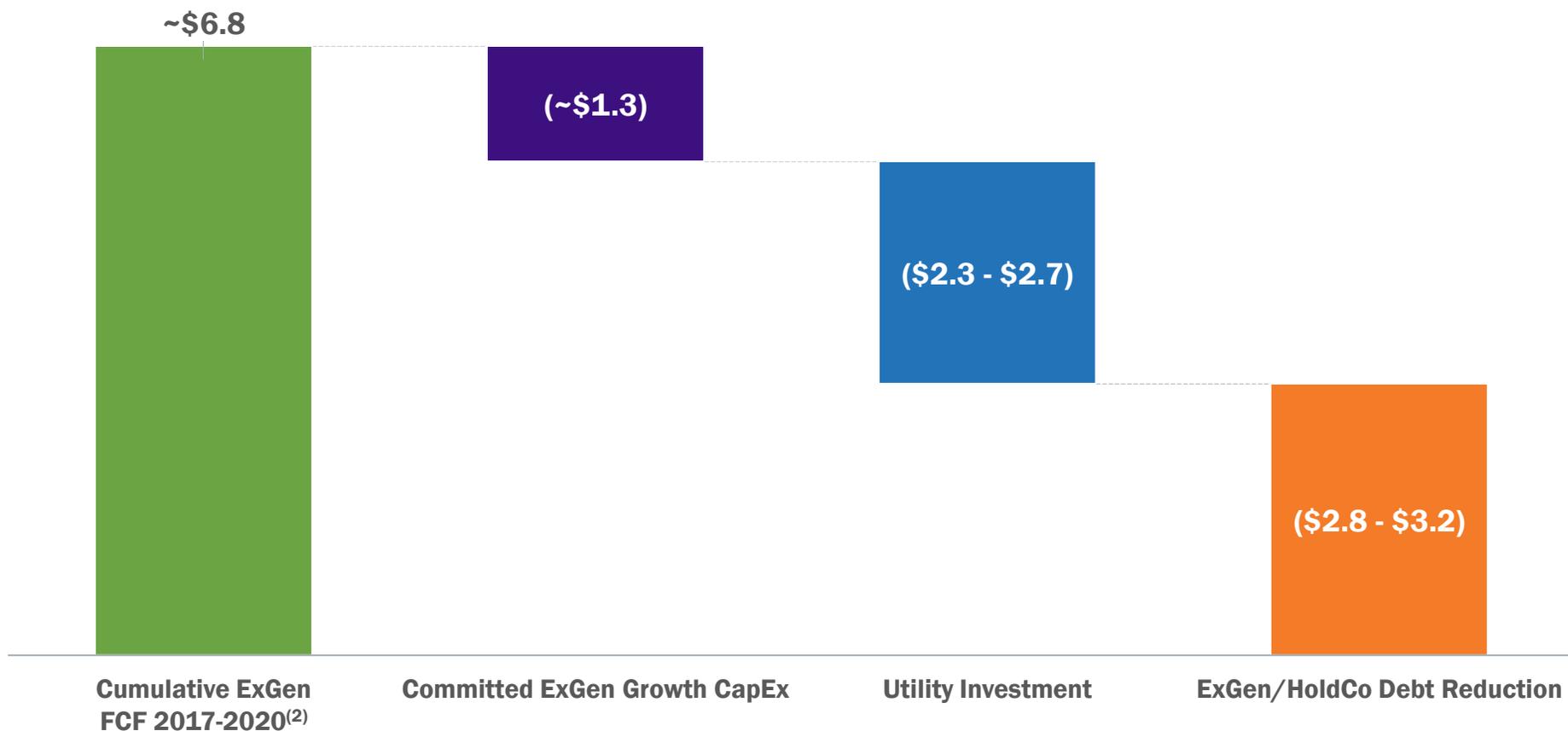
**Negative O&M CAGR reflects benefits of cost optimization program**

(1) All amounts rounded to the nearest \$25M  
 (2) O&M and Capital Expenditures reflect reversal of Quad Cities and Clinton retirement decisions and includes FitzPatrick  
 (3) Refer to slide 77 in the Appendix for a reconciliation of adjusted (non-GAAP) O&M to GAAP O&M  
 (4) Capital spend represents cash CapEx with CENG at 100% and excludes merger commitments; incremental CapEx (Base and Fuel) impact from nuclear reversals and adding FitzPatrick for 2017, 2018, 2019, and 2020 at Q4 is \$250M, \$300M, \$225M, and \$275M, respectively



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

### 2017-2020 Exelon Generation Free Cash Flow<sup>(1)</sup> and Uses of Cash (\$B)



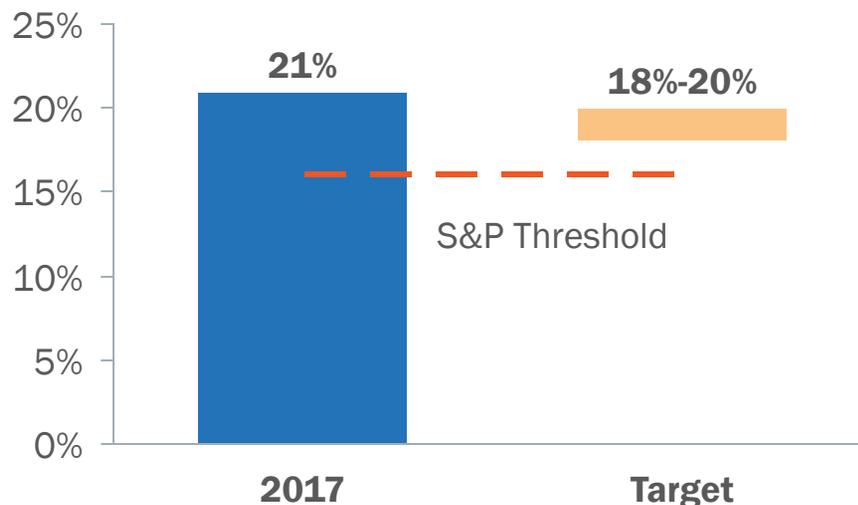
### Redeploying Exelon Generation’s free cash flow to maximize shareholder value

(1) Free Cash Flow is a non-GAAP Measure. See slide 77 for a reconciliation of free cash flow to the most comparable GAAP measures.  
 (2) Cumulative Free Cash Flow is a midpoint of a range based on December 31, 2016 market prices. Sources include change in margin, tax parent benefit, equity investments, and acquisitions and divestitures.

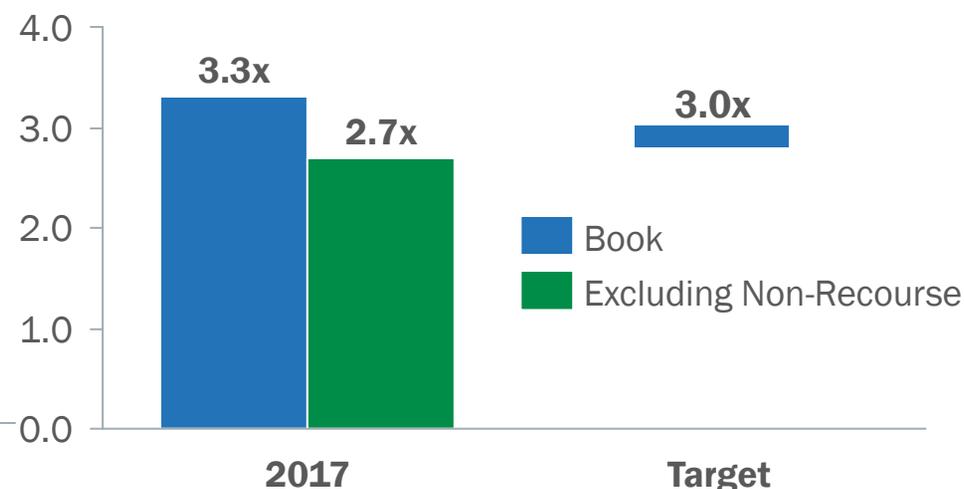


# Maintaining Investment Grade Credit Ratings is a Top Financial Priority

**Exelon S&P FFO/Debt %<sup>(1)(4)</sup>**



**ExGen Debt/EBITDA Ratio<sup>(5)</sup>**



## Credit Ratings by Operating Company

Current Ratings <sup>(2)(3)</sup>	ExCorp	ExGen	ComEd	PECO	BGE	ACE	DPL	Pepco
<b>Moody's</b>	Baa2	Baa2	A2	Aa3	A3	A3	A2	A2
<b>S&amp;P</b>	BBB-	BBB	A-	A-	A-	A	A	A
<b>Fitch</b>	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. FFO/Debt is a non-GAAP measure. Please refer to slide 73 in the appendix for a reconciliation of FFO/Debt to the most comparable GAAP measure.

(2) Current senior unsecured ratings as of December 31, 2016 for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco

(3) Moody's has ComEd on "Positive" outlook. All other ratings have "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. EBITDA, a non-GAAP measure, is defined as earnings before interest, taxes, depreciation and amortization. Includes nuclear fuel amortization expense. Please refer to slide 74 in the appendix for a reconciliation of Debt/EBITDA to the most comparable GAAP measure.



## The Exelon Value Proposition

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- **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<sup>(1)</sup>,
  - Debt reduction; and,
  - Modest contracted generation investments

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

# Additional Disclosures

## Key Provisions of the Future Energy Jobs Bill

- **Zero Emission Standard:** Requires the Illinois Power Agency to procure contracts with zero emission facilities for zero emission credits (ZECs) equal to 16% of the actual electricity delivered in 2014. Cost of the program is capped at 1.65% of rates (about \$235 million per year) for 10-year program duration and payments may be reduced by up to 10% if certain customer cost caps are exceeded.
  - ZEC payment calculation (subject to the caps):



- **Energy Efficiency:** ComEd will increase spending to ~\$400M at the peak of the program. This spending will be treated as traditional asset investment and ComEd will be able to earn a return on it.
- **Formula Rate:** Extends the ComEd Distribution formula rate until 2022
- **Decoupling:** Revenue is decoupled from energy usage by eliminating the +/- 50 basis point collar in the formula rate
- **Renewable Portfolio Standard:** RPS is restructured to generate more renewable development, particularly, the law allows ComEd to propose developing a low-income community solar project and also will fund and place in rate base a solar rebate program for commercial and community solar developers
- **Overall Cost Caps:** Creates separate cost caps for residential, C&I, and large C&I customers that limit potential increases due to investment as a result of the legislation. Sets forth processes and remedies if projected or actual costs exceed the limitations specified in the legislation for the relevant customer class.

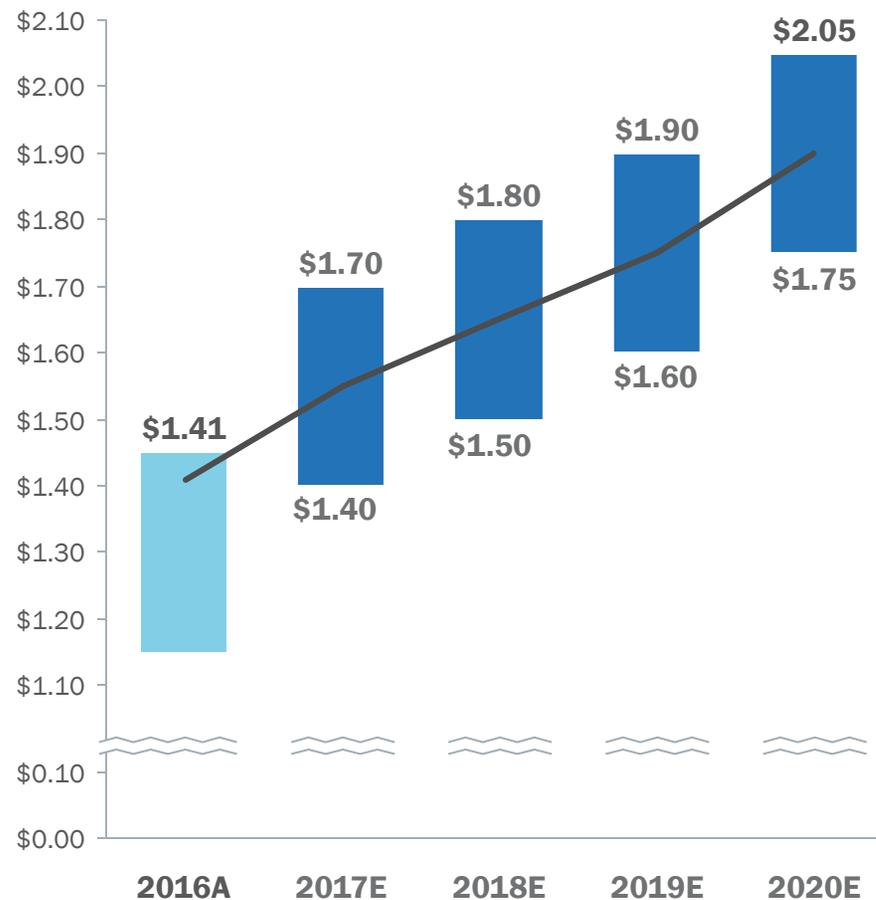
(1) Social cost of carbon remains flat for first six years and then escalates at \$1/MWh per year thereafter

# Exelon Utilities EPS Growth of 6-8% from 2017-2020

## Analyst Day



## Q4 Earnings



## Utility growth rate is still at 6-8% despite higher earnings in 2017

Note: Analyst day reflects GAAP operating earnings. Q4 Earnings reflects GAAP operating earnings except for 2016A and 2017. For 2016A please refer to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS. 2017 GAAP EPS range would be \$1.35 to \$1.65. 2017 adjusted (non-GAAP) operating earnings include adjustments to exclude \$0.05 for merger commitments and integration costs. Includes after-tax interest expense held at Corporate for debt costs associated with utility investment.



# Utility Capex and Rate Base vs. Previous Disclosure

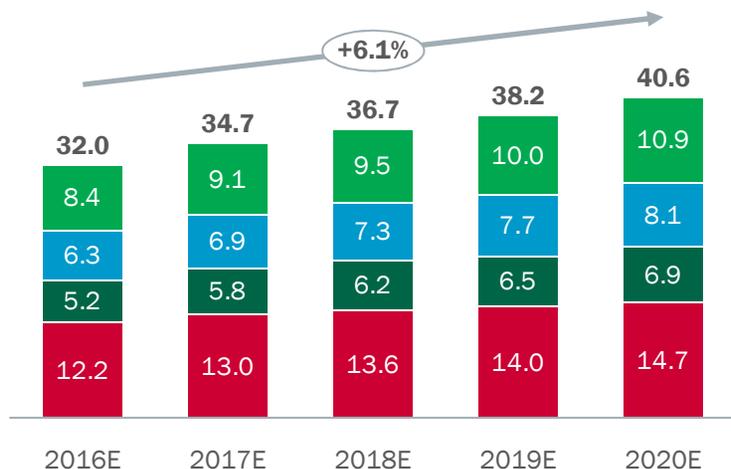
**Analyst Day Rate Base CapEx (\$M)**



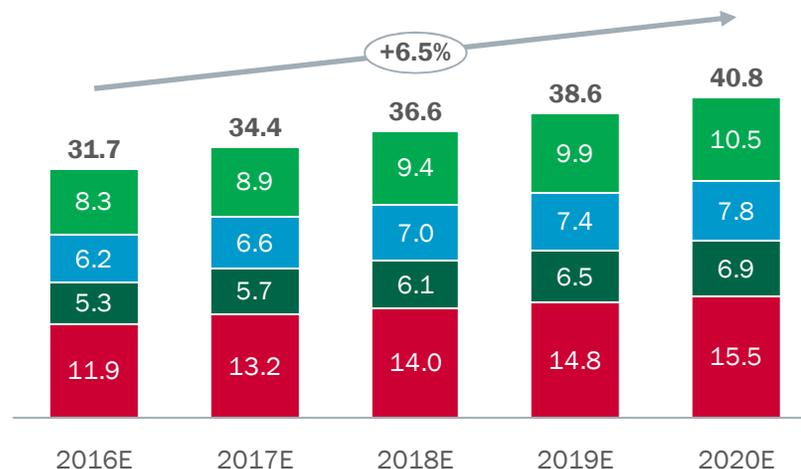
**Q4 2016 CapEx (\$M)**



**Analyst Day Rate Base (\$B)**



**Q4 2016 Rate Base (\$B)**



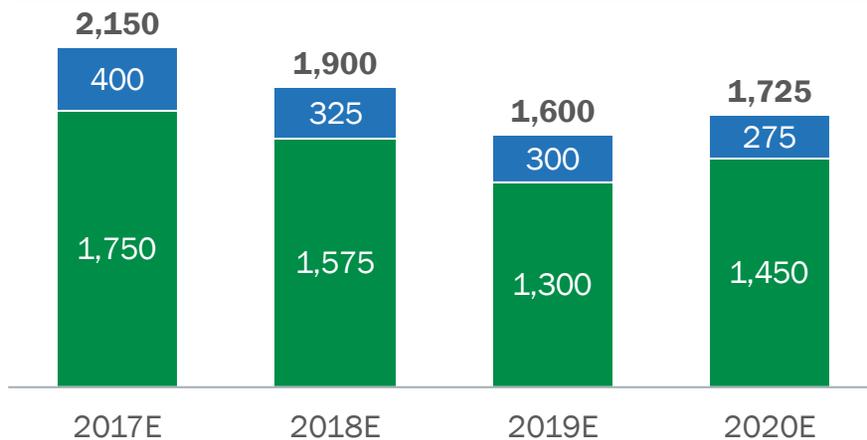
**Over \$20B of capital is being invested in utilities from 2017-2020 and rate base is growing at 6.5% from 2016-2020**

Note: Numbers rounded to nearest \$25M and may not add due to rounding. Rate base reflects year-end estimates.



# ComEd Capital Expenditure and Rate Base Forecast

**Analyst Day Capital Expenditures (\$M)**



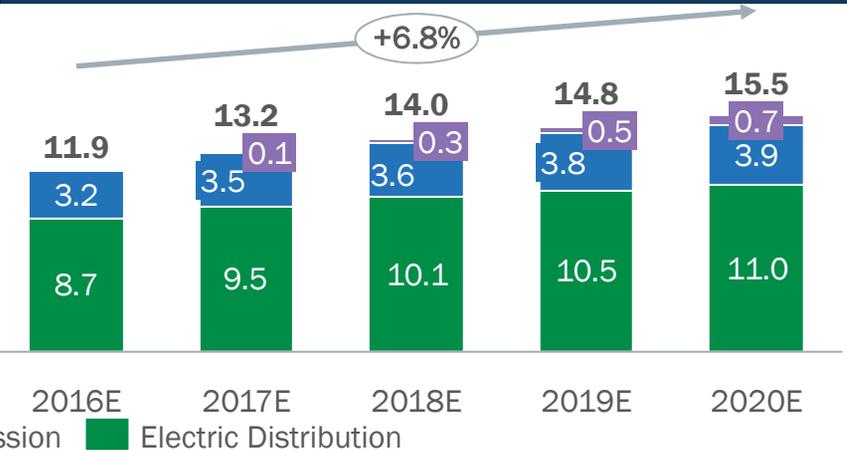
**Q4 2016 Capital Expenditures (\$M)**



**Analyst Day Rate Base (\$B)**



**Q4 2016 Rate Base (\$B)<sup>(2)</sup>**



**~\$7.7B of Capital being invested from 2017-2020**

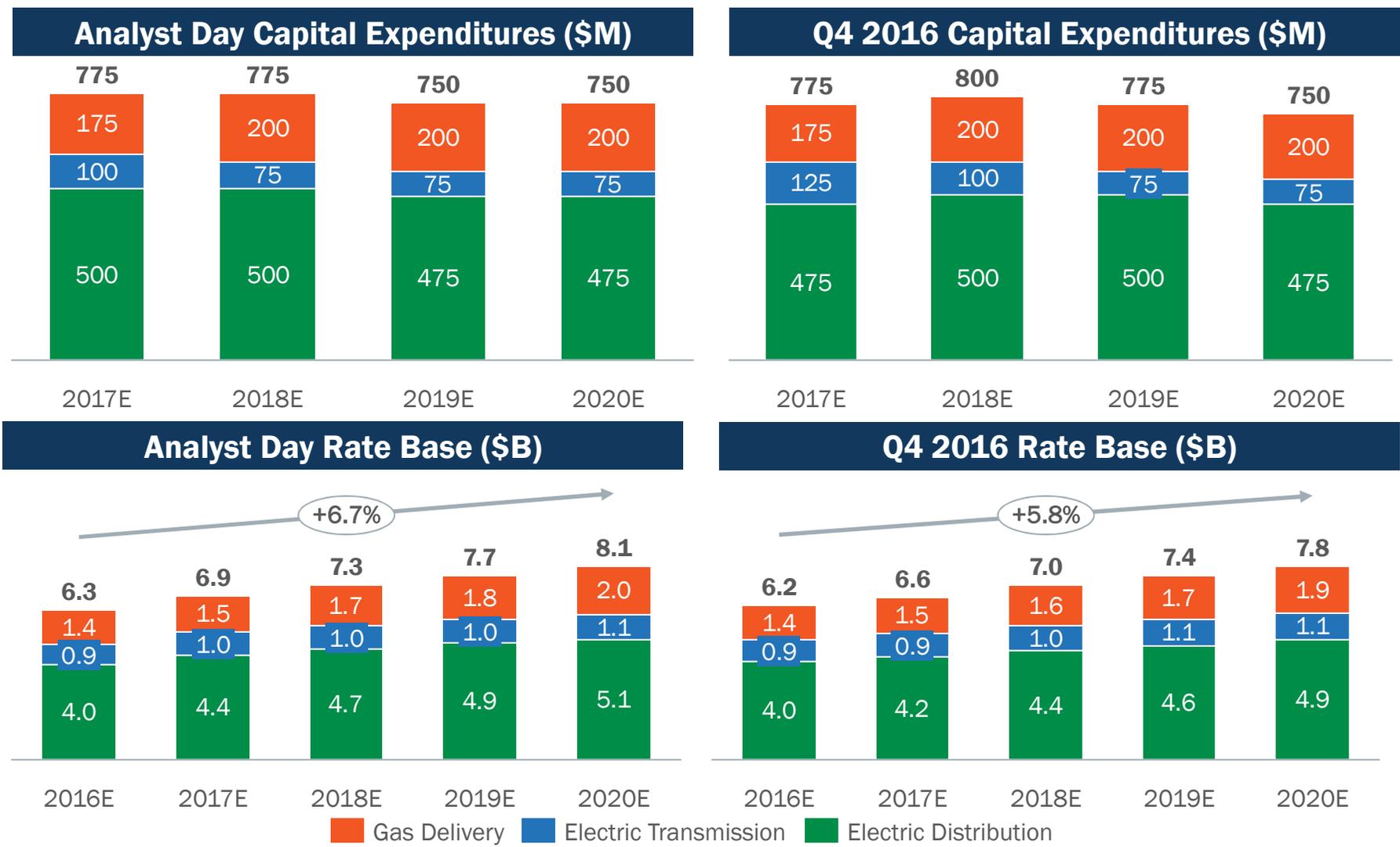
Note: Numbers rounded to nearest \$25M and may not add due to rounding

(1) Other includes long-term regulatory assets, which earn a return consistent with rate base, including Energy Efficiency and the Solar Rebate Program

(2) Rate base reflects year-end estimates



# PECO Capital Expenditure and Rate Base Forecast



**~\$3.1B of Capital being invested from 2017-2020**

Note: Numbers rounded to nearest \$25M and may not add due to rounding. Rate base reflects year-end estimates.



# BGE Capital Expenditure and Rate Base Forecast

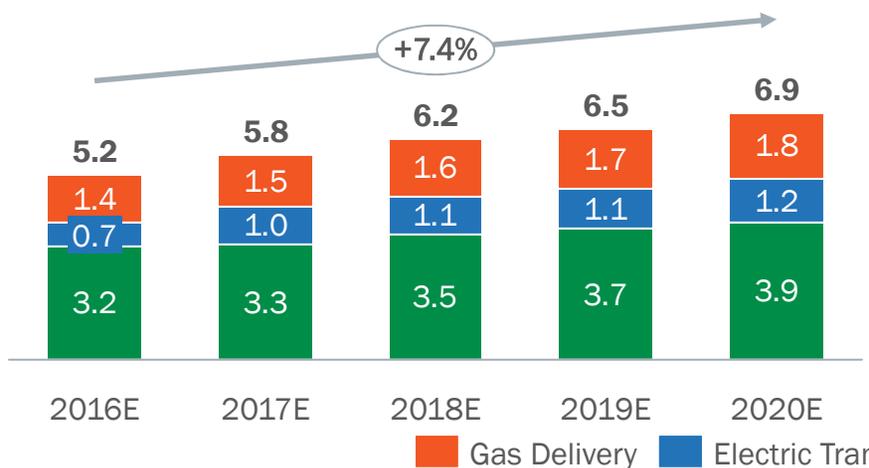
**Analyst Day Capital Expenditures (\$M)**



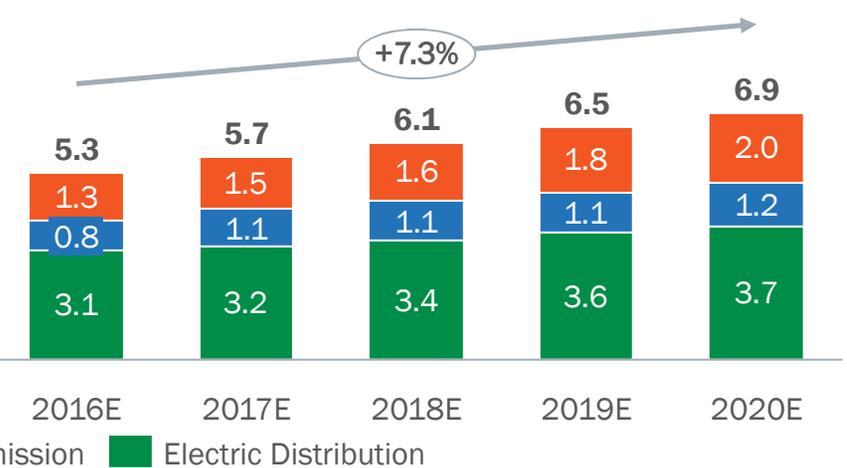
**Q4 2016 Capital Expenditures (\$M)**



**Analyst Day Rate Base (\$B)**



**Q4 2016 Rate Base (\$B)**



Gas Delivery Electric Transmission Electric Distribution

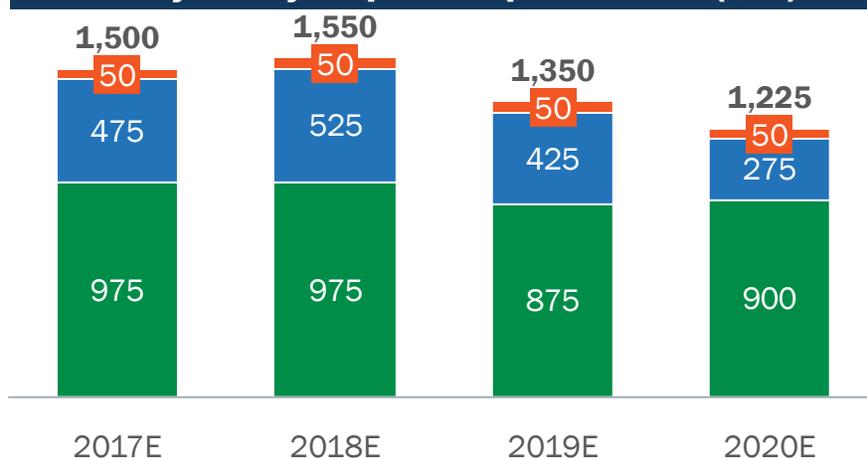
**~\$3.7B of Capital being invested from 2017-2020**

Note: Numbers rounded to nearest \$25M and may not add due to rounding. Rate base reflects year-end estimates.



# PHI Consolidated Capital Expenditure and Rate Base Forecast

**Analyst Day Capital Expenditures (\$M)**



**Q4 2016 Capital Expenditures (\$M)**



**Analyst Day Rate Base (\$B)**



**Q4 2016 Rate Base (\$B)**



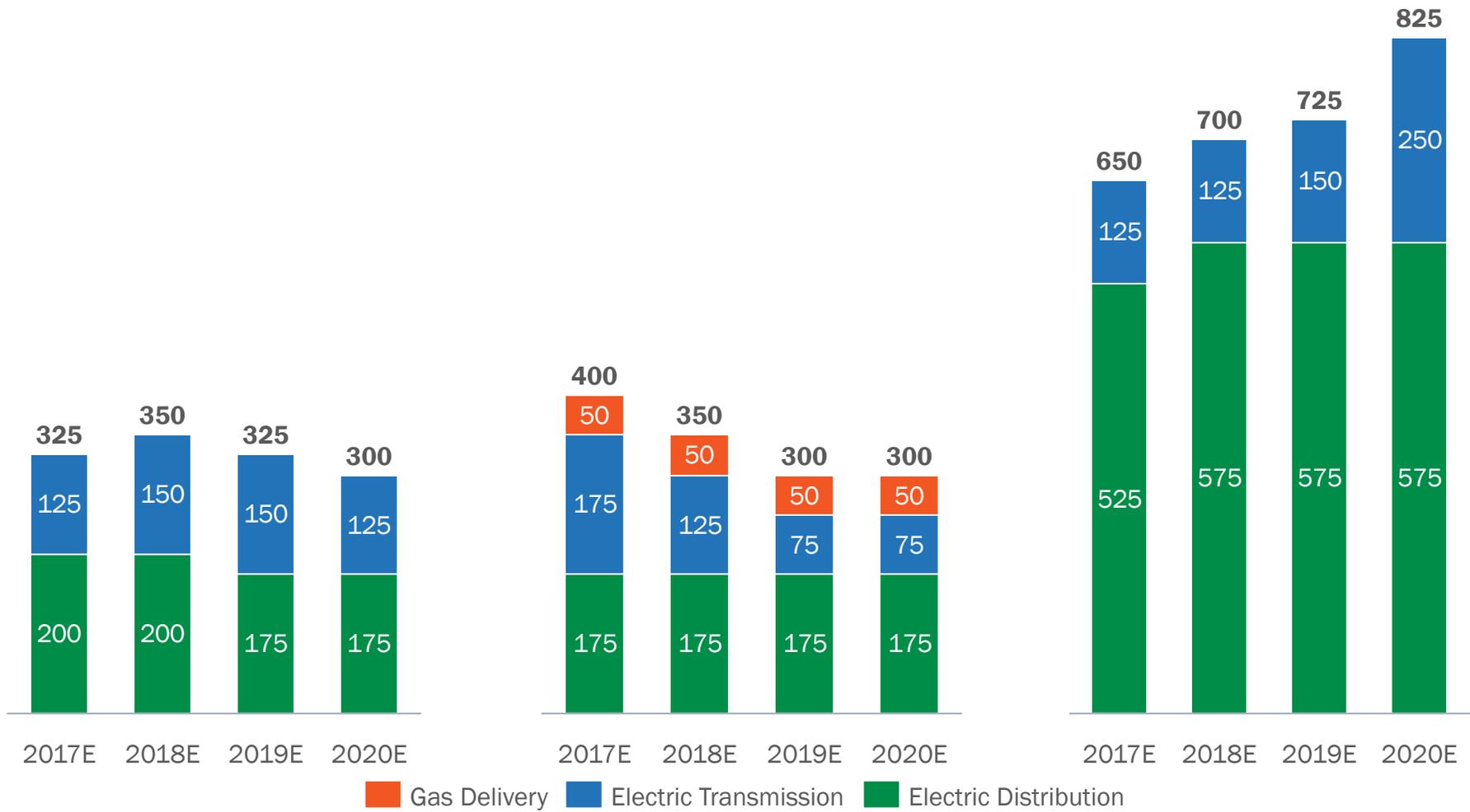
Gas Delivery Electric Transmission Electric Distribution

**~\$5.5B of Capital being invested from 2017-2020**

Note: Numbers rounded to nearest \$25M and may not add due to rounding. Rate base reflects year-end estimates.

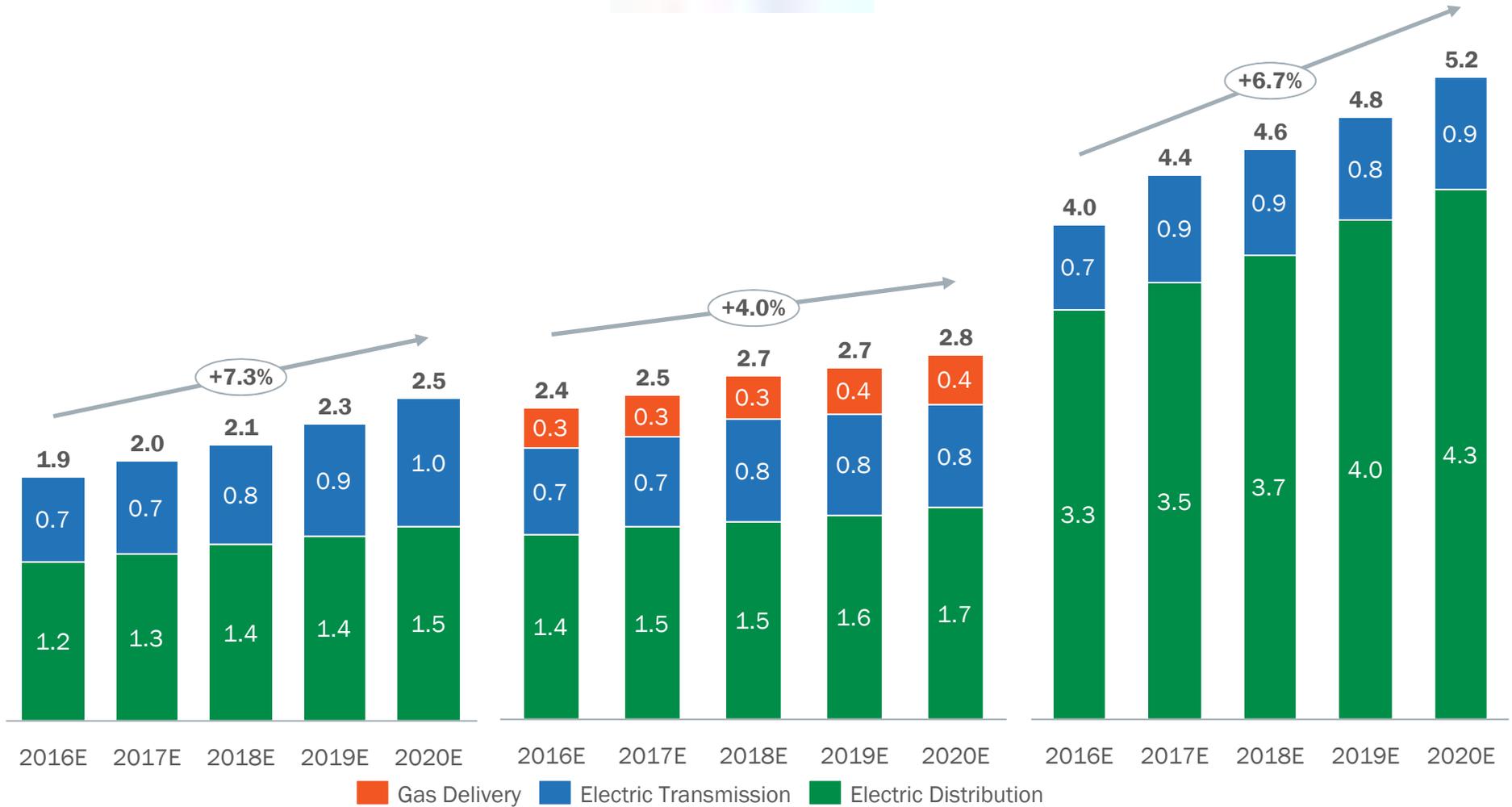


# Pepco Holdings Capital Expenditures



Note: Numbers rounded to nearest \$25M and may not add due to rounding

# Pepco Holdings Rate Base Outlook



Note: All numbers denote year-end rate base and may not add due to rounding. Rate base reflects year-end estimates.

# Exelon Utilities Distribution Rate Case Schedule

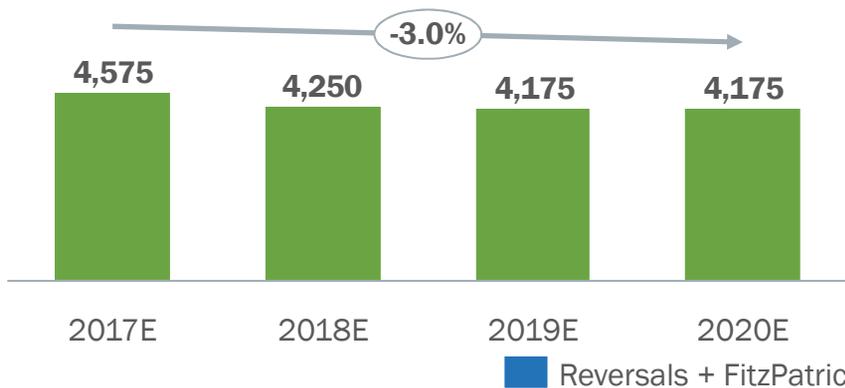
	1/17	2/17	3/17	4/17	5/17	6/17	7/17
<b>ComEd Electric Distribution Formula Rate</b>				2017 FRU Filing Mid-April			Rebuttal Testimony Mid-July
<b>Pepco Electric Distribution Rates - DC</b>		Rebuttal Testimony Feb 1	Evidentiary Hearings Mar 15-21	Final Reply Briefs Apr 24			Commission Order Expected July 25
<b>Delmarva Electric Distribution Rates - DE</b>	Rebuttal Testimony Jan 11		Evidentiary Hearings Mar 7-9				
<b>Delmarva Gas Distribution Rates - DE</b>		Rebuttal Testimony Due Feb 10		Evidentiary Hearings Apr 5-7			
<b>Delmarva Electric Distribution Rates - MD</b>		Commission Order Expected Feb 17					

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

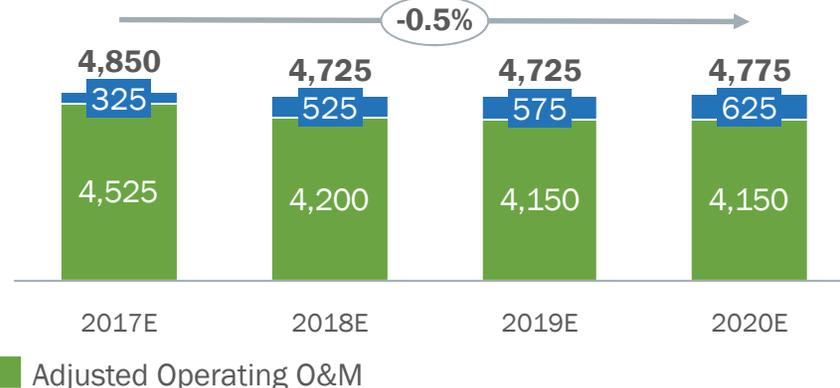


## ExGen O&M and Capex vs. Previous Disclosure

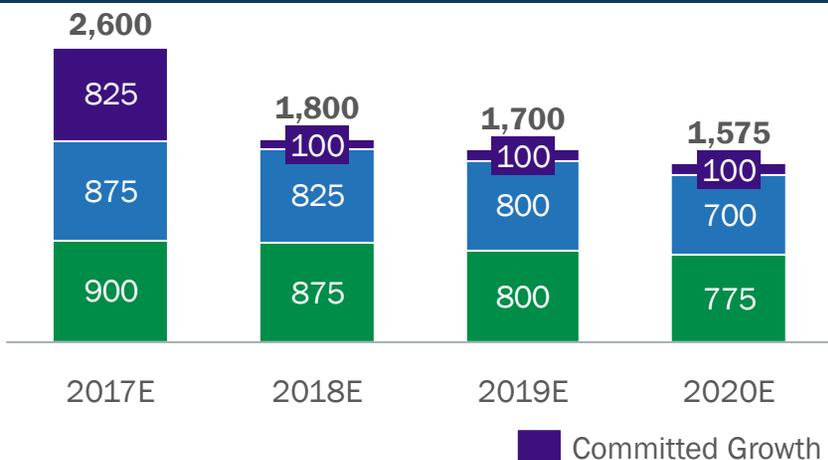
**Adjusted O&M – Q3 2016 (\$M)<sup>(1,2)</sup>**



**Adjusted O&M - Q4 2016 (\$M)<sup>(2)</sup>**



**Capex - Analyst Day (\$M)<sup>(1,3)</sup>**



**Capex - Q4 2016 (\$M)<sup>(3,4)</sup>**

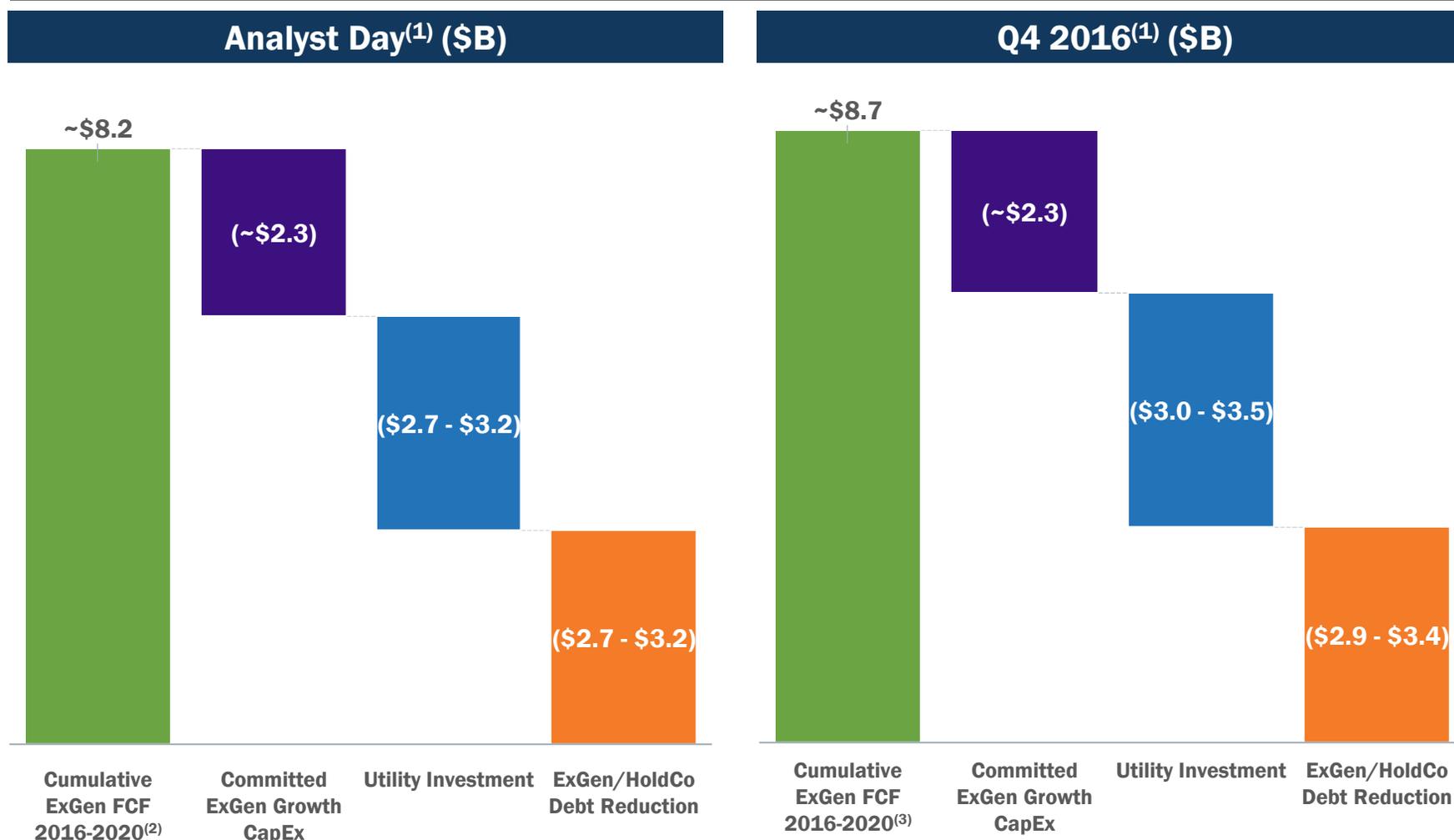


**Capital and O&M now reflect reversal of IL plant closures and addition of FitzPatrick**

- (1) O&M and capital reflect the retirement of Clinton and Quad Cities and does not include cost of FitzPatrick acquisition
- (2) Refer to slide 77 in the appendix for a reconciliation of adjusted (non-GAAP) O&M to GAAP O&M
- (3) Capital spend represents cash CapEx with CENG at 100% and excludes merger commitments
- (4) Incremental CapEx impact of nuclear reversals and adding FitzPatrick for 2017, 2018, 2019, and 2020 at Q4 is \$250M, \$300M, \$225M, and \$275M, respectively



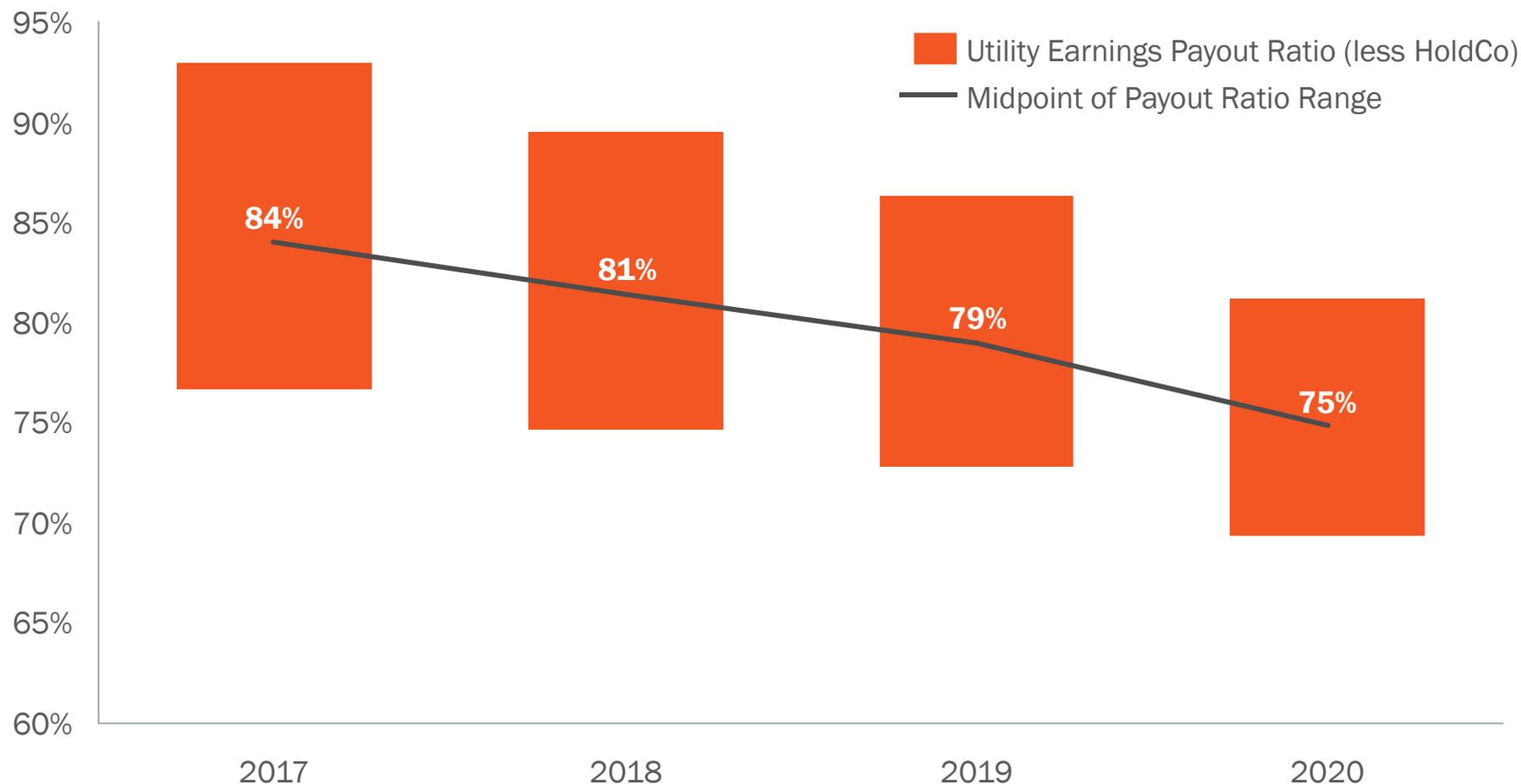
## 2016-2020 Exelon Generation Free Cash Flow and Uses of Cash



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

- (1) Free Cash Flow is a non-GAAP Measure. See slide 77 for a reconciliation of free cash flow to the most comparable GAAP measures.
- (2) Cumulative Free Cash Flow is a midpoint of a range based on June 30, 2016 market prices. It includes sources including change in margin, tax parent benefit, equity investments, and acquisitions and divestitures.
- (3) Cumulative Free Cash Flow is a midpoint of a range based on December 31, 2016 market prices. It includes sources including change in margin, tax parent benefit, equity investments, and acquisitions and divestitures.

## Theoretical Dividend Affordability from Utility less HoldCo<sup>(1,2)</sup>

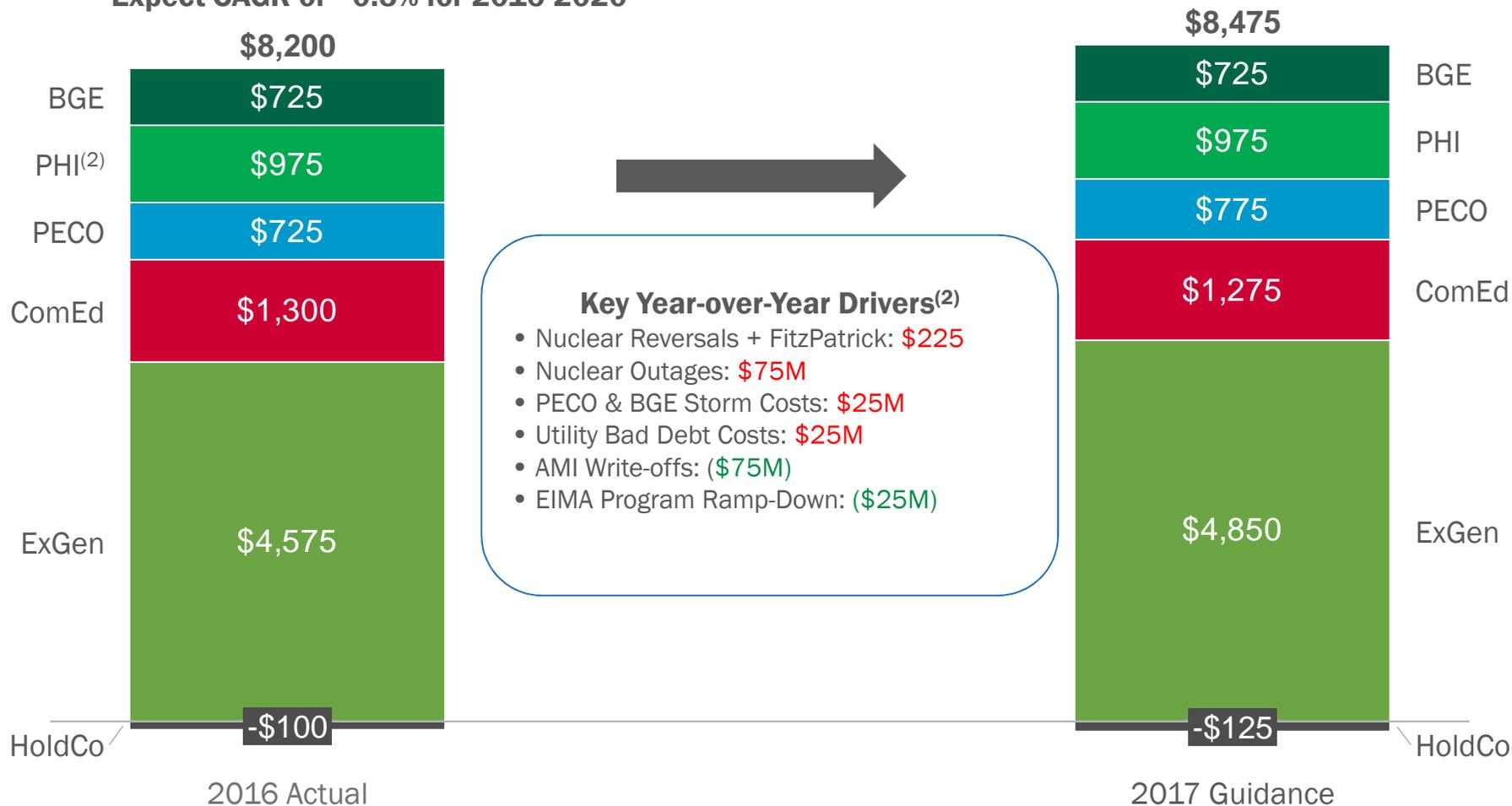


**Utility less HoldCo payout ratio falling consistently even as dividend grows**

- (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 2019 and 2020; this does not signal a change in Board policy at this time. Quarterly dividends are subject to declaration by the board of directors.

# Adjusted O&M Forecast

- 2017 forecast of \$8.5B<sup>(1)</sup>
- Expect CAGR of ~0.5% for 2016-2020



(1) All amounts rounded to the nearest \$25M

(2) Refer to the Appendix for a reconciliation of adjusted (non-GAAP) O&M to GAAP O&M. The Utilities adjusted O&M excludes regulatory O&M costs that are P&L neutral. ExGen adjusted O&M excludes direct cost of sales for certain Constellation businesses, P&L neutral decommissioning costs and the impact from O&M related to variable interest entities.

(3) PHI Adjusted Operating O&M represents full year of spend

## 2017 Projected Sources and Uses of Cash

(\$ in millions) <sup>(1)</sup>	BGE	ComEd	PECO	PHI	Total Utilities	ExGen	Corp <sup>(9)</sup>	Exelon 2017E	Cash Balance	
<b>Beginning Cash Balance<sup>(2)</sup></b>									<b>1,025</b>	(1) All amounts rounded to the nearest \$25M. Figures may not add due to rounding.
Adjusted Cash Flow from Operations <sup>(3,4)</sup>	725	600	725	1,125	3,150	3,625	50	6,825		(2) Gross of posted counterparty collateral
Base CapEx and Nuclear Fuel <sup>(5)</sup>	0	0	0	0	0	(2,050)	(50)	(2,125)		(3) Excludes counterparty collateral activity
<b>Free Cash Flow</b>	<b>725</b>	<b>600</b>	<b>725</b>	<b>1,125</b>	<b>3,150</b>	<b>1,550</b>	<b>0</b>	<b>4,725</b>		(4) Adjusted Cash Flow from Operations (non-GAAP) primarily includes net cash flows from operating activities and net cash flows from investing activities excluding capital expenditures, net M&A, and equity investments. Please refer to slide 76 for reconciliations to GAAP cash flow measures.
Debt Issuances	0	1,050	325	200	1,575	750	1,150	3,475		(5) Figures reflect cash CapEx and CENG fleet at 100%
Debt Retirements	0	(425)	0	(150)	(550)	(700)	(1,700)	(2,950)		(6) Other Financing includes 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 CENG tax distributions to EDF
Project Financing	n/a	n/a	n/a	n/a	n/a	275	n/a	275		(7) ExGen Growth CapEx includes Phoenix, West Medway, AGE, Nuclear relicensing, Nuclear Uprates, and Retail Solar
Equity Issuance/Share Buyback	0	0	0	0	0	0	1,150	1,150		(8) Dividends are subject to declaration by the Board of Directors.
Contribution from Parent	150	700	0	775	1,625	0	(1,625)	0		(9) Includes cash flow activity from Holding Company, eliminations, and other corporate entities
Other Financing <sup>(6)</sup>	225	650	150	(450)	575	150	525	1,250		
<b>Financing</b>	<b>400</b>	<b>1,975</b>	<b>475</b>	<b>375</b>	<b>3,225</b>	<b>475</b>	<b>(500)</b>	<b>3,175</b>		
<b>Total Free Cash Flow and Financing</b>	<b>1,125</b>	<b>2,575</b>	<b>1,200</b>	<b>1,500</b>	<b>6,400</b>	<b>2,025</b>	<b>(525)</b>	<b>7,900</b>		
Utility Investment	(925)	(2,200)	(775)	(1,375)	(5,250)	0	0	(5,250)		
ExGen Growth <sup>(5,7)</sup>	0	0	0	0	0	(850)	0	(850)		
Acquisitions and Divestitures	0	0	0	0	0	50	0	50		
Equity Investments	0	0	0	0	0	(50)	0	(50)		
Dividend <sup>(8)</sup>	0	0	0	0	0	0	(1,225)	(1,225)		
<b>Other CapEx and Dividend</b>	<b>(925)</b>	<b>(2,200)</b>	<b>(775)</b>	<b>(1,375)</b>	<b>(5,250)</b>	<b>(875)</b>	<b>(1,225)</b>	<b>(7,350)</b>		
<b>Total Cash Flow</b>	<b>200</b>	<b>400</b>	<b>425</b>	<b>125</b>	<b>1,150</b>	<b>1,150</b>	<b>(1,750)</b>	<b>550</b>		
<b>Ending Cash Balance<sup>(2)</sup></b>									<b>1,575</b>	

### Consistent and reliable free cash flows

*Operational excellence and financial discipline drives free cash flow reliability*

- ✓ Generating \$4.7B of free cash flow, including \$1.6B at ExGen and \$3.2B at the Utilities

### Supported by a strong balance sheet

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

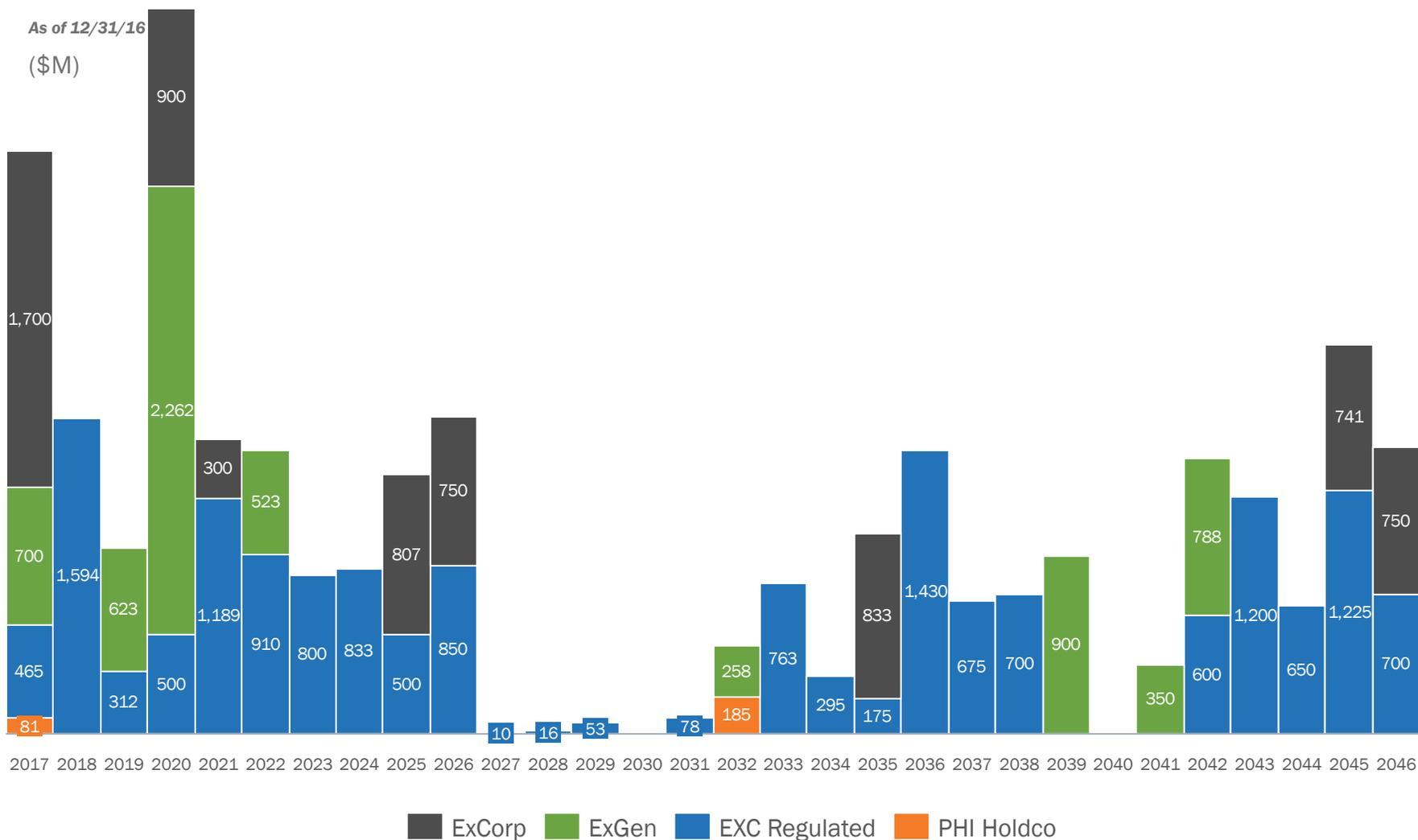
- ✓ ExGen plans to issue \$0.8B of long-term debt to fund dividend to parent to support LKE

### Enable growth & value creation

*Creating value for customers, communities and shareholders*

- ✓ Investing \$6.1B, with \$5.3B at the Utilities and \$0.9B at ExGen

# Exelon Debt Maturity Profile



**Exelon's weighted average LTD maturity is approximately 13 years**

Note: ExCorp debt includes \$1,150M mandatory convertible units remarketing in 2017; ExGen debt includes legacy CEG debt; excludes securitized debt and non-recourse debt

## Pension and OPEB Contributions and Expense

	2016 <sup>(1)</sup>		2017	
<i>(in \$M)</i>	Pre-Tax Expense <sup>(2)</sup>	Contributions	Pre-Tax Expense <sup>(2)</sup>	Contributions
Qualified Pension <sub>(3,4,5)</sub>	\$410	\$310	\$435	\$310
Non-Qualified Pension	20	35	20	25
OPEB <sup>(4,5)</sup>	5	50	(5)	45
<b>Total</b>	<b>\$435</b>	<b>\$395</b>	<b>\$450</b>	<b>\$380</b>

(1) PHI expense is included for the post-merger period (March 24 - December 31, 2016)

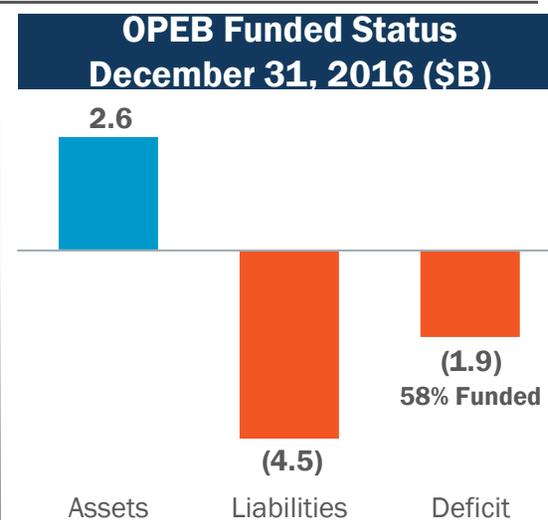
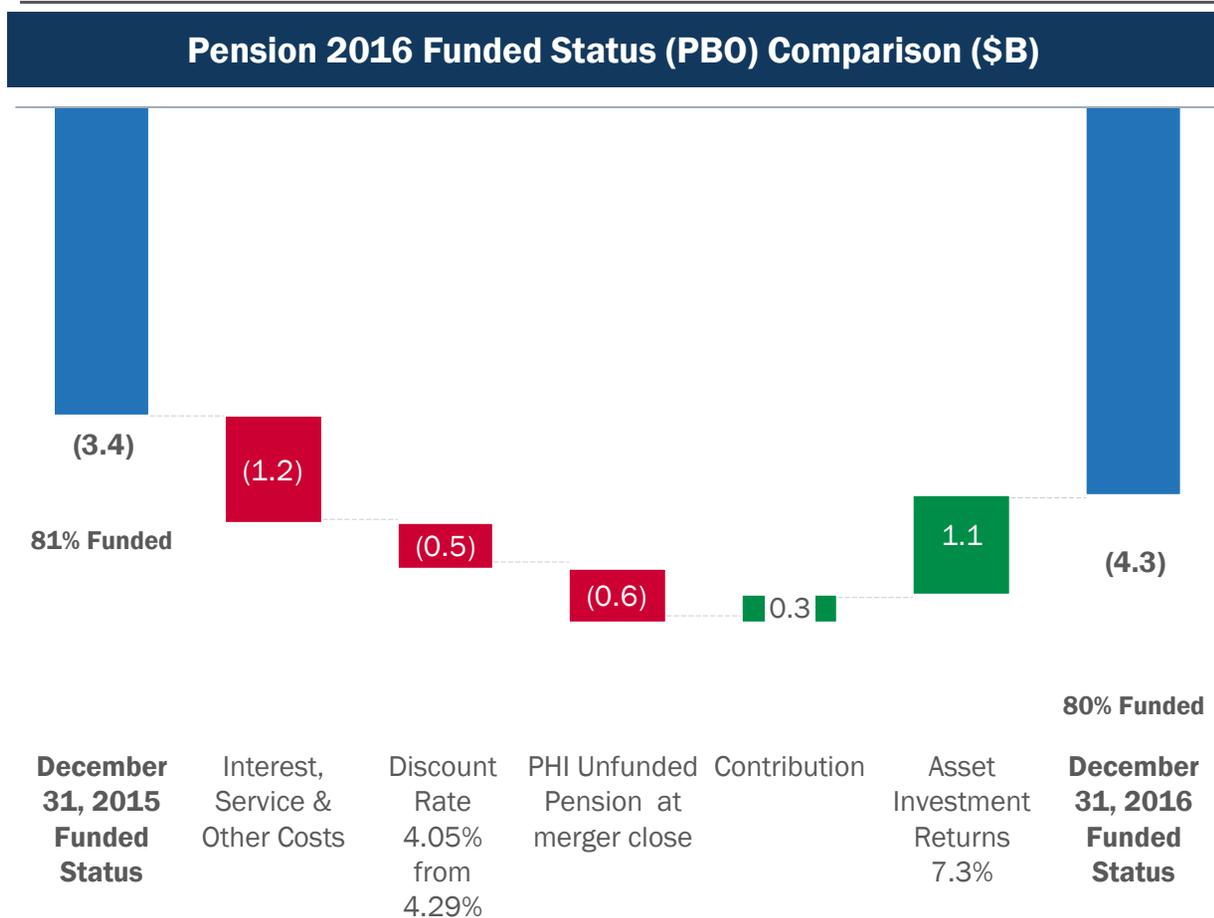
(2) Pension and OPEB expenses assume a 30% and 27% capitalization rate for 2016 and 2017, respectively

(3) The Balanced Funding Strategy for the Qualified Plans provides pension funding of the greater of \$250M or minimum required contributions plus amounts required to avoid benefit restrictions and at-risk status for the legacy Exelon plans. PHI qualified plan contributions are \$60M.

(4) Expected return on assets for pension is 7.00% and for OPEB is 6.70%

(5) Pension and OPEB discount rates are 4.29% for legacy Exelon plans and ~4% for PHI for 2016. Discount rates are 4.04% and ~4.11% for Exelon and PHI, respectively, for 2017.

# Pension and OPEB – Funded Status and Performance



- Based on estimates from Goldman Sachs, the aggregate funded status for pension plans in S&P 500 companies is 82% at the end of 2016
- Exelon is funded status for funding purposes (PPA) is significantly higher than PBO/GAAP funded status, which results in no required material pension contributions over the LRP period

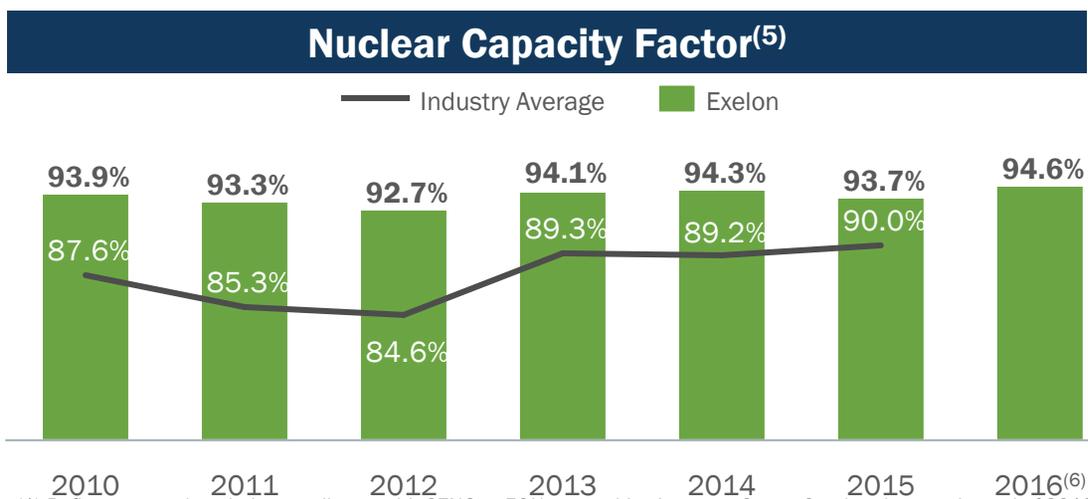
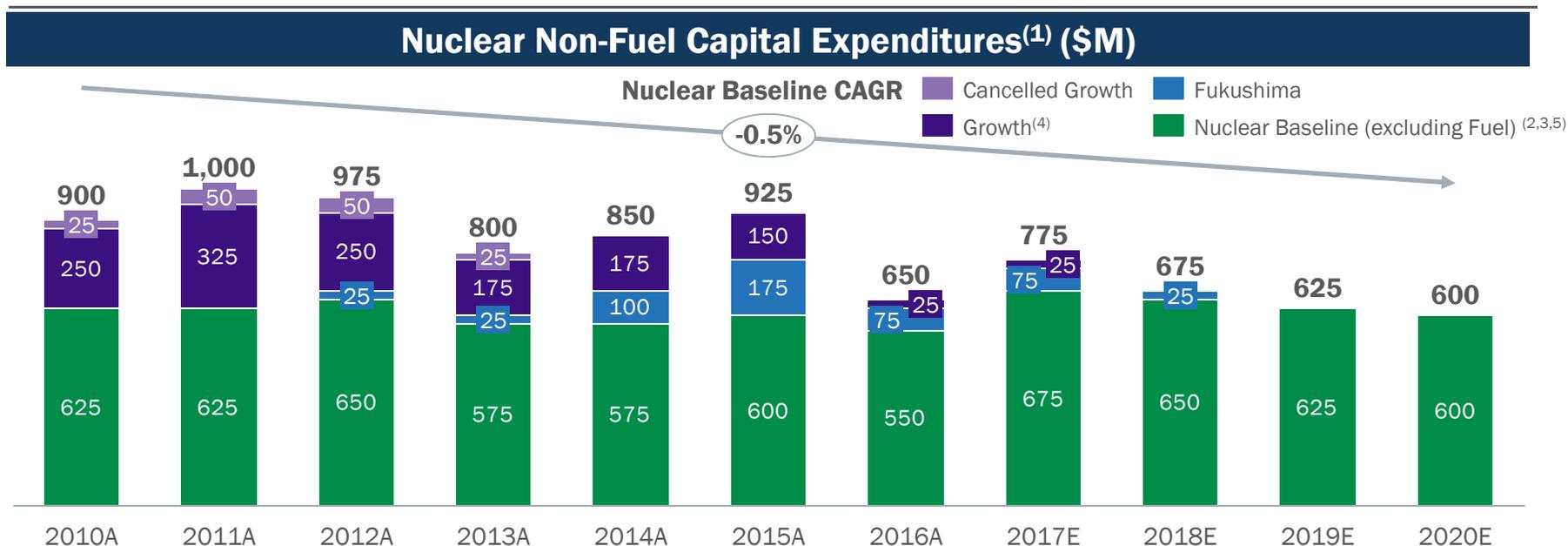
## EPS Sensitivities

	<u>2017</u>	<u>2018</u>	<u>2019</u>	
<b>ExGen EPS Impact<sup>(1,2)</sup></b>	Henry Hub Natural Gas			
	+\$1/MMBtu	\$0.02	\$0.16	\$0.22
	-\$1/MMBtu	\$0.02	(\$0.14)	(\$0.20)
	NiHub ATC Energy Price			
	+\$5/MWh	\$0.03	\$0.16	\$0.23
	-\$5/MWh	(\$0.03)	(\$0.16)	(\$0.23)
	PJM-W ATC Energy Price			
	+\$5/MWh	\$0.00	\$0.05	\$0.12
	-\$5/MWh	\$0.00	(\$0.06)	(\$0.12)
<b>ComEd EPS Impact</b>	<b>30 Year Treasury Rate</b>			
	+50 basis points	\$0.02	\$0.02	\$0.03
	-50 basis points	(\$0.02)	(\$0.02)	(\$0.03)
Share Count ( <i>millions</i> )	949	968	972	
Effective Tax Rate	~34%	~34%	~33%	

(1) Based on December 31, 2016 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 EPS impact calculated by aggregating individual sensitivities may not be equal to the EPS impact calculated when correlations between the various assumptions are also considered.

(2) Represents adjusted (non-GAAP) operating earnings. Refer to slide 72 for a list of adjustments from GAAP EPS to adjusted (non-GAAP) operating earnings.

# Historical Nuclear Capital Investment



Significant historical investments have mitigated asset management issues and prepared sites for license extensions already received, reducing future capital needs. In addition, internal cost initiatives have found more cost efficient solutions to large CapEx spend, such as leveraging reverse engineering replacements rather than large system wide modifications, resulting in baseline CAGR of -0.5%, even with net addition of 3 sites.

(1) Reflects accrual capital expenditures with CENG at 50% ownership. Assumes Oyster Creek retirement by end of 2019. All numbers rounded to \$25M. (2) Baseline includes ownership share of Salem all years. CENG is included at ownership share starting in 2014 (full year) (3) FitzPatrick included starting in 2017 (9 months only) (4) Growth represents capital that increases the capacity of the units (e.g., turbine upgrades, power uprates), and capital that extends the license of a site (e.g., License Renewals) (5) Includes CENG beginning in April 2014, excludes Salem and Fort Calhoun (6) 2016 industry average excluding Exelon was not available at time of publication



# Exelon Generation Disclosures

**December 31, 2016**

# Portfolio Management Strategy

**Strategic Policy Alignment**

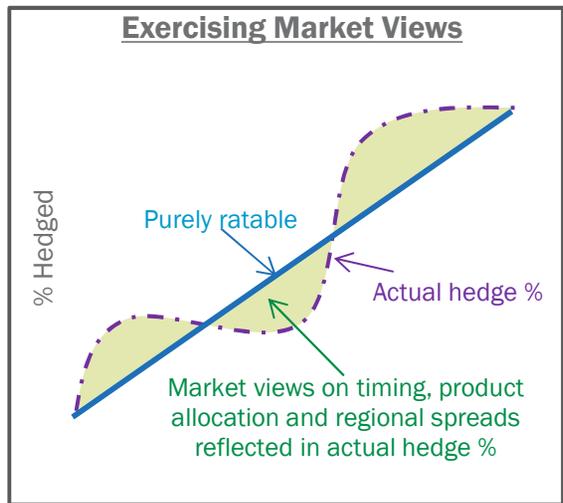
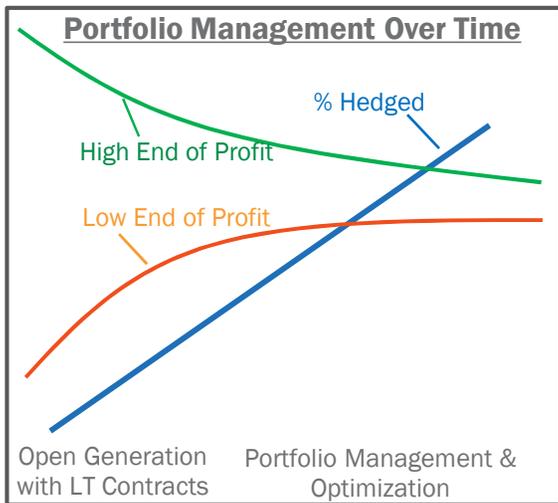
- Aligns hedging program with financial policies and financial outlook
- Establish minimum hedge targets to meet financial objectives of the company (dividend, credit rating)
- Hedge enough commodity risk to meet future cash requirements under a stress scenario

**Three-Year Ratable Hedging**

- 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

**Bull / Bear Program**

- 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

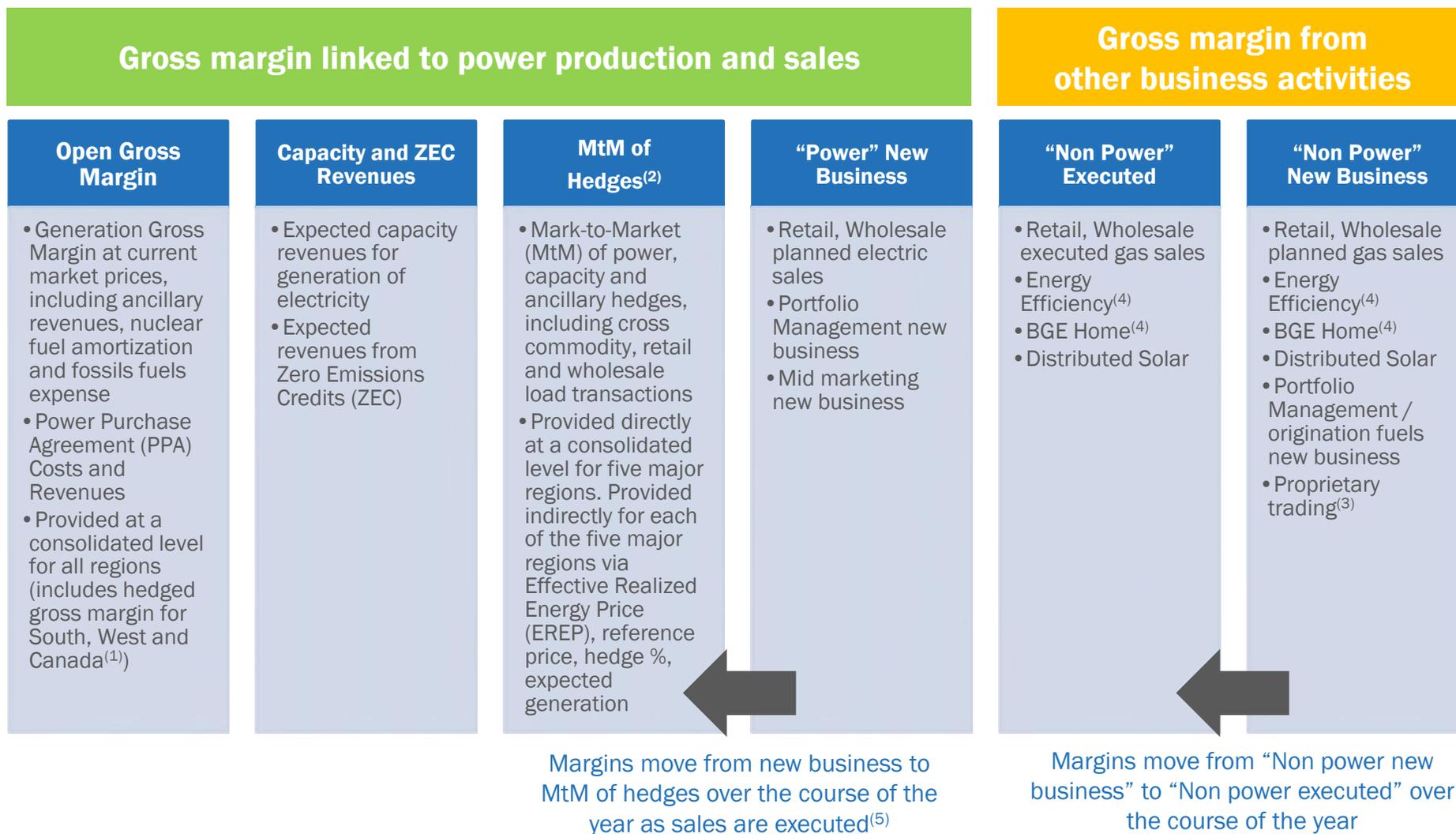


**Protect Balance Sheet**

**Ensure Earnings Stability**

**Create Value**

# Components of Gross Margin Categories



(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) <sup>(1)</sup>	December 31, 2016			September 30, 2016			Change from Sep 30, 2016		
	2017	2018	2019				2017	2018	2019
Open Gross Margin <sup>(3)</sup> (including South, West, Canada hedged gross margin)	\$4,100	\$4,200	\$4,050	\$3,800	\$3,650	\$3,600	\$300	\$550	\$450
Capacity and ZEC Revenues <sup>(3)</sup>	\$1,850	\$2,250	\$2,050	\$1,450	\$1,700	\$1,450	\$400	\$550	\$600
Mark-to-Market of Hedges <sup>(3,4)</sup>	\$1,200	\$450	\$350	\$1,200	\$500	\$300	-	\$(50)	\$50
Power New Business / To Go	\$550	\$900	\$950	\$600	\$900	\$950	\$(50)	-	-
Non-Power Margins Executed	\$200	\$100	\$50	\$150	\$100	\$50	\$50	-	-
Non-Power New Business / To Go	\$250	\$400	\$450	\$300	\$400	\$450	\$(50)	-	-
<b>Total Gross Margin <sup>(2,5,6)</sup></b>	<b>\$8,150</b>	<b>\$8,300</b>	<b>\$7,900</b>	<b>\$7,500</b>	<b>\$7,250</b>	<b>\$6,800</b>	<b>\$650</b>	<b>\$1,050</b>	<b>\$1,100</b>

Reference Prices <sup>(5)</sup>	2017	2018	2019
Henry Hub Natural Gas (\$/MMbtu)	\$3.63	\$3.14	\$2.87
Midwest: NiHub ATC prices (\$/MWh)	\$28.95	\$27.76	\$26.76
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$33.26	\$32.02	\$30.32
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	\$2.51	\$2.48	\$2.73
New York: NY Zone A (\$/MWh)	\$30.93	\$30.63	\$30.37
New England: Mass Hub ATC Spark Spread (\$/MWh) <i>ALQN Gas, 7.5HR, \$0.50 VOM</i>	\$5.68	\$5.93	\$5.03

1) Gross margin categories rounded to nearest \$50M

2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation and Power businesses. See Slide 50 for a Non-GAAP to GAAP reconciliation of Total Gross Margin.

3) Excludes EDF's equity ownership share of the CENG Joint Venture

4) Mark-to-Market of Hedges assumes mid-point of hedge percentages

5) Based on December 31, 2016 market conditions

6) Reflects Oyster Creek retirement in December 2019

## ExGen Disclosures

	Previous Format September 30, 2016			New Format September 30, 2016		
	2017	2018	2019	2017	2018	2019
<b>Gross Margin Category (\$M) <sup>(1)</sup></b>						
Open Gross Margin <sup>(3)</sup> (including South, West, Canada hedged gross margin)	\$5,250	\$5,350	\$5,050	\$3,800	\$3,650	\$3,600
Capacity and ZEC Revenues <sup>(3)</sup>	\$0	\$0	\$0	\$1,450	\$1,700	\$1,450
Mark-to-Market of Hedges <sup>(3,4)</sup>	\$1,200	\$500	\$300	\$1,200	\$500	\$300
Power New Business / To Go	\$600	\$900	\$950	\$600	\$900	\$950
Non-Power Margins Executed	\$150	\$100	\$50	\$150	\$100	\$50
Non-Power New Business / To Go	\$300	\$400	\$450	\$300	\$400	\$450
<b>Total Gross Margin<sup>(2,5,6)</sup></b>	<b>\$7,500</b>	<b>\$7,250</b>	<b>\$6,800</b>	<b>\$7,500</b>	<b>\$7,250</b>	<b>\$6,800</b>

1) Gross margin categories rounded to nearest \$50M

2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation and Power businesses. See Slide 50 for a Non-GAAP to GAAP reconciliation of Total Gross Margin.

3) Excludes EDF's equity ownership share of the CENG Joint Venture

4) Mark-to-Market of Hedges assumes mid-point of hedge percentages

5) Based on December 31, 2016 market conditions

6) Reflects Oyster Creek retirement in December 2019

## ExGen Disclosures

Generation and Hedges	2017	2018	2019
<u>Exp. Gen (GWh)</u> <sup>(1)</sup>	<b>204,800</b>	<b>208,300</b>	<b>211,700</b>
Midwest	95,400	95,900	96,900
Mid-Atlantic <sup>(2,6)</sup>	60,200	60,300	60,000
ERCOT	23,000	28,100	29,100
New York <sup>(2)</sup>	14,500	15,400	16,600
New England	11,700	8,600	9,100
<u>% of Expected Generation Hedged</u> <sup>(3)</sup>	<b>91%-94%</b>	<b>56%-59%</b>	<b>28%-31%</b>
Midwest	88%-91%	47%-50%	21%-24%
Mid-Atlantic <sup>(2,6)</sup>	98%-101%	67%-70%	37%-40%
ERCOT	85%-88%	60%-63%	32%-35%
New York <sup>(2)</sup>	92%-95%	51%-54%	34%-37%
New England	97%-100%	66%-69%	33%-36%
<u>Effective Realized Energy Price (\$/MWh)</u> <sup>(4)</sup>			
Midwest	\$32.00	\$30.00	\$29.50
Mid-Atlantic <sup>(2,6)</sup>	\$43.50	\$38.50	\$40.00
ERCOT <sup>(5)</sup>	\$6.50	\$4.50	\$3.50
New York <sup>(2)</sup>	\$42.00	\$35.00	\$31.50
New England <sup>(5)</sup>	\$15.00	\$6.50	\$6.50

(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 12 in 2019 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 93.4%, 93.3% and 94.5% 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

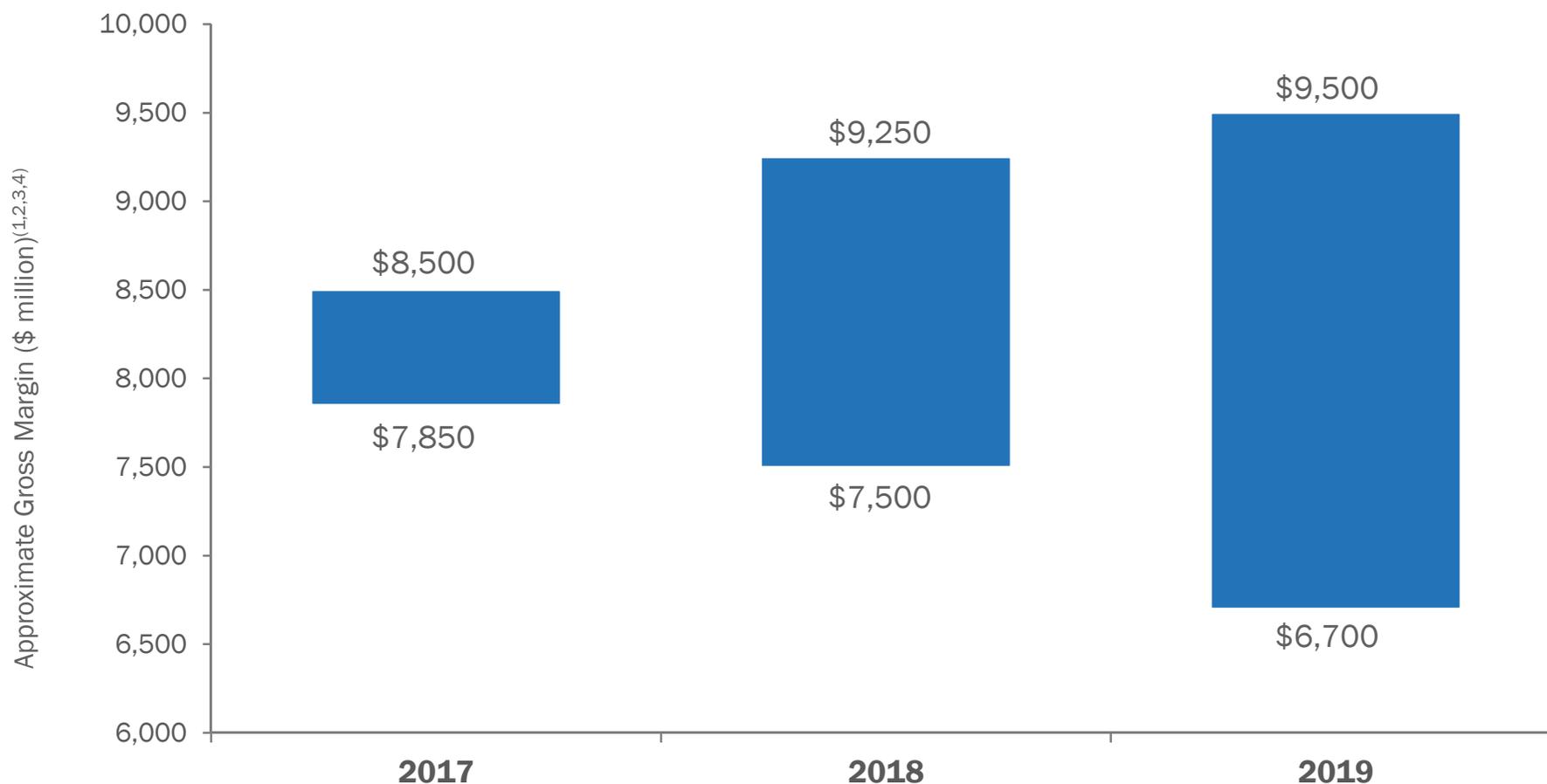
(6) Reflects Oyster Creek retirement in December 2019

## ExGen Hedged Gross Margin Sensitivities

Gross Margin Sensitivities (with Existing Hedges) <sup>(1)</sup>	2017	2018	2019
Henry Hub Natural Gas (\$/Mmbtu)			
+ \$1/Mmbtu	\$35	\$250	\$345
- \$1/Mmbtu	\$25	\$(225)	\$(310)
NiHub ATC Energy Price			
+ \$5/MWh	\$45	\$250	\$360
- \$5/MWh	\$(45)	\$(245)	\$(360)
PJM-W ATC Energy Price			
+ \$5/MWh	\$5	\$85	\$195
- \$5/MWh	\$5	\$(90)	\$(185)
NYPP Zone A ATC Energy Price			
+ \$5/MWh	\$5	\$40	\$50
- \$5/MWh	\$(10)	\$(35)	\$(50)
Nuclear Capacity Factor			
+/- 1%	+/- \$40	+/- \$40	+/- \$35

(1) Based on December 31, 2016 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 prices 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. Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation and Power businesses. Refer to slide 50 for a reconciliation of Total Gross Margin to the most comparable GAAP measure.

## 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 December 31, 2016.
- (2) Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions
- (3) Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation and Power businesses. Excludes EDF's equity ownership share of the CENG Joint Venture. Refer to slide 50 for a reconciliation of Total Gross Margin to the most comparable GAAP measure.
- (4) Reflects Oyster Creek retirement in December 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	←————— \$4.2 billion —————→					
(B)	Capacity and ZEC	←————— \$2.25 billion —————→					
(C)	Expected Generation (TWh)	95.9	60.3	28.1	15.4	8.6	
(D)	Hedge % (assuming mid-point of range)	48.5%	68.5%	61.5%	52.5%	67.5%	
(E=C*D)	Hedged Volume (TWh)	46.5	41.3	17.3	8.1	5.8	
(F)	Effective Realized Energy Price (\$/MWh)	\$30.00	\$38.50	\$4.50	\$35.00	\$6.50	
(G)	Reference Price (\$/MWh)	\$27.76	\$32.02	\$2.48	\$30.63	\$5.93	
(H=F-G)	Difference (\$/MWh)	\$2.24	\$6.48	\$2.02	\$4.37	\$0.57	
(I=E*H)	Mark-to-market value of hedges (\$ million) <sup>(1)</sup>	\$105	\$270	\$35	\$35	\$5	
(J=A+B+I)	Hedged Gross Margin (\$ million)	\$6,900					
(K)	Power New Business / To Go (\$ million)	\$900					
(L)	Non-Power Margins Executed (\$ million)	\$100					
(M)	Non-Power New Business / To Go (\$ million)	\$400					
(N=J+K+L+M)	Total Gross Margin <sup>(2)</sup>	\$8,300 million					

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

(2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation and Power businesses. Refer to slide 50 for a reconciliation of Total Gross Margin to the most comparable GAAP measure.

## Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in \$M) <sup>(1)</sup>	2017	2018	2019
<b>Revenue Net of Purchased Power and Fuel Expense<sup>(2,3)</sup></b>	<b>\$8,850</b>	<b>\$8,975</b>	<b>\$8,575</b>
Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at merger date	\$50	-	-
Other Revenues <sup>(4)</sup>	\$(350)	\$(275)	\$(275)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses <sup>(5)</sup>	\$(400)	\$(400)	\$(400)
<b>Total Gross Margin (Non-GAAP)</b>	<b>\$8,150</b>	<b>\$8,300</b>	<b>\$7,900</b>

Key ExGen Modeling Inputs (in \$M) <sup>(1,6)</sup>	2017
Other Revenues (excluding Gross Receipts Tax) <sup>(4)</sup>	\$200
Adjusted O&M <sup>(7)</sup>	\$(4,850)
Taxes Other Than Income (TOTI) <sup>(8)</sup>	\$(375)
Depreciation & Amortization	\$(1,150)
Interest Expense <sup>(9)</sup>	\$(425)
<b>Effective Tax Rate</b>	<b>32.0%</b>

(1) All amounts rounded to the nearest \$25M

(2) Revenue net of purchased power and fuel expense (RNF), a non-GAAP measure, is calculated as the GAAP measure of operating revenue less the GAAP measure of purchased power and fuel expense. 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 revenues from operating services agreement with Fort Calhoun, variable interest entities, funds collected through revenues for decommissioning the former PECO nuclear plants through regulated rates and gross receipts tax revenues

(5) Reflects the cost of sales of certain Constellation businesses of Generation

(6) ExGen amounts for O&M, TOTI, Depreciation & Amortization; excludes EDF's equity ownership share of the CENG Joint Venture

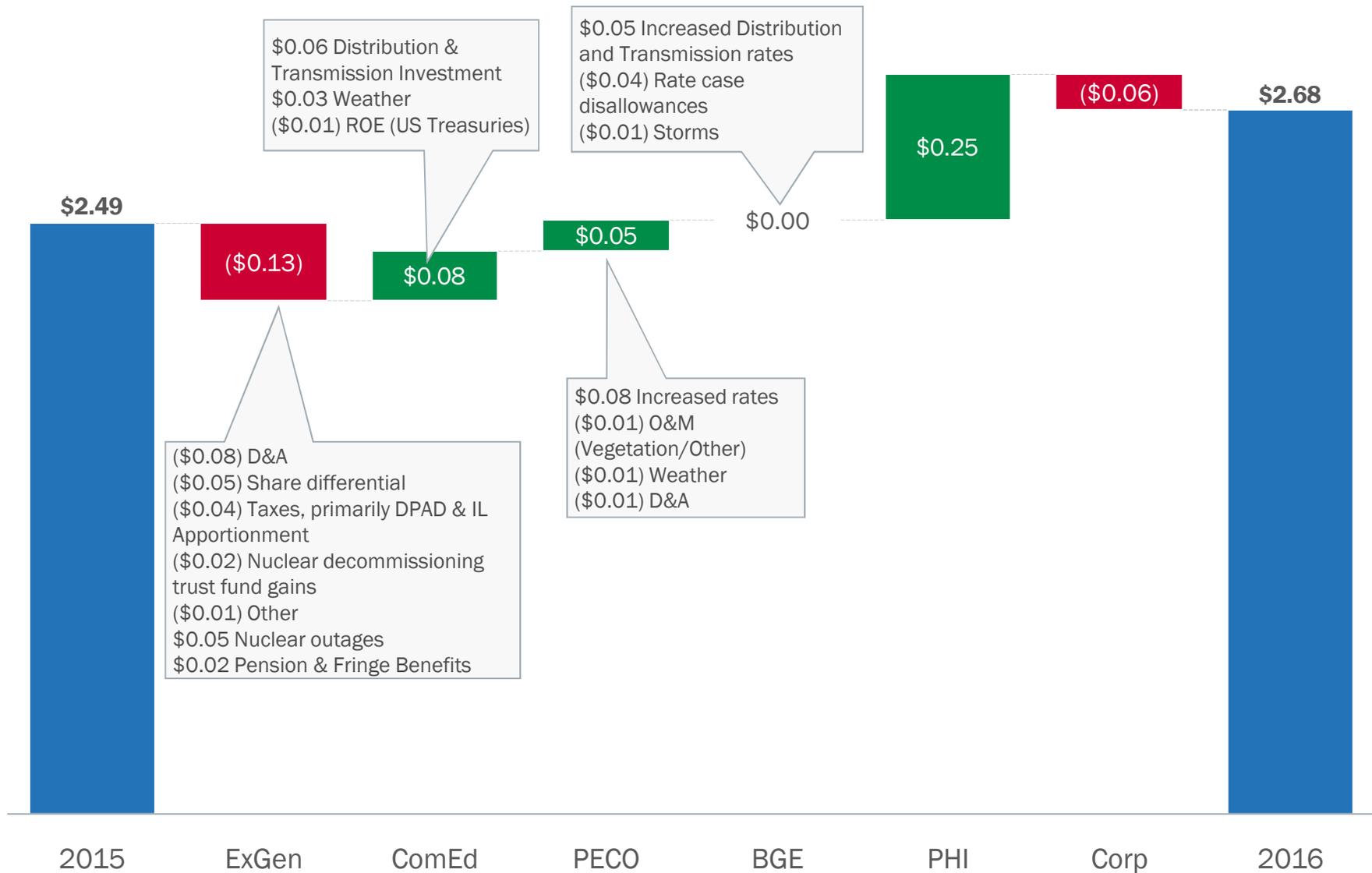
(7) ExGen adjusted O&M excludes direct cost of sales for certain Constellation business, P&L neutral decommissioning costs and the impact from O&M related to variable interest entities. Refer to slide 75 for a reconciliation of adjusted (non-GAAP) O&M to GAAP O&M.

(8) TOTI excludes gross receipts tax of \$100M

(9) Interest expense includes impact of reduced capitalized interest due to Texas CCGT plants going into service in May and June of 2017. Capitalized interest will be an additional ~\$25M lower in 2018 as well due to this.

# 2016A Earnings Waterfalls

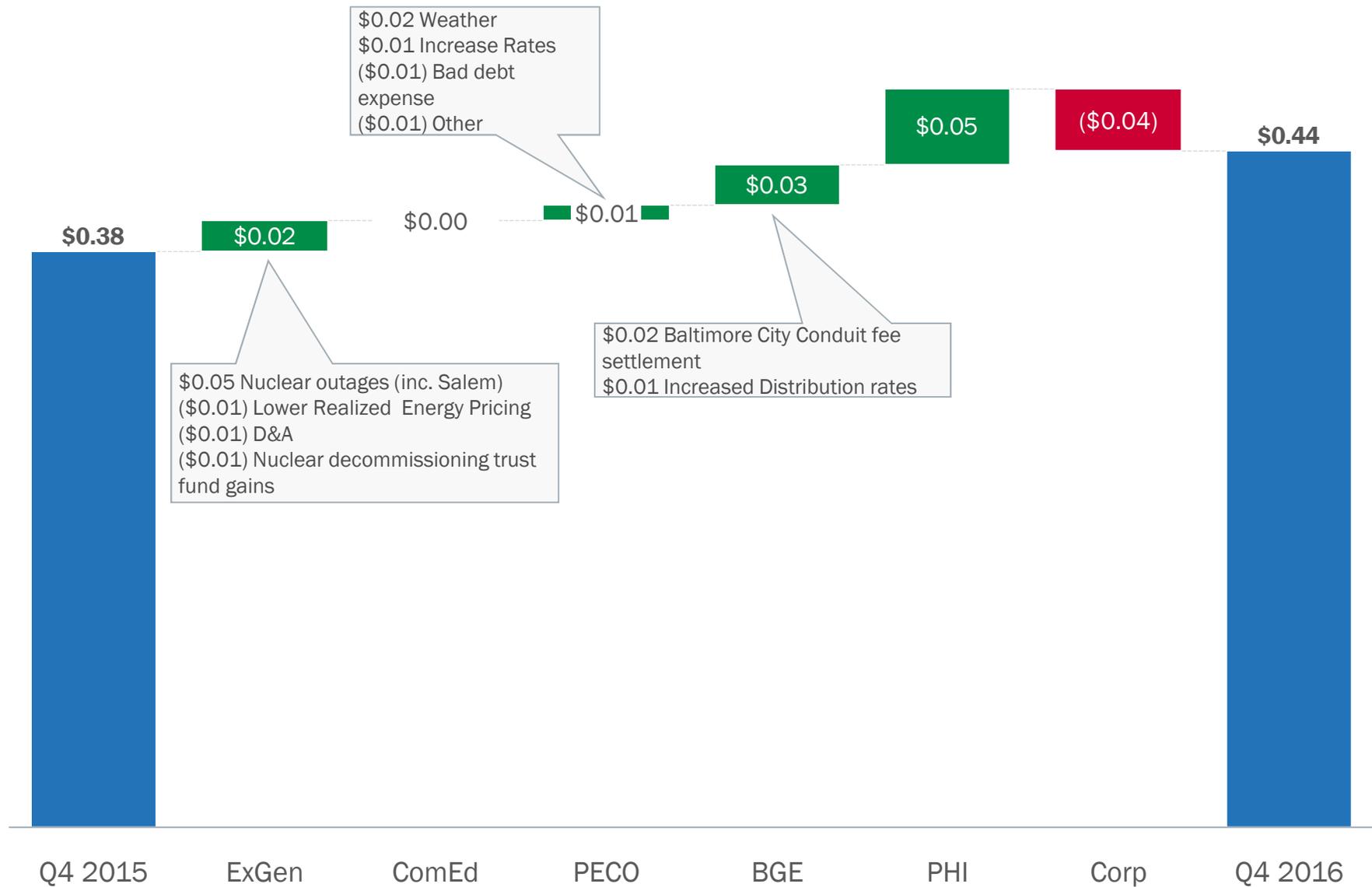
# FY Adjusted Operating Earnings Waterfall (1,2)



(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

(2) Amounts may not add due to rounding

# Q4 Adjusted Operating Earnings Waterfall (1,2)

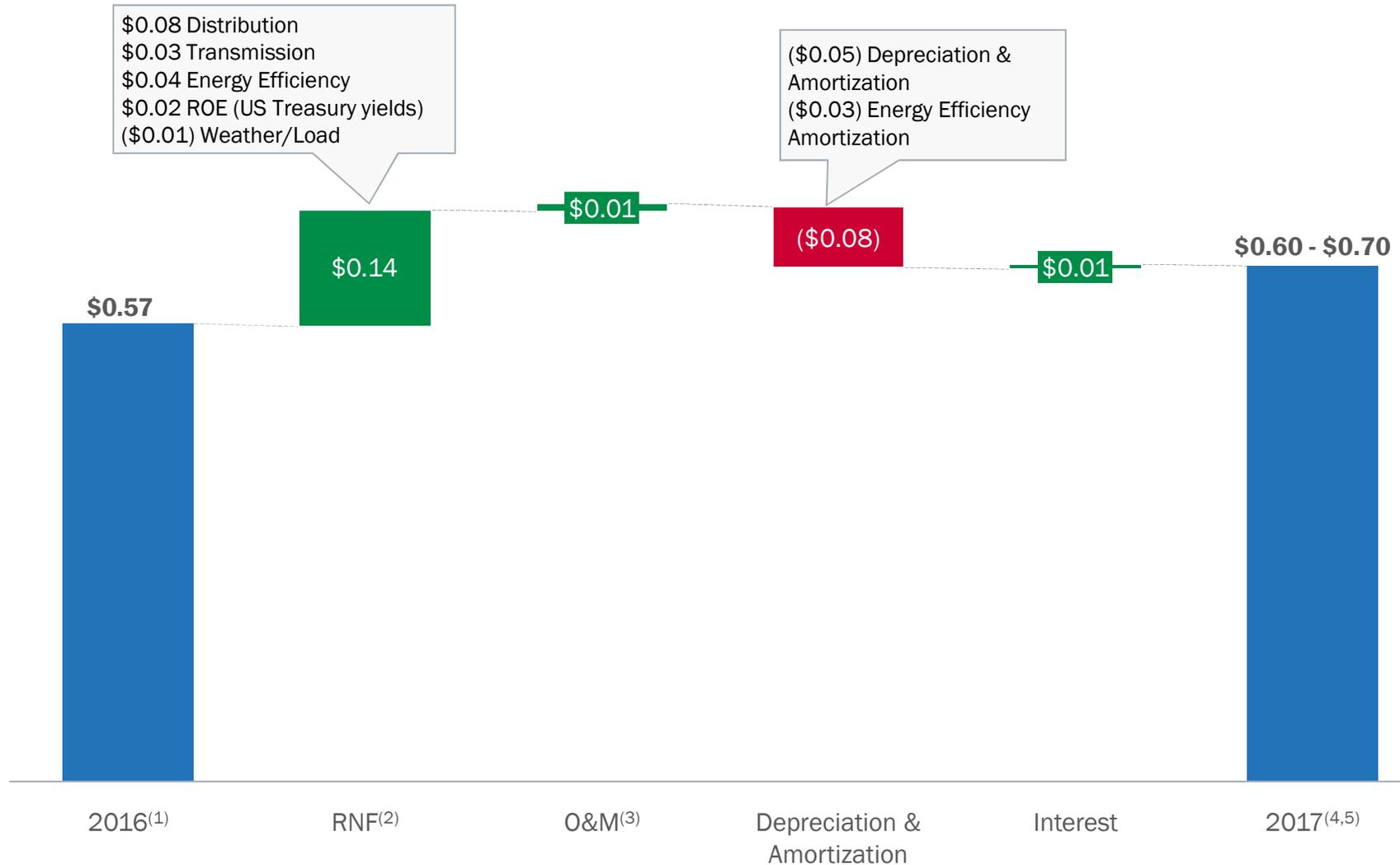


(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS  
 (2) Amounts may not add due to rounding



# 2017E Earnings Waterfalls

# ComEd Adjusted Operating EPS Bridge 2016 to 2017



Note: Drivers add up to mid-point of 2017 adjusted operating EPS range

(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

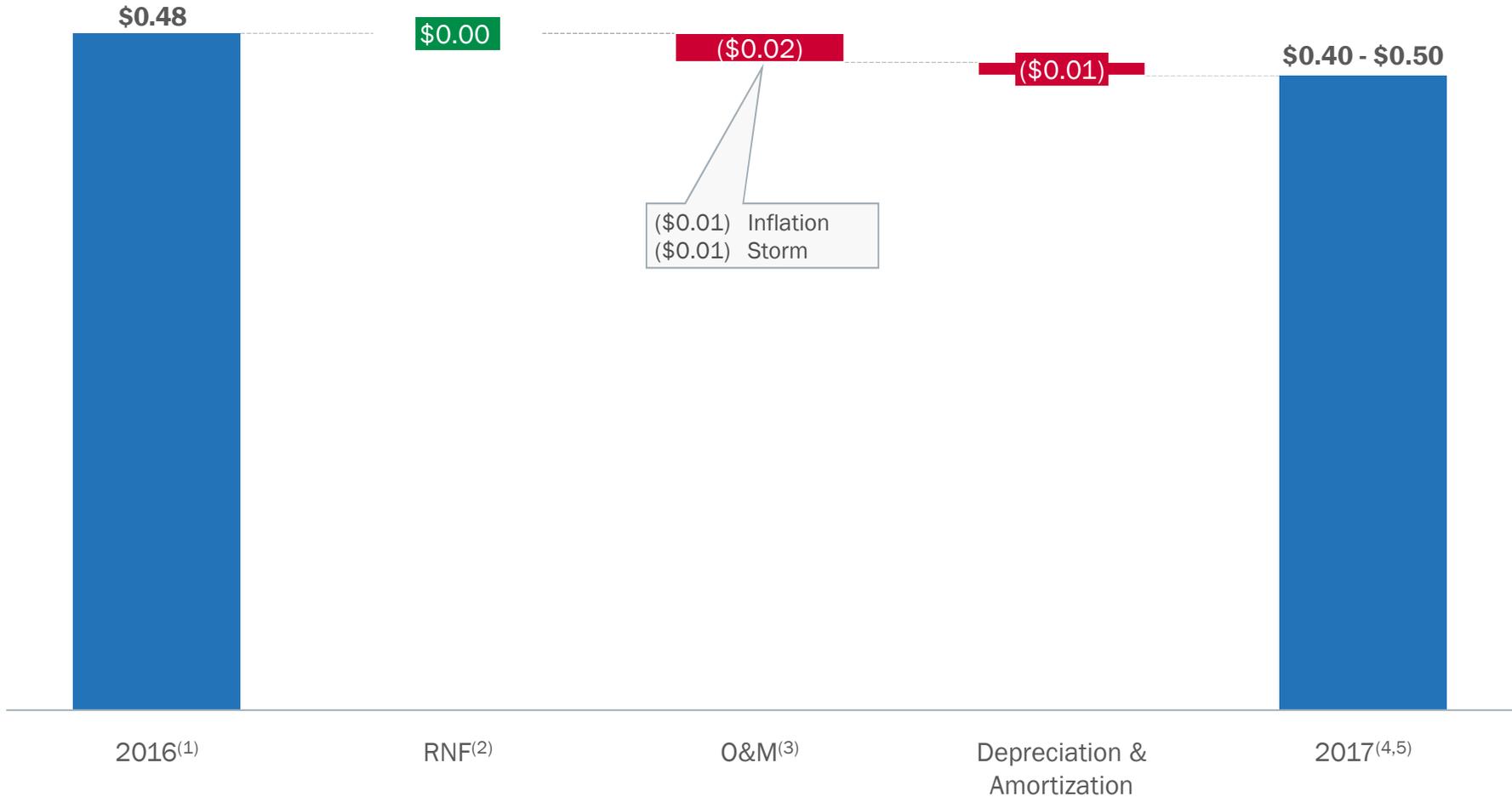
(2) Revenue net fuel (RNF) is defined as operating revenues less purchased power and fuel expense

(3) O&M excludes regulatory items that are P&L neutral

(4) Shares Outstanding (diluted) are 927M in 2016 and 949M in 2017. Refer to slide 72 for a reconciliation of adjusted (non-GAAP) operating EPS guidance to GAAP EPS

(5) Guidance assumes an effective tax rate for 2017 of 39.9%.

# PECO Adjusted Operating EPS Bridge 2016 to 2017



Note: Drivers add up to mid-point of 2017 adjusted operating EPS range

(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

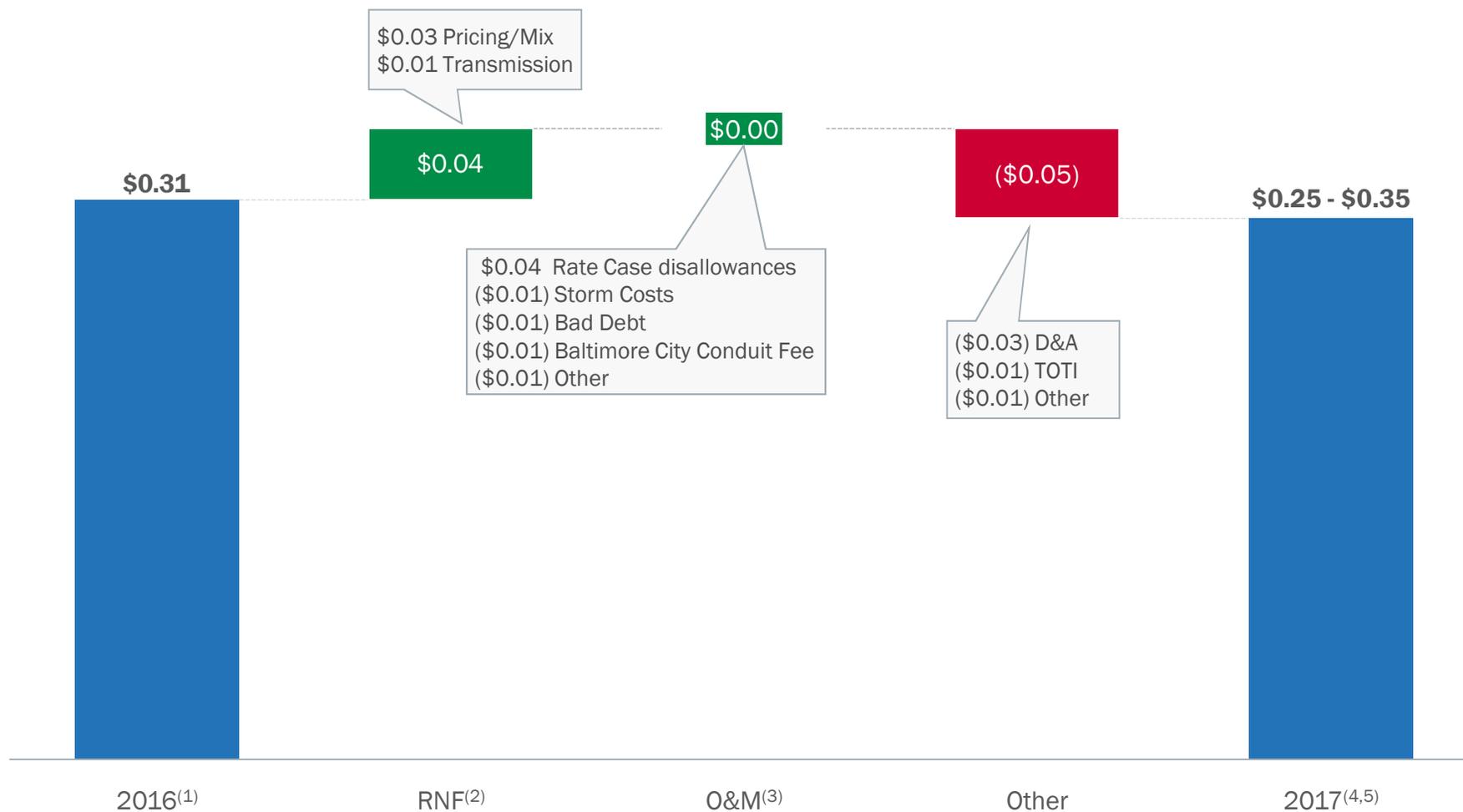
(2) Revenue net fuel (RNF) is defined as operating revenues less purchased power and fuel expense

(3) O&M excludes regulatory items that are P&L neutral

(4) Shares Outstanding (diluted) are 927M in 2016 and 949M in 2017. Refer to slide 72 for a reconciliation of adjusted (non-GAAP) operating EPS guidance to GAAP EPS

(5) Guidance assumes an effective tax rate for 2017 of 21.8%

# BGE Adjusted Operating EPS Bridge 2016 to 2017



Note: Drivers add up to mid-point of 2017 adjusted operating EPS range

(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

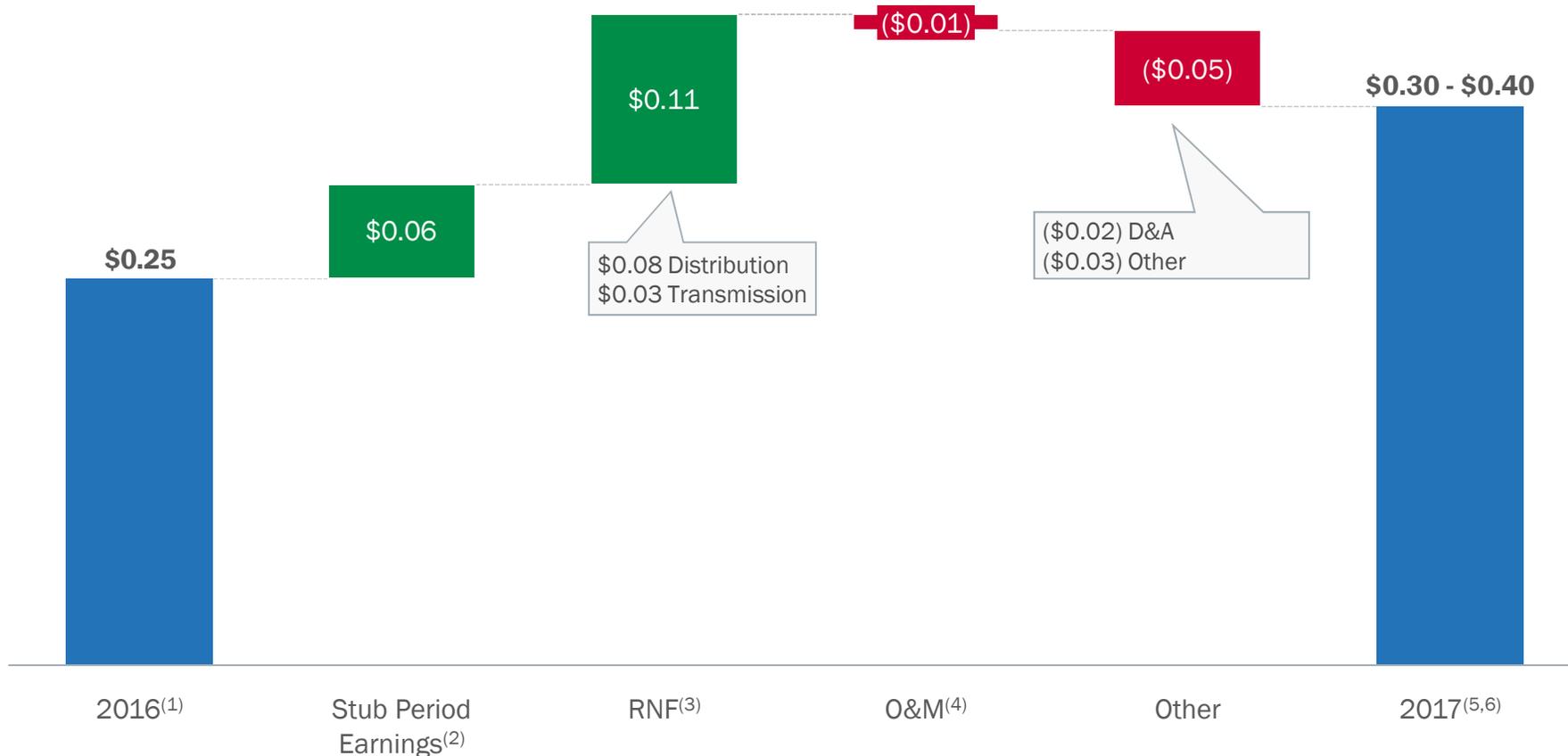
(2) Revenue net fuel (RNF) is defined as operating revenues less purchased power and fuel expense

(3) O&M excludes regulatory items that are P&L neutral

(4) Shares Outstanding (diluted) are 927M in 2016 and 949M in 2017. Refer to slide 72 for a reconciliation of adjusted (non-GAAP) operating EPS guidance to GAAP EPS

(5) Guidance assumes an effective tax rate for 2017 of 39.5%

# PHI Adjusted Operating EPS Bridge 2016 to 2017



Note: Drivers add up to mid-point of 2017 adjusted operating EPS range

(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

(2) Stub period earnings reflect earnings prior to merger close date of March 23, 2016

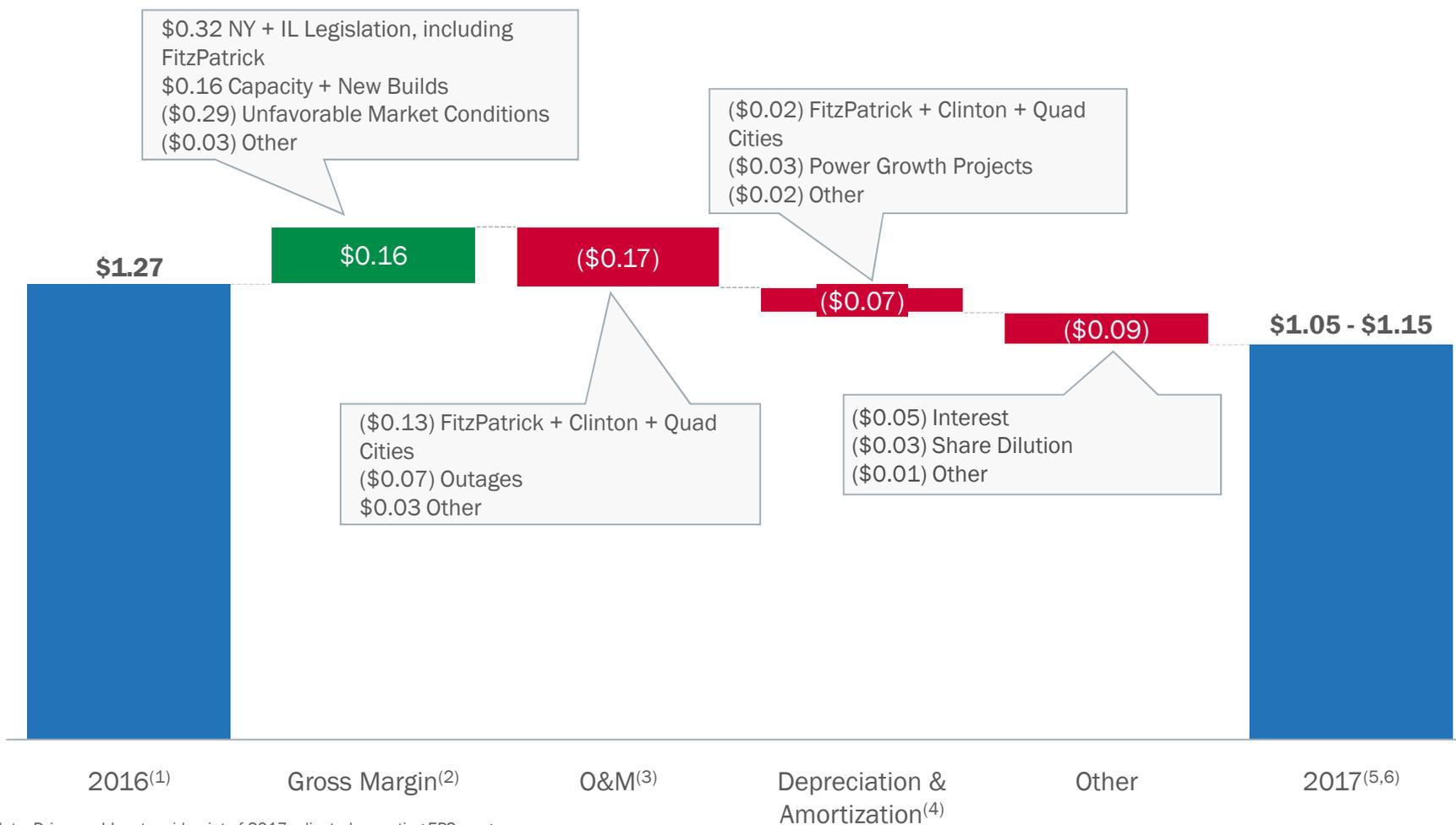
(3) Revenue net fuel (RNF) is defined as operating revenues less purchased power and fuel expense

(4) O&M excludes regulatory items that are P&L neutral

(5) Shares Outstanding (diluted) are 927M in 2016 and 949M in 2017. Refer to slide 72 for a reconciliation of adjusted (non-GAAP) operating EPS guidance to GAAP EPS.

(6) Guidance assumes an effective tax rate for 2017 of 35.6%

# ExGen Adjusted Operating EPS Bridge 2016 to 2017



Note: Drivers add up to mid-point of 2017 adjusted operating EPS range.

- (1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS
- (2) Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation and Power businesses. See Slide 50 for a Non-GAAP to GAAP reconciliation of Total Gross Margin.
- (3) O&M excludes items that are P&L neutral (including decommissioning costs and variable interest entities) and direct cost of sales for certain Constellation businesses
- (4) Depreciation & Amortization excludes cost of sales for certain Constellation businesses, which are included in gross margin
- (5) Shares Outstanding (diluted) are 927M in 2016 and 949M in 2017. Refer to slide 72 for a reconciliation of adjusted (non-GAAP) operating EPS guidance to GAAP EPS.
- (6) Guidance assumes an effective tax rate for 2017 of 32%



# Exelon Utilities Rate Case Filing Summaries

## ComEd April 2016 Distribution Formula Rate

The 2016 distribution formula rate filing established the net revenue requirement used to set the rates that took effect in January 2017 after the Illinois Commerce Commission's (ICC's) review. There are two components to the annual distribution formula rate filing:

- **Filing Year:** Based on 2015 costs and 2016 projected plant additions.
- **Annual Reconciliation:** For 2015, this amount reconciles the revenue requirement reflected in rates in effect during 2015 to the actual costs for that year. The annual reconciliation impacts cash flow in 2017 but the earnings impact has been recorded in 2015 as a regulatory asset.

<b>Docket #</b>	<b>16-0259</b>
<b>Filing Year</b>	<b>2015 Calendar Year Actual Costs and 2016 Projected Net Plant Additions</b> are used to set the rates for calendar year 2017. Rates currently in effect (docket 15-0287) for calendar year 2016 were based on 2014 actual costs and 2015 projected net plant additions.
<b>Reconciliation Year</b>	<b>Reconciles Revenue Requirement reflected in rates during 2015 to 2015 Actual Costs Incurred.</b> Revenue requirement for 2015 is based on docket 14-0312 (2013 actual costs and 2014 projected net plant additions) approved in December 2014.
<b>Common Equity Ratio</b>	~ <b>46%</b> for both the filing and reconciliation year
<b>ROE</b>	<b>8.64%</b> for the filing year (2015 30-yr Treasury Yield of 2.84% + 580 basis point risk premium) and <b>8.59%</b> for the reconciliation year (2015 30-yr Treasury Yield of 2.79% + 580 basis point risk premium – 5 basis points performance metrics penalty). For 2016 and 2017, 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
<b>Requested Rate of Return</b>	~ <b>7%</b> for both the filing and reconciliation years
<b>Rate Base<sup>(4)</sup></b>	<b>\$8,831 million</b> – Filing year (represents projected year-end rate base using 2015 actual plus 2016 projected capital additions). 2016 and 2017 earnings will reflect 2016 and 2017 year-end rate base respectively. \$7,782 million - Reconciliation year (represents year-end rate base for 2015)
<b>Revenue Requirement Increase<sup>(1)</sup></b>	<b>\$127M increase</b> (\$7M decrease due to the 2015 reconciliation and collar adjustment offset by a \$134M increase related to the filing year). The 2015 reconciliation impact on net income was recorded in 2015 as a regulatory asset.
<b>Timeline</b>	<ul style="list-style-type: none"> <li>• 04/13/16 Filing Date</li> <li>• 240 Day Proceeding</li> </ul>

**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) Amounts represent the approved amounts within the Illinois Commerce Commission's final order, received on December 6, 2016. The ICC ordered rehearing on one narrow topic that ComEd expects to result in a further \$17.5M reduction to the revenue requirement.

## Pepco MD Electric Distribution Rate Case – Final Order

<b>Docket #</b>	9418
<b>Test Year</b>	2015 Calendar Year
<b>Test Period</b>	12 months actual
<b>Authorized Common Equity Ratio</b>	49.55%
<b>Authorized Rate of Return</b>	ROE: 9.55%; ROR: 7.49%
<b>Authorized Rate Base</b>	Rate Base: \$1.64B
<b>Authorized Revenue Requirement Increase</b>	Revenue Increase: \$52.5M  Revenue increase includes approximately \$32.1M of new depreciation and amortization expense.
<b>Residential Total Bill % Increase</b>	4.76%
<b>Notes</b>	<ul style="list-style-type: none"> <li>• Order received on November 15</li> <li>• Advanced Metering (AMI) system deemed cost-beneficial and recovery to begin</li> <li>• Post-test period AMI costs deferred to new regulatory asset</li> <li>• Legacy meter recovery approved over 10 years with no return</li> <li>• Post-test period reliability capital placed in service through March 2016 approved with some disallowance</li> <li>• Extension of the Grid Resiliency Program in 2017-2018 was not approved</li> </ul>

## DPL DE (Electric) Distribution Rate Case

<b>Docket #</b>	16-0649
<b>Test Year</b>	2015 Calendar Year
<b>Test Period</b>	12 months actual
<b>Requested Common Equity Ratio</b>	49.44%
<b>Requested Rate of Return</b>	ROE: 10.60%; ROR: 7.19%
<b>Proposed Rate Base (Adjusted)</b>	\$839M
<b>Requested Revenue Requirement Increase (Updated on January 11, 2017)</b>	\$60.2M <sup>(1)(2)</sup>
<b>Residential Total Bill % Increase</b>	7.25%
<b>Notes</b>	<ul style="list-style-type: none"> <li>• 5/17/16 DPL DE filed application with the DPSC seeking increase in electric distribution base rates</li> </ul> <p>Intervenor Positions:</p> <ul style="list-style-type: none"> <li>• Staff \$9.5M revenue increase based on 9.20% ROE</li> <li>• Division of the Public Advocate (DPA) \$12.9M revenue increase based on 9.00% ROE</li> </ul> <p>Procedural Schedule:</p> <ul style="list-style-type: none"> <li>• Evidentiary Hearings: 3/7/17 – 3/9/17</li> <li>• Commission Order Expected: Q3 2017</li> </ul>

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of \$2.5 million on July 16, 2016, and implemented an incremental \$29.6M on December 17, 2016, subject to refund

(2) Revenue requirement includes changes in depreciation and amortization expense, which have no impact on pre-tax earnings

## DPL DE (Gas) Distribution Rate Case

<b>Docket #</b>	16-0650
<b>Test Year</b>	2015 Calendar Year
<b>Test Period</b>	12 months actual
<b>Requested Common Equity Ratio</b>	49.44%
<b>Requested Rate of Return</b>	ROE: 10.60%; ROR: 7.19%
<b>Proposed Rate Base (Adjusted)</b>	\$362M
<b>Requested Revenue Requirement Increase</b>	\$21.5M <sup>(1)(2)</sup>
<b>Residential Total Bill % Increase</b>	10.40%
<b>Notes</b>	<ul style="list-style-type: none"> <li>• 5/17/16 DPL DE filed application with the DPSC seeking increase in gas distribution base rates</li> </ul> <p>Intervenor Positions:</p> <ul style="list-style-type: none"> <li>• Staff revenue decrease of \$3.1M based on 9.20% ROE</li> <li>• Division of the Public Advocate (DPA) revenue decrease of \$2.1M based on 9.00% ROE</li> </ul> <p>Procedural Schedule:</p> <ul style="list-style-type: none"> <li>• Evidentiary Hearings: 4/5/17 – 4/7/17</li> <li>• Commission Order Expected: Q3 2017</li> </ul>

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of \$2.5 million on July 16, 2016, and implemented an incremental \$10.4M on December 17, 2016, subject to refund

(2) Revenue requirement includes changes in depreciation and amortization expense, which have no impact on pre-tax earnings

## Pepco DC Distribution Rate Case

<b>Formal Case No.</b>	1139
<b>Test Year</b>	April 1, 2015 – March 31, 2016
<b>Test Period</b>	12 months actual
<b>Requested Common Equity Ratio</b>	49.14%
<b>Requested Rate of Return</b>	ROE: 10.60%; ROR: 8.00%
<b>Proposed Rate Base (Adjusted)</b>	\$1.7B
<b>Requested Revenue Requirement Increase (Updated on February 1, 2017)</b>	\$76.8M <sup>(1)</sup>
<b>Residential Total Bill % Increase</b>	4.62% <sup>(2)</sup>
<b>Notes</b>	<ul style="list-style-type: none"> <li>• 6/30/16 Pepco DC filed application with the DCPSC seeking increase in electric distribution base rates</li> </ul> <p>Intervenor Positions:</p> <ul style="list-style-type: none"> <li>• Office of the People’s Council (OPC) revenue increase of \$20.1M based on 8.60% ROE</li> <li>• Apartment and Office Building Association (AOBA) revenue increase of \$62.2M based on 9.25% ROE</li> <li>• Healthcare Council of the National Capital Area (HCNCA) revenue increase of \$16.8M based on 8.75% ROE</li> <li>• District of Columbia Water and Sewer Authority (DC Water) revenue increase of \$52.7M based on 9.10% ROE</li> </ul> <p>Procedural Schedule:</p> <ul style="list-style-type: none"> <li>• Evidentiary Hearings: 3/15/17 – 3/21/17</li> <li>• Final Briefs: 4/24/17</li> <li>• Commission Order Expected: 7/25/17</li> </ul>

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

(2) As proposed by the Company, the full allocation of the CBRC to Residential and MMA customers, along with the proposal for a \$1M Incremental Offset for residential customers, will ensure that residential customers do not receive an increase on the distribution portion of their bill until approximately January 2019 (February 2019 for MMA customers). Upon expiration of the CBRC and Incremental Offset proposed by the Company, this rate increase would translate to a 4.62% total bill increase for a residential customer.

## DPL MD Distribution Rate Case

Case No. 9424	Company's Filed Position	Chief Public Utility Law Judge (CPULJ)
<b>Test Year</b>	April 1, 2015 – March 31, 2016	
<b>Test Period</b>	12 months actual	
<b>Requested Common Equity Ratio</b>	49.1%	49.1%
<b>Requested Rate of Return</b>	ROE: 10.60%; ROR: 7.24%	ROE: 9.48%; ROR: 6.69%
<b>Proposed Rate Base (Adjusted)</b>	\$727M	\$706M
<b>Requested Revenue Requirement Increase (Updated on October 18, 2016)</b>	\$57M	\$34.1M
<b>Residential Total Bill % Increase</b>	14.5%	6.53%
<b>Notes</b>	<ul style="list-style-type: none"> <li>7/20/16 DPL MD filed application with the MDPSC seeking increase in electric distribution base rates</li> </ul> <p>Intervenor Positions:</p> <ul style="list-style-type: none"> <li>Staff revenue increase of \$37.4M based on 9.48% ROE</li> <li>Office of the People's Council (OPC) revenue increase of \$22.9M based on 8.60% ROE</li> <li>Intervenors: Staff, OPC, Maryland Energy Group and Hanover Foods</li> </ul> <p>Procedural Schedule:</p> <ul style="list-style-type: none"> <li>CPULJ Proposed Order Received: 1/4/17</li> <li>Commission Order Expected: 2/17/17</li> </ul>	<ul style="list-style-type: none"> <li>1/4/17 the CPULJ issued a proposed order</li> <li>Advanced Metering ("AMI") system deemed cost-beneficial, and recovery to begin</li> <li>Legacy meter recovery approved over 10 years, with no return</li> <li>Post-test period reliability capital placed in service through September 2016 approved</li> <li>Extension of the Grid Resiliency Program in 2017-2018 was not approved</li> <li>The Company filed an appeal on January 18</li> </ul>

# **Appendix**

## **Reconciliation of Non-GAAP Measures**

## 4Q QTD GAAP EPS Reconciliation

<u>Three Months Ended December 31, 2015</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>PHI</u>	<u>Other</u>	<u>Exelon</u>
<b>2015 GAAP Earnings (Loss) Per Share</b>	<b>\$0.17</b>	<b>\$0.09</b>	<b>\$0.09</b>	<b>\$0.08</b>	<b>\$0.00</b>	<b>\$(0.09)</b>	<b>\$0.33</b>
Unrealized gains related to NDT fund investments	(0.05)	-	-	-	-	-	(0.05)
Merger and integration costs	-	-	-	-	-	0.01	0.01
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Long-Lived asset impairments	0.01	-	-	-	-	-	0.01
Reassessment of state deferred income taxes	0.01	-	-	-	-	0.03	0.05
Reduction in state income tax reserve	(0.01)	-	-	-	-	-	(0.01)
PHI merger related redeemable debt exchange	-	-	-	-	-	0.01	0.01
CENG non-controlling interest	0.02	-	-	-	-	-	0.02
<b>2015 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$0.15</b>	<b>\$0.09</b>	<b>\$0.09</b>	<b>\$0.08</b>	<b>\$0.00</b>	<b>\$(0.04)</b>	<b>\$0.38</b>

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

## 4Q QTD GAAP EPS Reconciliation (continued)

<b>Three Months Ended December 31, 2016</b>	<b>ExGen</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>	<b>PHI</b>	<b>Other</b>	<b>Exelon</b>
<b>2016 GAAP (Loss) Earnings Per Share</b>	<b>\$(0.04)</b>	<b>\$0.09</b>	<b>\$0.10</b>	<b>\$0.11</b>	<b>\$0.03</b>	<b>\$(0.06)</b>	<b>\$0.22</b>
Mark-to-Market impact of economic hedging activities	(0.05)	-	-	-	-	-	(0.05)
Unrealized losses related to NDT fund investments	0.01	-	-	-	-	-	0.01
Amortization of commodity contract intangibles	0.03	-	-	-	-	-	0.03
Merger and integration costs	0.02	-	-	-	-	-	0.02
Reassessment of state deferred income taxes	0.02	-	-	-	-	-	0.01
Asset retirement obligation	(0.08)	-	-	-	-	-	(0.08)
Merger commitments	0.04	-	-	-	0.01	(0.01)	0.04
Plant retirements and divestitures	0.10	-	-	-	-	-	0.10
Cost management program	0.01	-	-	-	-	-	0.01
Curtailment of Generation growth and development activities	0.06	-	-	-	-	-	0.06
CENG non-controlling interest	0.07	-	-	-	-	-	0.07
<b>2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$0.18</b>	<b>\$0.09</b>	<b>\$0.10</b>	<b>\$0.11</b>	<b>\$0.05</b>	<b>\$(0.08)</b>	<b>\$0.44</b>

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

## 4Q YTD GAAP EPS Reconciliation

<u>Twelve Months Ended December 31, 2015</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>PHI</u>	<u>Other</u>	<u>Exelon</u>
<b>2015 GAAP Earnings (Loss) Per Share</b>	<b>\$1.54</b>	<b>\$0.48</b>	<b>\$0.42</b>	<b>\$0.31</b>	<b>\$0.00</b>	<b>\$(0.20)</b>	<b>\$2.54</b>
Mark-to-Market impact of economic hedging activities	(0.18)	-	-	-	-	-	(0.18)
Unrealized losses related to NDT fund investments	0.13	-	-	-	-	-	0.13
Merger and integration costs	0.02	0.01	-	-	-	0.03	0.07
Mark-to-market impact of PHI merger related interest rate swap	-	-	-	-	-	0.02	0.02
Long-lived asset impairments	0.01	-	-	-	-	0.02	0.02
Asset retirement obligation	(0.01)	-	-	-	-	-	(0.01)
Tax settlements	(0.06)	-	-	-	-	-	(0.06)
Midwest generation bankruptcy recoveries	(0.01)	-	-	-	-	-	(0.01)
PHI merger related redeemable debt exchange	-	-	-	-	-	0.01	0.01
Reassessment of state deferred income taxes	0.01	-	-	-	-	0.03	0.05
Reduction in state income tax reserve	(0.01)	-	-	-	-	-	(0.01)
CENG non-controlling interest	(0.04)	-	-	-	-	-	(0.04)
<b>2015 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$1.40</b>	<b>\$0.48</b>	<b>\$0.43</b>	<b>\$0.31</b>	<b>\$0.00</b>	<b>\$(0.13)</b>	<b>\$2.49</b>

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

## 4Q YTD GAAP EPS Reconciliation (continued)

<u>Twelve Months Ended December 31, 2016</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>PHI</u>	<u>Other</u>	<u>Exelon</u>
<b>2016 GAAP Earnings (Loss) Per Share</b>	<b>\$0.54</b>	<b>\$0.41</b>	<b>\$0.47</b>	<b>\$0.31</b>	<b>(\$0.07)</b>	<b>(\$0.44)</b>	<b>\$1.22</b>
Mark-to-Market impact of economic hedging activities	0.03	-	-	-	-	-	0.03
Unrealized gains related to NDT fund investments	(0.13)	-	-	-	-	-	(0.13)
Amortization of commodity contract intangibles	0.04	-	-	-	-	-	0.04
Merger and integration costs	0.04	-	-	-	0.05	0.04	0.12
Long-lived asset impairments	0.11	-	-	-	-	-	0.11
Asset retirement obligation	(0.08)	-	-	-	-	-	(0.08)
Reassessment of state deferred income taxes	0.02	-	-	-	-	(0.01)	0.01
Merger commitments	0.05	-	-	-	0.27	0.16	0.47
Plant retirements and divestitures	0.47	-	-	-	-	-	0.47
Cost management program	0.03	-	-	-	-	-	0.04
Like-kind exchange tax position	-	0.16	-	-	-	0.05	0.21
Curtailment of Generation growth and development activities	0.06	-	-	-	-	-	0.06
CENG non-controlling interest	0.11	-	-	-	-	-	0.11
<b>2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$1.27</b>	<b>\$0.57</b>	<b>\$0.48</b>	<b>\$0.31</b>	<b>\$0.25</b>	<b>(\$0.20)</b>	<b>\$2.68</b>

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

## GAAP to Operating Adjustments

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- **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 and losses 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 date of acquisition of Integrys in 2014 and ConEdison Solutions in 2016
  - Certain costs incurred associated with the PHI acquisition and pending FitzPatrick acquisition
  - Costs incurred related to a cost management program
  - Generation's non-controlling interest related to CENG exclusion items
  - Other unusual items

## GAAP to Non-GAAP Reconciliations

YE 2017 Exelon FFO Calculation (\$M) <sup>(1)</sup>		YE 2017 Exelon Adjusted Debt Calculation (\$M) <sup>(1)</sup>	
GAAP Operating Income	\$4,400	Long-Term Debt (including current maturities)	\$32,700
Depreciation & Amortization	\$2,875	Short-Term Debt	\$1,875
EBITDA	\$7,275	+ PPA Imputed Debt <sup>(5)</sup>	\$350
+/- Non-operating activities and nonrecurring items <sup>(3)</sup>	\$375	+ Operating Lease Imputed Debt <sup>(6)</sup>	\$850
- Interest Expense	(\$1,425)	+ Pension/OPEB Imputed Debt <sup>(7)</sup>	\$3,450
+ Current Income Tax (Expense)/Benefit	(\$125)	- Off-Credit Treatment of Debt <sup>(8)</sup>	(\$2,225)
+ Nuclear Fuel Amortization	\$1,050	- Surplus Cash Adjustment <sup>(9)</sup>	(\$550)
+/- Other S&P FFO Adjustments <sup>(4)</sup>	\$425	+/- Other S&P FFO Adjustments <sup>(4)</sup>	\$300
<b>= FFO (a)</b>	<b>\$7,575</b>	<b>= Adjusted Debt (b)</b>	<b>\$36,750</b>

YE 2017 Exelon FFO/Debt <sup>(2)</sup>		
FFO (a)	=	21%
Adjusted Debt (b)		

- (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. Refer to slide 72 for a list of operating adjustments to GAAP.
- (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 and mandatory convertible equity units
- (9) Applies 75% of excess cash against balance of LTD

## GAAP to Non-GAAP Reconciliations

YE 2017 ExGen Net Debt Calculation (\$M) <sup>(1)</sup>	
Long-Term Debt (including current maturities)	\$9,525
Short-Term Debt	\$825
- Surplus Cash Adjustment	(\$375)
<b>= Net Debt (a)</b>	<b>\$9,975</b>

YE 2017 ExGen Operating EBITDA Calculation (\$M) <sup>(1)</sup>	
GAAP Operating Income	\$1,225
Depreciation & Amortization	<u>\$1,200</u>
EBITDA	\$2,425
+/- Non-operating activities and nonrecurring items <sup>(2)</sup>	\$600
<b>= Operating EBITDA (b)</b>	<b>\$3,025</b>

YE 2017 Book Debt / EBITDA	
Net Debt (a)	= 3.3x
Operating EBITDA (b)	

YE 2017 ExGen Net Debt Calculation (\$M) <sup>(1)</sup>	
Long-Term Debt (including current maturities)	\$9,525
Short-Term Debt	\$825
- Surplus Cash Adjustment	(\$375)
- Nonrecourse Debt	(\$2,550)
<b>= Net Debt (a)</b>	<b>\$7,425</b>

YE 2017 ExGen Operating EBITDA Calculation (\$M) <sup>(1)</sup>	
GAAP Operating Income	\$1,225
Depreciation & Amortization	<u>\$1,200</u>
EBITDA	\$2,425
+/- Non-operating activities and nonrecurring items <sup>(2)</sup>	\$600
- EBITDA from projects financed by nonrecourse debt	(\$250)
<b>= Operating EBITDA (b)</b>	<b>\$2,775</b>

YE 2017 Recourse Debt / EBITDA	
Net Debt (a)	= 2.7x
Operating EBITDA (b)	

(1) All amounts rounded to the nearest \$25M

(2) Reflects impact operating adjustments on GAAP EBITDA. Refer to slide 72 for a list of operating adjustments to GAAP.

## GAAP to Non-GAAP Reconciliations

2016 Adjusted O&M Reconciliation (\$M) <sup>(1)</sup>	ExGen	ComEd	PECO	BGE	PHI <sup>(4)</sup>	Other	Exelon
<b>GAAP O&amp;M</b>	<b>\$5,650</b>	<b>\$1,525</b>	<b>\$800</b>	<b>\$725</b>	<b>\$1,525</b>	<b>\$100</b>	<b>\$10,325</b>
Regulatory O&M <sup>(2)</sup>	-	(225)	(75)	-	(100)	-	(400)
Long-lived asset impairment costs	(175)	-	-	-	-	-	(175)
Merger commitments and costs to achieve	-	-	-	-	(475)	(200)	(675)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses <sup>(3)</sup>	(475)	-	-	-	-	-	(475)
O&M for managed plants that are partially owned	(400)	-	-	-	-	-	(400)
Other	(25)	-	-	-	25	-	-
<b>Adjusted O&amp;M (Non-GAAP)</b>	<b>\$4,575</b>	<b>\$1,300</b>	<b>\$725</b>	<b>\$725</b>	<b>\$975</b>	<b>\$(100)</b>	<b>\$8,200</b>

2017 Adjusted O&M Reconciliation (\$M) <sup>(1)</sup>	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
<b>GAAP O&amp;M</b>	<b>\$5,775</b>	<b>\$1,300</b>	<b>\$850</b>	<b>\$750</b>	<b>\$1,100</b>	<b>\$(125)</b>	<b>\$9,650</b>
Regulatory O&M <sup>(2)</sup>	-	(25)	(75)	(\$25)	(100)	-	(225)
Decommissioning <sup>(2)</sup>	25	-	-	-	-	-	25
Long-lived asset impairment costs	-	-	-	-	-	-	-
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses <sup>(3)</sup>	(400)	-	-	-	-	-	(400)
O&M for managed plants that are partially owned	(425)	-	-	-	-	-	(425)
Other	(125)	-	-	-	(25)	-	(150)
<b>Adjusted O&amp;M (Non-GAAP)</b>	<b>\$4,850</b>	<b>\$1,275</b>	<b>\$775</b>	<b>\$725</b>	<b>\$975</b>	<b>\$(125)</b>	<b>\$8,475</b>

(1) All amounts rounded to the nearest \$25M

(2) Reflects earnings neutral O&M

(3) Reflects the direct cost of sales of certain Constellation and Power businesses of Generation, which are included in Total Gross Margin

(4) All amounts represent full year of spend at PHI

## GAAP to Non-GAAP Reconciliations

<b>2017 Adjusted Cash from Ops Calculation (\$M)<sup>(1)</sup></b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>	<b>PHI</b>	<b>ExGen</b>	<b>Other</b>	<b>Exelon</b>
Net cash flows provided by operating activities (GAAP)	\$950	\$725	\$700	\$1,125	\$3,475	(\$300)	\$6,650
Other cash from investing activities	-	-	\$25	-	(\$275)	-	(\$250)
Intercompany receivable adjustment	(\$350)	-	-	-	-	\$350	-
Counterparty collateral activity	-	-	-	-	\$425	-	\$425
<b>Adjusted Cash Flow from Operations</b>	<b>\$600</b>	<b>\$725</b>	<b>\$725</b>	<b>\$1,125</b>	<b>\$3,625</b>	<b>\$50</b>	<b>\$6,825</b>
<b>2017 Cash From Financing Calculation (\$M)<sup>(1)</sup></b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>	<b>PHI</b>	<b>ExGen</b>	<b>Other</b>	<b>Exelon</b>
Net cash flow provided by financing activities (GAAP)	\$1,200	\$175	\$200	\$125	(\$200)	\$425	\$1,950
Dividends paid on common stock	\$425	\$300	\$200	\$250	\$650	(\$575)	\$1,225
Intercompany receivable adjustment	\$350	-	-	-	-	(\$350)	-
<b>Financing Cash Flow</b>	<b>\$1,975</b>	<b>\$475</b>	<b>\$400</b>	<b>\$375</b>	<b>\$475</b>	<b>(\$500)</b>	<b>\$3,175</b>

<b>Exelon Total Cash Flow Reconciliation<sup>(1)</sup></b>	<b>2017</b>
<b>GAAP Beginning Cash Balance</b>	<b>\$650</b>
Adjustment for Cash Collateral Posted	\$375
Adjusted Beginning Cash Balance <sup>(3)</sup>	\$1,025
Net Change in Cash (GAAP) <sup>(2)</sup>	\$550
Adjusted Ending Cash Balance <sup>(3)</sup>	\$1,575
Adjustment for Cash Collateral Posted	(\$800)
<b>GAAP Ending Cash Balance</b>	<b>\$775</b>

(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) <sup>(1)</sup>		2017	2018	2019	2020
<b>GAAP O&amp;M</b>		<b>\$5,775</b>	<b>\$5,525</b>	<b>\$5,500</b>	<b>\$5,575</b>
Decommissioning <sup>(2)</sup>		25	50	50	50
Costs associated with early nuclear plant retirements		-	-	-	-
Long-lived asset impairment costs		-	-	-	-
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses <sup>(3)</sup>		(400)	(400)	(400)	(400)
O&M for managed plants that are partially owned		(425)	(425)	(425)	(450)
Other		(125)	-	-	-
<b>Adjusted O&amp;M (Non-GAAP)</b>		<b>\$4,850</b>	<b>\$4,725</b>	<b>\$4,725</b>	<b>\$4,775</b>

2016-2020 ExGen FCF Calculation – Analyst Day (\$M) <sup>(1)</sup>		2016-2020 ExGen FCF Calculation - Q4 2016 (\$M) <sup>(1)</sup>	
Cash from Operations (GAAP)	\$17,975	Cash from Operations (GAAP)	\$19,575
Other Cash from Investing Activities	(\$600)	Other Cash from Investing Activities	(\$950)
Baseline Capital Expenditures <sup>(4)</sup>	(\$4,625)	Baseline Capital Expenditures <sup>(4)</sup>	(\$5,025)
Nuclear Fuel Capital Expenditures	(\$4,525)	Nuclear Fuel Capital Expenditures	(\$4,850)
<b>Free Cash Flow before Growth CapEx and Dividend</b>	<b>\$8,225</b>	<b>Free Cash Flow before Growth CapEx and Dividend</b>	<b>\$8,750</b>

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

(1) All amounts rounded to the nearest \$25M

(2) Reflects earnings neutral O&M

(3) Reflects the direct cost of sales of certain businesses, which are included in Total Gross Margin, a non-GAAP measure

(4) Baseline capital expenditures refer to maintenance and required capital expenditures necessary for day-to-day plant operations and includes merger commitments

## GAAP to Non-GAAP Reconciliations

Operating ROE Reconciliation <sup>(1)</sup>	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP) <sup>(1)</sup>	(\$42)	(\$9)	\$42	\$1,102	\$1,103
Operating exclusions	\$99	\$89	\$127	\$146	\$461
Adjusted Operating Earnings <sup>(1)</sup>	\$57	\$80	\$170	\$1,258	\$1,564
Average Equity	\$1,017	\$1,282	\$2,270	\$11,951	\$16,523
<b>Operating ROE (Adjusted Operating Earnings/Average Equity)</b>	<b>5.6%</b>	<b>6.3%</b>	<b>7.5%</b>	<b>10.5%</b>	<b>9.5%</b>

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