

Earnings Conference Call 2nd Quarter 2018

August 2, 2018



Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2017 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, Commitments and Contingencies; (2) Exelon's Second Quarter 2018 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 17; and (2) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this press release. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

Non-GAAP Financial Measures

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

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

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

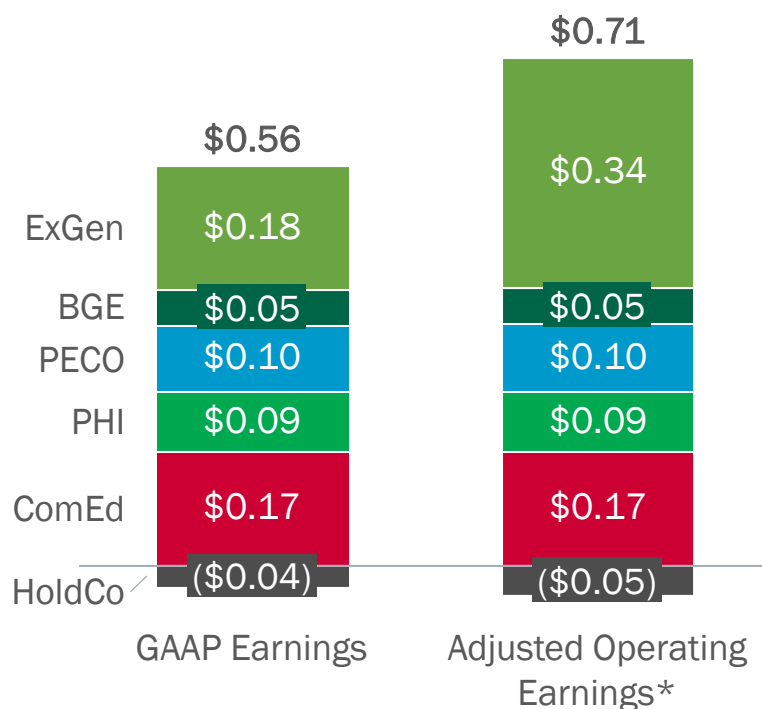
Non-GAAP Financial Measures Continued

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

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

Non-GAAP financial measures are identified by the phrase "non-GAAP" or an asterisk. Reconciliations of these non-GAAP measures to the most comparable GAAP measures are provided in the appendices and attachments to this presentation, except for the reconciliation for total gross margin, which appears on slide 42 of this presentation.

Q2 2018 EPS Results^(1,2)



- GAAP earnings were \$0.56/share in Q2 2018 vs. \$0.10/share in Q2 2017
- Adjusted operating earnings* were \$0.71/share in Q2 2018 vs. \$0.56/share in Q2 2017, exceeding our guidance range of \$0.55-\$0.65/share

(1) Amounts may not add due to rounding

(2) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018

Operating Highlights

Exelon Utilities Operational Metrics					
Operations	Metric	Q2 2018			
		BGE	ComEd	PECO	PHI
Electric Operations	OSHA Recordable Rate				
	2.5 Beta SAIFI (Outage Frequency) ⁽¹⁾				
	2.5 Beta CAIDI (Outage Duration)				
Customer Operations	Customer Satisfaction				
	Service Level % of Calls Answered in <30 sec				
	Abandon Rate				
Gas Operations	Percent of Calls Responded to in <1 Hour		No Gas Operations		

- Continued top tier reliability performance, with top decile performance in CAIDI and gas odor
- Customer performance metrics continue to be strong across all utilities

Q1	Q2
Q3	Q4

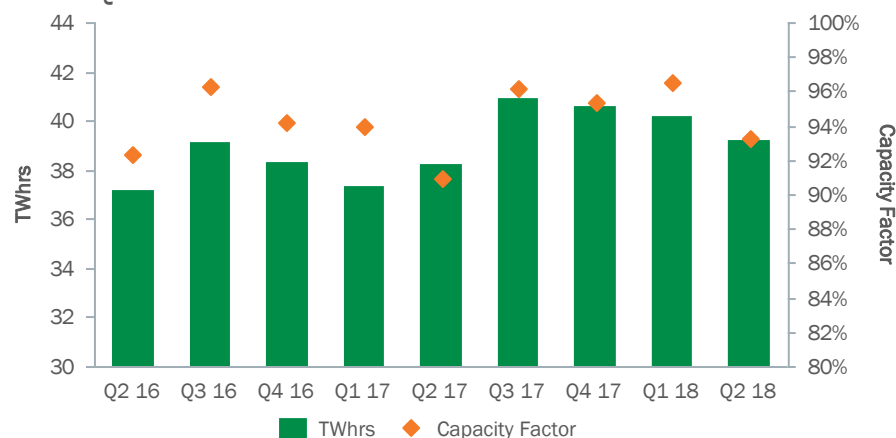
(1) 2.5 Beta SAIFI is YE projection

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

Exelon Generation Operational Performance

Exelon Nuclear Fleet⁽²⁾

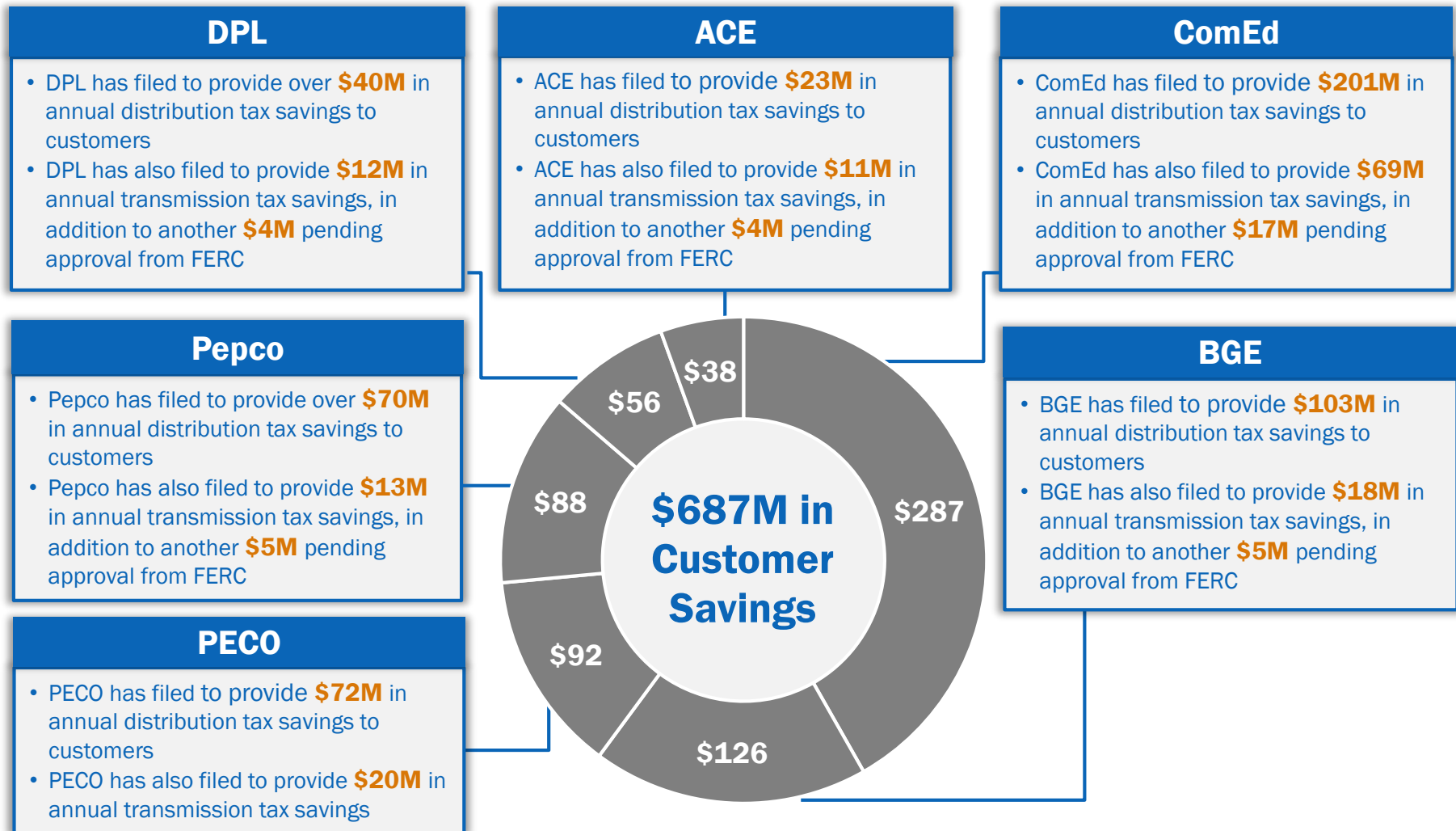
- Continued best in class performance across our Nuclear fleet:
 - Q2 2018 Nuclear Capacity Factor: 93.2%
 - 96 outage days in Q2 2018 compared to 137 in Q2 2017



Fossil and Renewable Fleet

- Strong performance across our Fossil and Renewable fleet:
 - Q2 2018 Renewables energy capture: 95.1%
 - Q2 2018 Power dispatch match: 97.8%

Tax Reform Producing Significant Customer Bill Savings



Utility customers across our jurisdictions will benefit from tax reform, saving over \$675M annually through planned and approved transmission and distribution bill adjustments

Constructive Legislation for Our Utilities

Delaware

- On June 14, Governor Carney signed Senate Bill 80, which enacted the Distribution System Investment Charge (DSIC) legislation
- The DSIC tracker establishes a system improvement charge that provides a mechanism to recover infrastructure investments, allowing for:
 - Gradual rate increases; and
 - Limiting frequency of rate cases
- DPL DE expects to make its first filing under the DSIC rules in Q4 2018, with the new charge appearing on customer bills by Q1 2019

Pennsylvania

- On June 28, Governor Wolf signed House Bill (HB) 1782
- HB 1782 authorizes the PA PUC to review and approve utility-proposed alternative rate mechanisms
 - Alternative methods include options such as decoupling mechanisms, formula rates, multi-year rate plans, and performance based rates
- HB 1782 will ensure that our utilities and state regulators have a full range of options to consider to meet PA's future infrastructure needs

Recent passage of legislation in DE and PA will support needed infrastructure investment that includes utility of the future initiatives to the benefit of our customers, while also allowing for timely recovery on those investments

ZEC & Energy Policy Updates

ZEC Updates

New Jersey:

- Governor Murphy signed the NJ ZEC bill into law on May 23rd
- Implementation of the program is scheduled to be completed around the end of Q1 2019

Illinois:

- Oral arguments for the 7th Circuit occurred on January 3, 2018, with requests for supplemental briefings
- Supplemental briefings were filed on January 26, 2018
- Court issued order on February 21, 2018, inviting the U.S. Government to provide its views
- U.S. Solicitor General responded in support of the case on May 29th
- Currently awaiting court decision

New York:

- Oral arguments for the 2nd Circuit occurred on March 12, 2018
- No outstanding items following oral arguments
- Currently awaiting court decision

FERC Capacity Order

- On June 29, 2018, FERC issued an order rejecting both capacity repricing and MOPREx, but finding that the existing tariff is not just and reasonable
- FERC established a paper hearing proceeding to develop a new, two-part approach:
 - **Alternative FRR:** enables states to establish asset specific FRR arrangements that would allow them to compensate those assets directly and remove the associated load from the RPM auction
 - **MOPR:** if FRR is not elected, an expanded MOPR would apply to all existing and new resources with out-of-market support, with no or few exceptions
- FERC has required comments within 60 days, with replies 30 days later
- FERC aims to reach a final decision by January 4, 2019

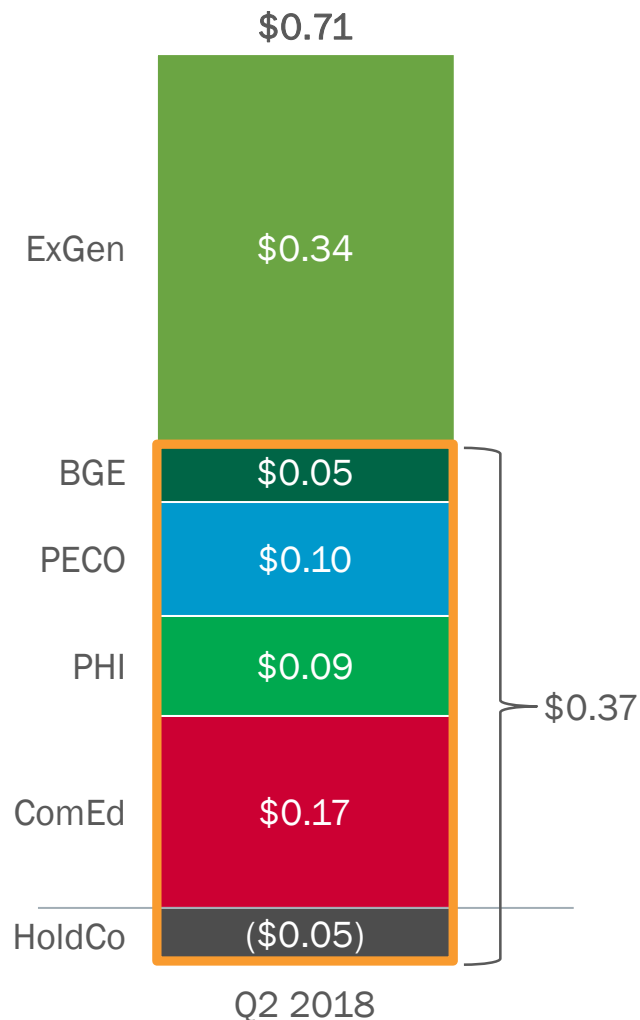
PJM Price Formation

- PJM fast start proceeding was initiated by FERC (Docket No. EL18-34) and has now been fully briefed
- FERC has committed to providing a decision in September 2018
 - If FERC approves in September, without changes, then PJM could implement the changes in winter 2018/2019
- After assessing FERC's fast start decision, PJM will determine path forward for full integer relaxation
 - PJM has not set a definitive timeline for stakeholder deliberations
- Deliberations regarding scarcity pricing and reserves reforms are ongoing in Q3 and Q4 for early 2019 action

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2nd Quarter Adjusted Operating Earnings* Drivers

Q2 2018 Adjusted Operating EPS* Results



Q2 2018 vs. Guidance of \$0.55 - \$0.65

Exelon Utilities

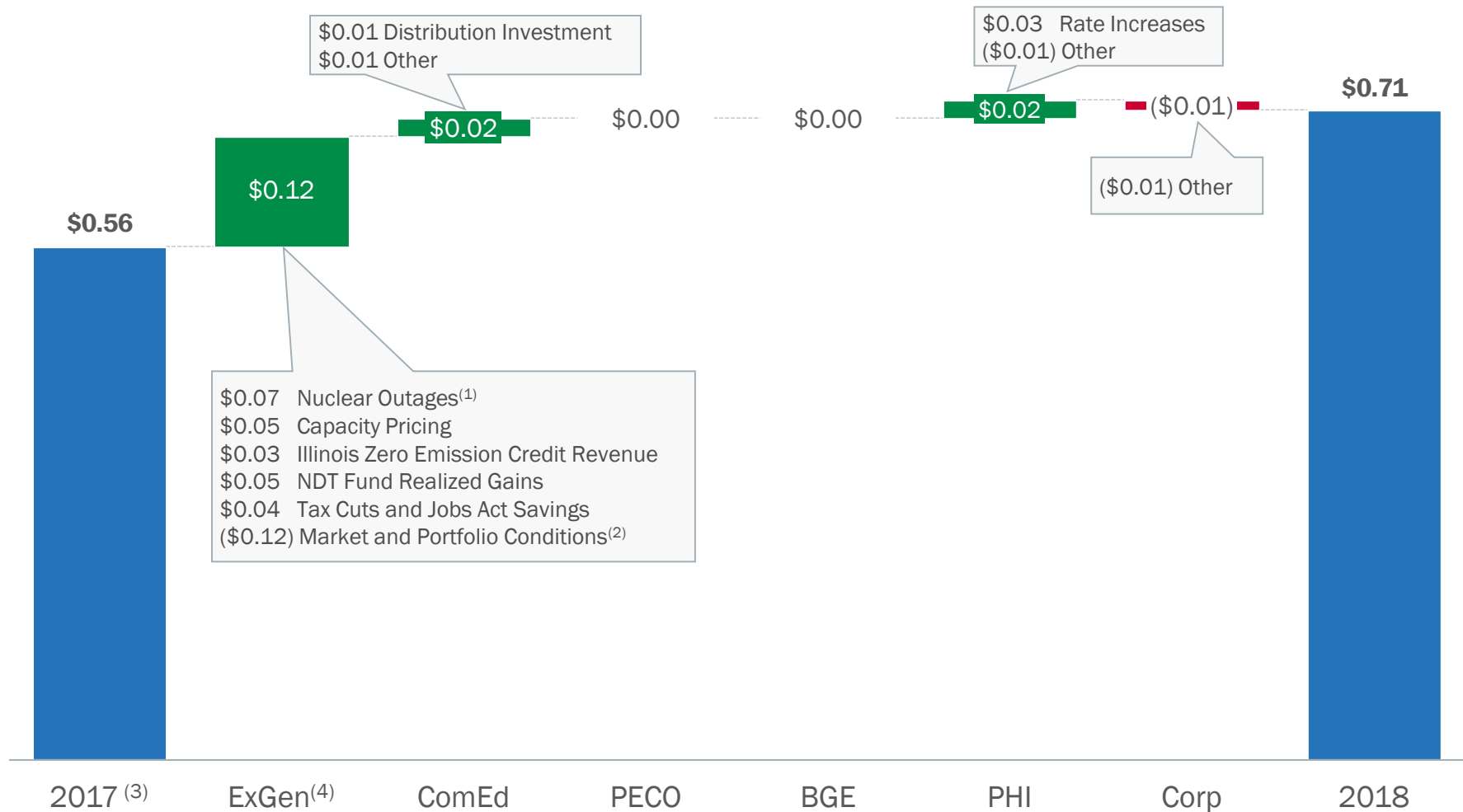
- ↑ Higher distribution and transmission revenue
- ↑ Favorable weather

Exelon Generation

- ↑ NDT realized gains⁽¹⁾
- ↑ Generation performance
- ↑ Favorable market conditions
- ↓ Higher transmission costs
- ↓ Other

Note: Amounts may not sum due to rounding
 (1) Gains related to unregulated sites

QTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

(1) Increase in volume due to a decrease in outage days in 2018; additionally operating and maintenance expense decreased due to a decrease in outage days in 2018, excluding Salem

(2) Primarily lower realized energy prices, partially offset by the favorable impact of Generation's natural gas portfolio

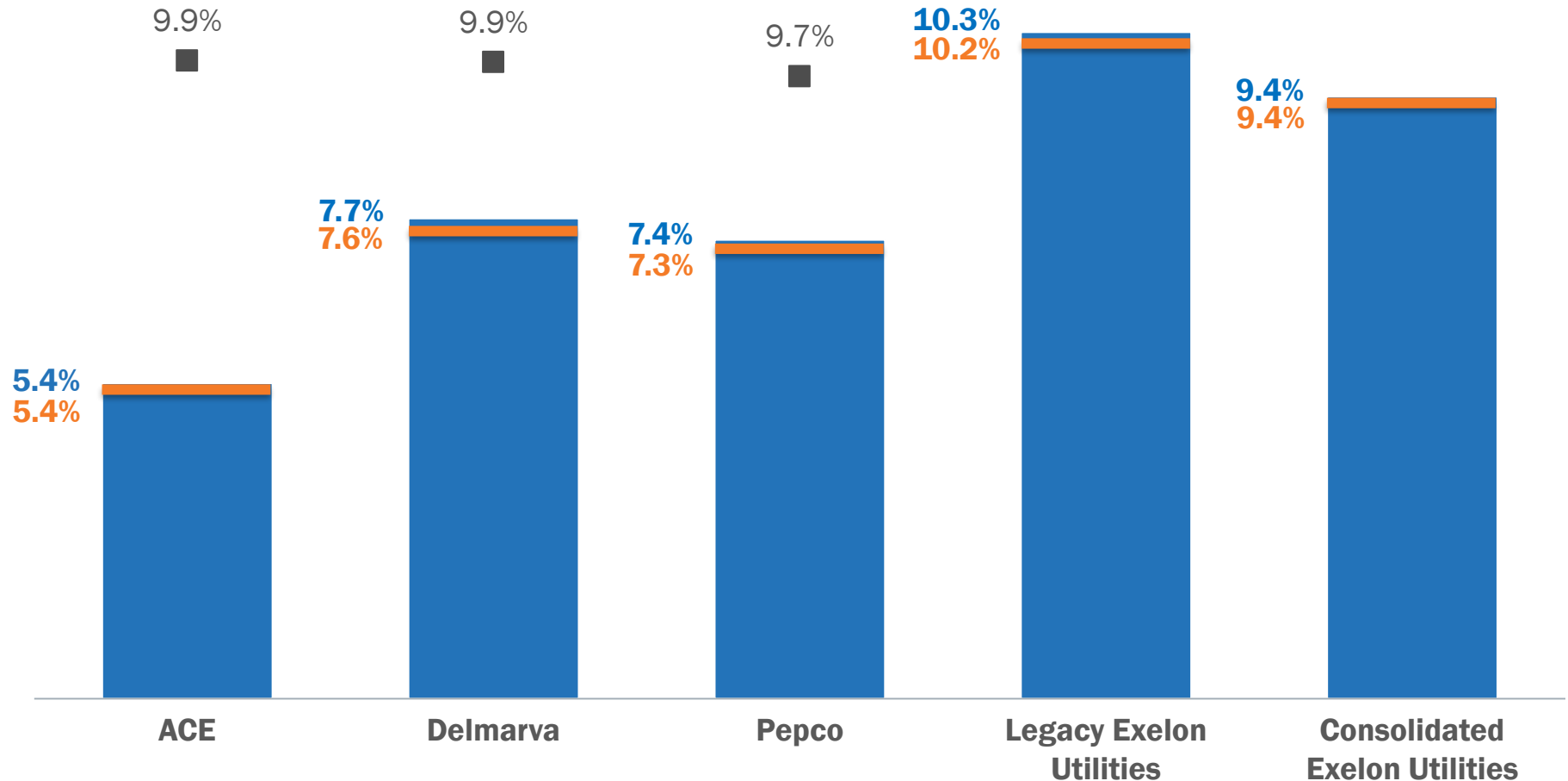
(3) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018

(4) Reflects CENG ownership at 100%

Trailing 12 Month Earned ROEs* vs Allowed ROE

Trailing Twelve Month Earned ROEs*

■ Allowed ROE — Q1 2018 TTM Earned ROE ■ Q2 2018 TTM Earned ROE



Note: Represents the 12-month periods ending 3/31/2018 and 6/30/2018, respectively. Earned ROEs* represent weighted average across all lines of business (Electric Distribution, Gas Distribution and Electric Transmission).

Exelon Utilities' Distribution Rate Case Updates

Rate Case Schedule and Key Terms

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Revenue Requirement	Requested ROE / Equity Ratio	Expected Order
ComEd	CF		IT	RT	EH	IB RB			FO				(\$22.9M) ⁽¹⁾	8.69% / 47.11%	Dec 2018
Delmarva Electric (DE)		RT	SA EH			FO							(\$6.9M) ^(1,3)	9.70% / 50.52%	Q3 2018
Delmarva Gas (DE)		IT		RT		EH	IB RB		FO				\$3.8M ^(1,4)	10.10% / 50.52%	Q4 2018
Pepco Electric (DC)	SA		IB			FO							(\$24.1M) ^(1,5)	9.525% / 50.44%	Q3 2018
Pepco Electric (MD)	SA	EH FO											(\$15.0M) ^(1,5)	9.50% / 50.44%	May 31, 2018
PECO Electric			IT	RT	EH	IB RB			FO				\$82M ⁽¹⁾	10.95% / 53.39%	Dec 2018
BGE⁽²⁾ Gas			CF			IT	RT	EH	IB	RB	FO		\$85M ⁽⁶⁾	10.50% / 53.40%	Jan 2019

CF	Rate case filed	RT	Rebuttal testimony	IB	Initial briefs	FO	Final commission order
IT	Intervenor direct testimony	EH	Evidentiary hearings	RB	Reply briefs	SA	Settlement agreement

Note: Based on current schedules of Illinois Commerce Commission, Maryland Public Service Commission, Delaware Public Service Commission, Public Service Commission of the District of Columbia, New Jersey Board of Public Utilities, and Pennsylvania Public Utility Commission and are subject to change

- (1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings
- (2) BGE briefing schedule will be determined during or at the end of the evidentiary hearing
- (3) As permitted by Delaware law, Delmarva Power implemented interim rate increases of \$2.5M on October 16, 2017, and implemented \$5.8M full allowable rates on March 17, 2018, subject to refund. Per non-unanimous Settlement Agreement filed on June 27, 2018. Includes tax benefits from Tax Cuts and Jobs Act.
- (4) As permitted by Delaware law, Delmarva Power implemented interim rate increases of \$2.5M on November 1, 2017, and implemented \$3.9M full allowable rates on March 17, 2018, subject to refund. Includes tax benefits from Tax Cuts and Jobs Act.
- (5) Per non-unanimous Settlement Agreement filed on April 17, 2018, for Pepco DC and April 20, 2018, for Pepco MD. Includes tax benefits from Tax Cuts and Jobs Act.
- (6) Reflects \$63M increase and \$22M STRIDE reset

Utility CapEx Update

PECO's Gas Main and Service Replacement Program

- **Forecasted project cost:**
 - \$2.3 billion of spend remaining
- **In service date:**
 - Multiple in service dates based on work plans with local townships
- **Project scope:**
 - Replace remaining 289 miles of gas services lines by end of 2022 and remaining 967 miles of main by end of 2035
 - Approximately 520 miles of mains and gas services lines have been replaced since 2010 at a cost of \$381 million
 - Reduces risk on distribution system by replacing leak and break susceptible materials



BGE's Investment in Trade Point Atlantic

- **Forecasted project cost:**
 - \$150 million investment in transmission & distribution over 5 years including the new 93 MW Fitzell substation
- **In service date:**
 - Fitzell substation: December 2020; electric and gas distribution investment: ongoing
- **Project scope:**
 - New substation as well as distribution infrastructure to support the new 3,100 acre Commercial & Industrial Trade Point Atlantic ("TPA") development
 - TPA is projected to generate 17,000 jobs, plus an additional 21,000 during construction; economic development is projected to be greater than \$3 billion when completed⁽¹⁾



(1) Economic data based on Sage Policy Group, Inc. report dated October 2016

Exelon Generation: Gross Margin Update

Gross Margin Category (\$M) ⁽¹⁾	June 30, 2018			Change from March 31, 2018		
	2018	2019	2020	2018	2019	2020
Open Gross Margin ^(2,5) (including South, West, Canada hedged gross margin)	\$4,700	\$4,050	\$3,800	\$100	\$100	-
Capacity and ZEC Revenues ^(2,5,6)	\$2,300	\$2,050	\$1,900	-	\$50	\$50
Mark-to-Market of Hedges ^(2,3)	\$400	\$400	\$300	\$100	\$(50)	\$50
Power New Business / To Go	\$150	\$600	\$800	\$(200)	\$(50)	\$(50)
Non-Power Margins Executed	\$350	\$150	\$100	\$50	-	-
Non-Power New Business / To Go	\$150	\$350	\$400	\$(50)	-	-
Total Gross Margin*^(4,5)	\$8,050	\$7,600	\$7,300	-	\$50	\$50

Recent Developments

- Strong second quarter executing \$200M of Power New Business in 2018 and \$50M in both 2019 and 2020
- Capacity and ZEC Revenues include the favorable impact of NJ ZEC revenues in 2019 and 2020
- Behind ratable hedging position reflects the upside we see in power prices
 - ~10-13% behind ratable in 2019 when considering cross commodity hedges

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

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

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

(4) Based on June 30, 2018, market conditions

(5) Reflects Oyster Creek and TMI retirements by October 2018 and September 2019, respectively. 2018, 2019 and 2020 are adjusted for retaining Handley Generating Station.

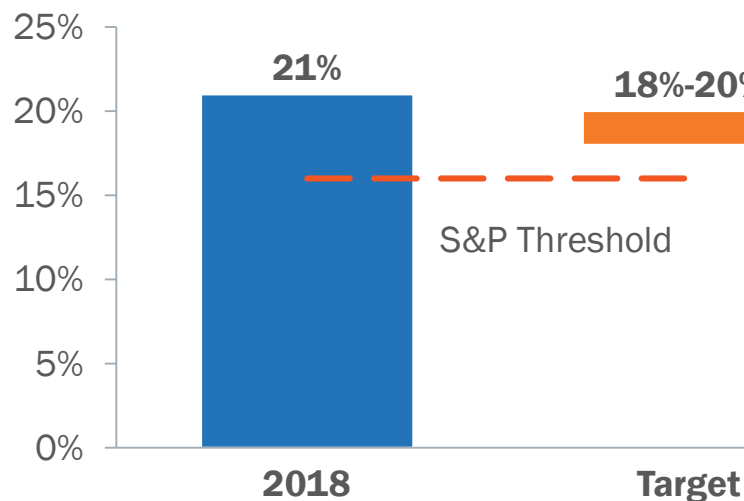
(6) 2018 includes \$150M of IL ZEC revenues associated with 2017 production. 2019 and 2020 include the favorable impact of NJ ZEC revenues.

Maintaining Strong Investment Grade Credit Ratings is a Top Financial Priority

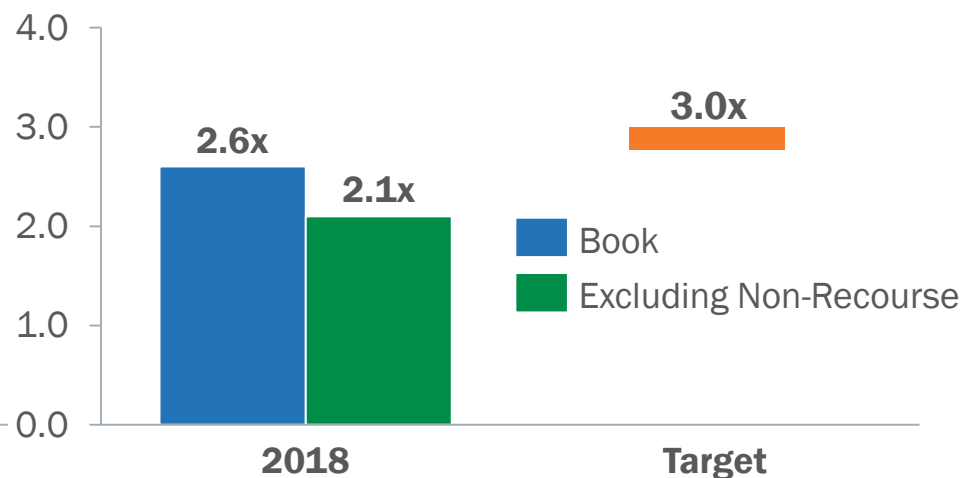
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Exelon S&P FFO/Debt %^{*(1,4)}



ExGen Debt/EBITDA Ratio^{*(5)}



Credit Ratings by Operating Company

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

(1) Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment

(2) Current senior unsecured ratings as of August 2, 2018, for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco

(3) Exelon, PECO, and BGE are on "Positive" outlook at Fitch, and ACE is on "Positive" outlook at Moody's; all other ratings have a "Stable" outlook

(4) Exelon Corp downgrade threshold (red dotted line) is based on the S&P Exelon Corp Summary Report; represents minimum level to maintain current Issuer Credit Rating at Exelon Corp

(5) Reflects net book debt (YE debt less cash on hand) / adjusted operating EBITDA*

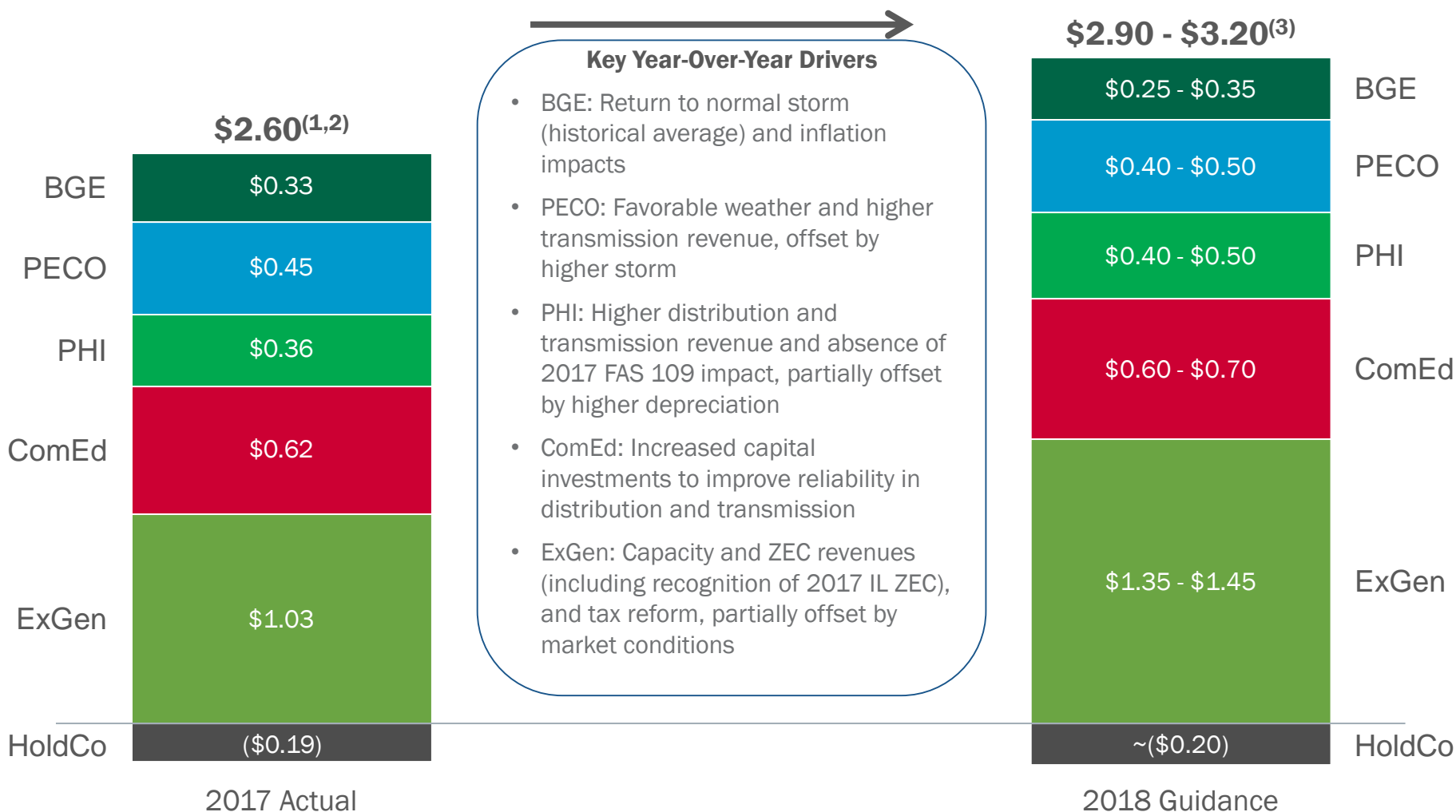
The Exelon Value Proposition

- **Regulated Utility Growth** with utility EPS rising 6-8% annually from 2017-2021 and rate base growth of 7.4%, 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 2021 planning horizon
- **Capital allocation priorities targeting:**
 - Organic utility growth;
 - Return of capital to shareholders with 5% annual dividend growth through 2020⁽¹⁾,
 - Debt reduction; and,
 - Modest contracted generation investments

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

Additional Disclosures

2018 Adjusted Operating Earnings* Guidance



Expect Q3 2018 Adjusted Operating Earnings* of \$0.80 - \$0.90 per share

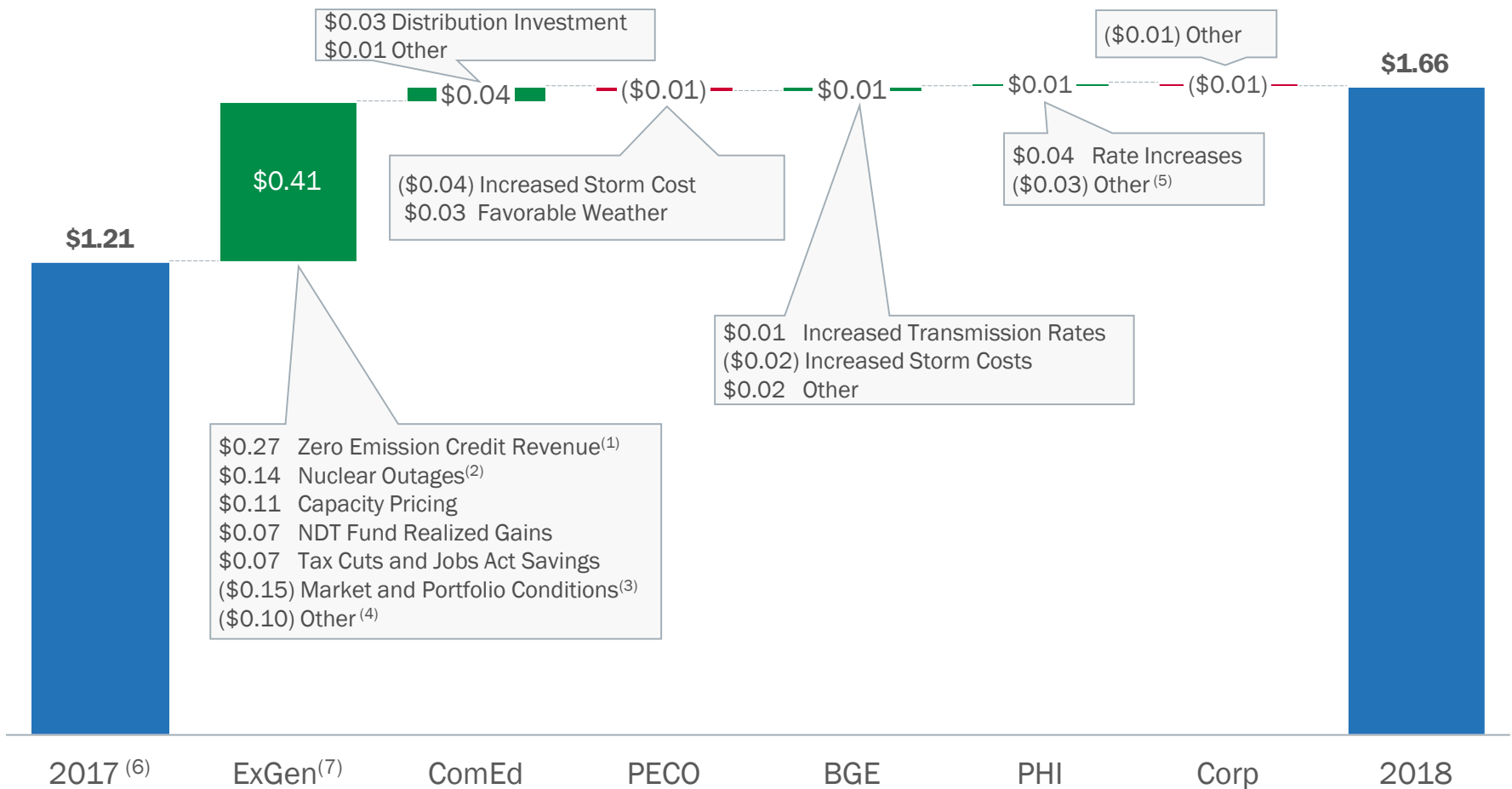
Note: Amounts may not add due to rounding

(1) 2017 results based on 2017 average outstanding shares of 949M

(2) The Registrants' 2017 Adjusted Operating Earnings* have not been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018

(3) 2018 earnings guidance based on expected average outstanding shares of 969M

YTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

- (1) Reflects the impacts of the New York Clean Energy and Illinois Zero Emission Standards, including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017
- (2) Increase in volume due to a decrease in outage days in 2018; additionally operating and maintenance expense decreased due to a decrease in outage days in 2018, excluding Salem
- (3) Primarily lower realized energy prices, the impact of the deconsolidation of EGTP and the conclusion of the Ginna Reliability Support Services Agreement, partially offset by the favorable impacts of Generation's natural gas portfolio
- (4) Primarily reflects noncontrolling interest, partially offset by lower operating and maintenance expense primarily due to the impact of a supplemental NEIL insurance distribution, fewer outage days at Salem, decreased costs related to the sale of Generation's electrical contracting business
- (5) Primarily due to increase in labor and contracting expense
- (6) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018
- (7) Reflects CENG ownership at 100%

2018 Projected Sources and Uses of Cash

(\$M)⁽¹⁾

	BGE	ComEd	PECO	PHI	Total Utilities	ExGen	Corp ⁽⁸⁾	Exelon 2018E	Cash Balance
Beginning Cash Balance*⁽²⁾									1,450
Adjusted Cash Flow from Operations* ⁽²⁾	700	1,475	625	1,100	3,900	3,975	175	8,050	
Base CapEx and Nuclear Fuel ⁽³⁾	0	0	0	0	0	(1,975)	(25)	(2,000)	
Free Cash Flow*	700	1,475	625	1,100	3,900	2,000	150	6,050	
Debt Issuances	300	1,300	700	750	3,050	0	0	3,050	
Debt Retirements	0	(850)	(500)	(275)	(1,625)	0	0	(1,625)	
Project Financing	n/a	n/a	n/a	n/a	n/a	(100)	n/a	(100)	
Equity Issuance/Share Buyback	0	0	0	0	0	0	0	0	
Contribution from Parent	125	450	50	350	975	0	(950)	0	
Other Financing ⁽⁴⁾	100	450	50	(75)	550	25	(100)	475	
Financing*⁽⁵⁾	525	1,375	300	750	2,925	(75)	(1,050)	1,800	
Total Free Cash Flow and Financing	1,225	2,825	925	1,850	6,825	1,950	(900)	7,875	
Utility Investment	(1,000)	(2,125)	(850)	(1,550)	(5,525)	0	0	(5,525)	
ExGen Growth ^(3,6)	0	0	0	0	0	(375)	0	(375)	
Acquisitions and Divestitures	0	0	0	0	0	0	0	0	
Equity Investments	0	0	0	0	0	(25)	0	(25)	
Dividend ⁽⁷⁾	0	0	0	0	0	0	(1,325)	(1,325)	
Other CapEx and Dividend	(1,000)	(2,125)	(850)	(1,550)	(5,525)	(400)	(1,325)	(7,250)	
Total Cash Flow	225	700	75	300	1,300	1,550	(2,250)	600	
Ending Cash Balance*⁽²⁾									2,050

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

Consistent and reliable free cash flows

Operational excellence and financial discipline drives free cash flow reliability

- ✓ Generating \$6.1B of free cash flow*, including \$2B at ExGen and \$3.9B at the Utilities

Supported by a strong balance sheet

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

- ✓ \$1.4B of long-term debt at the utilities, net of refinancing, to support continued growth

Enable growth & value creation

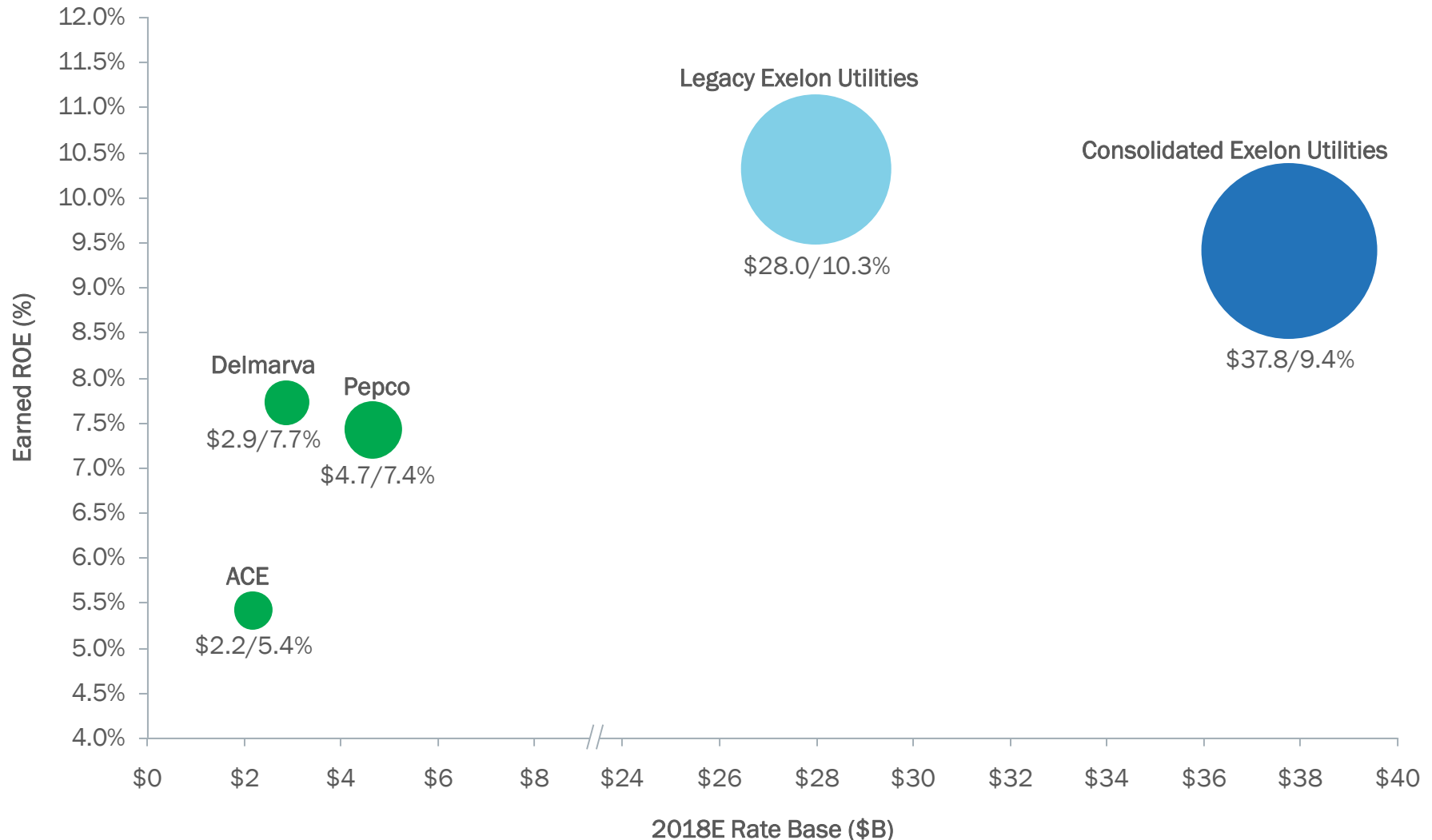
Creating value for customers, communities and shareholders

- ✓ Investing \$5.9B of growth capex, with \$5.5B at the Utilities and \$0.4B at ExGen

Note: Numbers may not add due to rounding

Exelon Utilities Trailing 12 Month Earned ROEs*

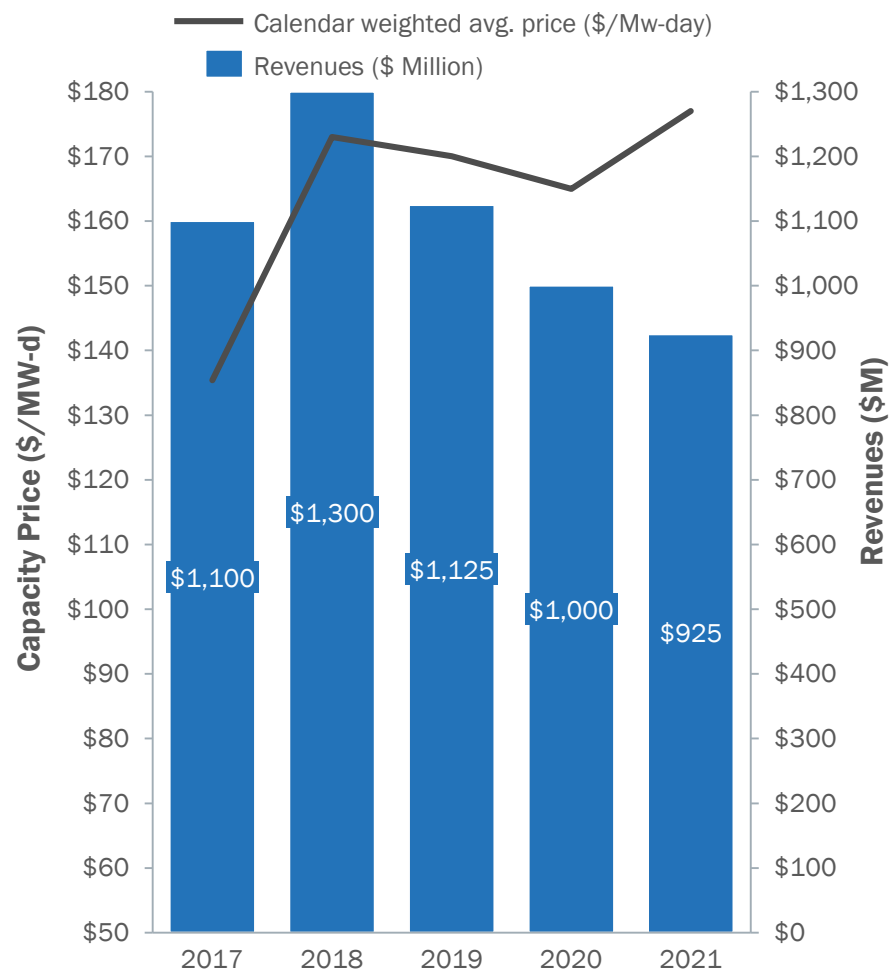
Q2 2018: Trailing Twelve Month Earned ROEs*



Note: Represents the 12-month period ending June 30, 2018. Earned ROEs* represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Electric Transmission). Size of bubble based on rate base.

Capacity Market: PJM

PJM Capacity Revenues^(1,2,3)

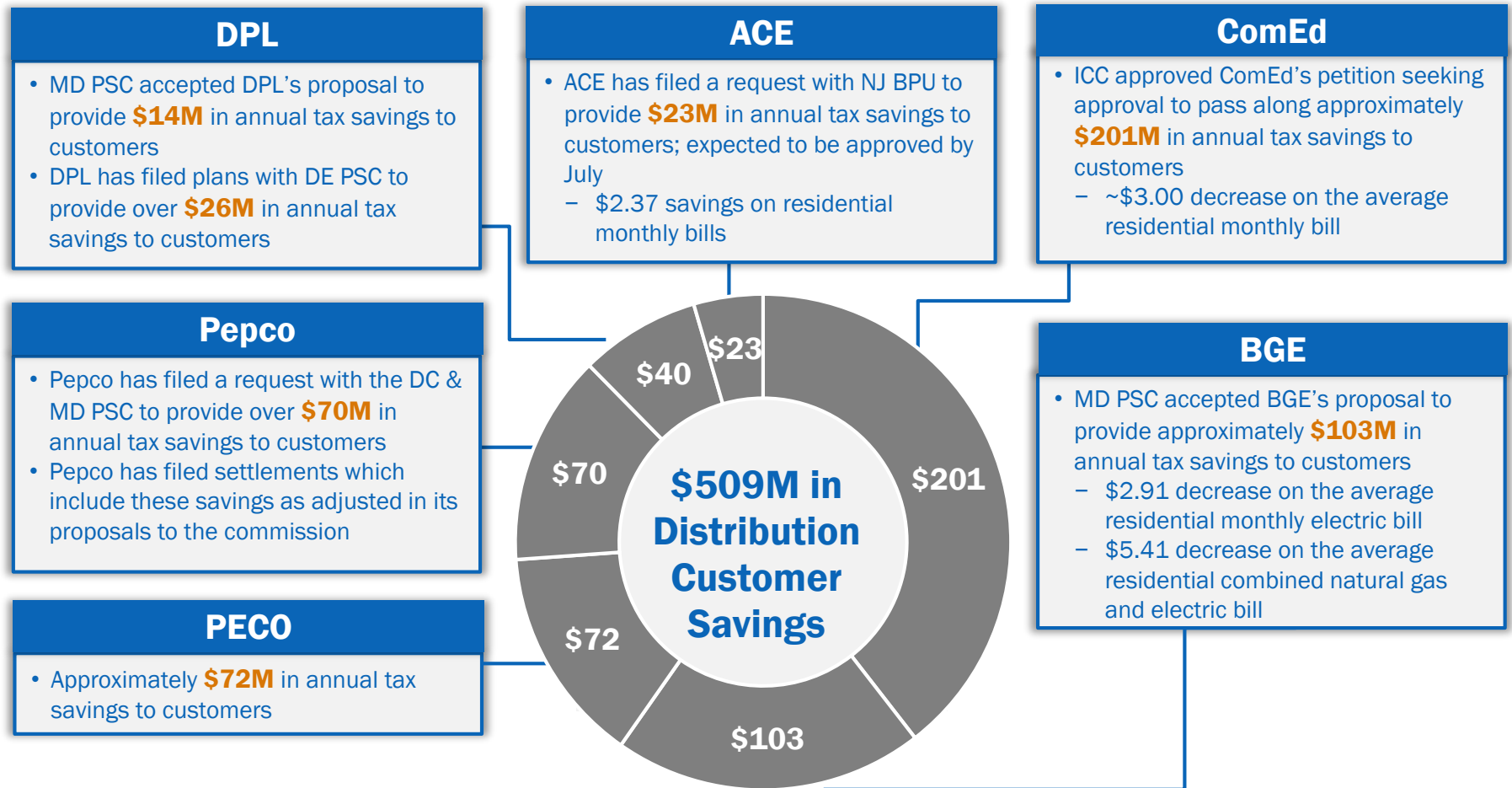


- (1) Revenues reflect capacity cleared in Base, CP transitional & incremental auctions and are for calendar years
 (2) Revenues reflect owned and contracted generation
 (3) Reflects 50.01% ownership at CENG
 (4) Volumes at ownership and rounded

Recent BRA Results

Cleared Volumes (MW) ⁽⁴⁾	2020/2021		2021/2022	
	CP	Price	CP	Price
ComEd				
Nuclear	8,075	\$188	5,175	\$196
Fossil/Other	-	\$188	-	\$196
Subtotal	8,075		5,175	
EMAAC				
Nuclear	4,350	\$188	3,925	\$166
Fossil/Other	2,325	\$188	2,100	\$166
Subtotal	6,675		6,025	
SWMAAC				
Nuclear	850	\$86	850	\$140
Fossil/Other	-	\$86	-	\$140
Subtotal	850		850	
MAAC				
Nuclear	-	\$86	-	\$140
Fossil/Other	225	\$86	225	\$140
Subtotal	225		225	
BGE				
Nuclear	-	\$86	-	\$200
Fossil/Other	375	\$86	400	\$200
Subtotal	375		400	
Rest of RTO				
Nuclear	-	\$77	-	\$140
Fossil/Other	-	\$77	100	\$140
Subtotal	-		100	
PJM Total				
Nuclear	13,275		9,950	
Fossil/Other	2,925		2,825	
Grand Total	16,200		12,775	

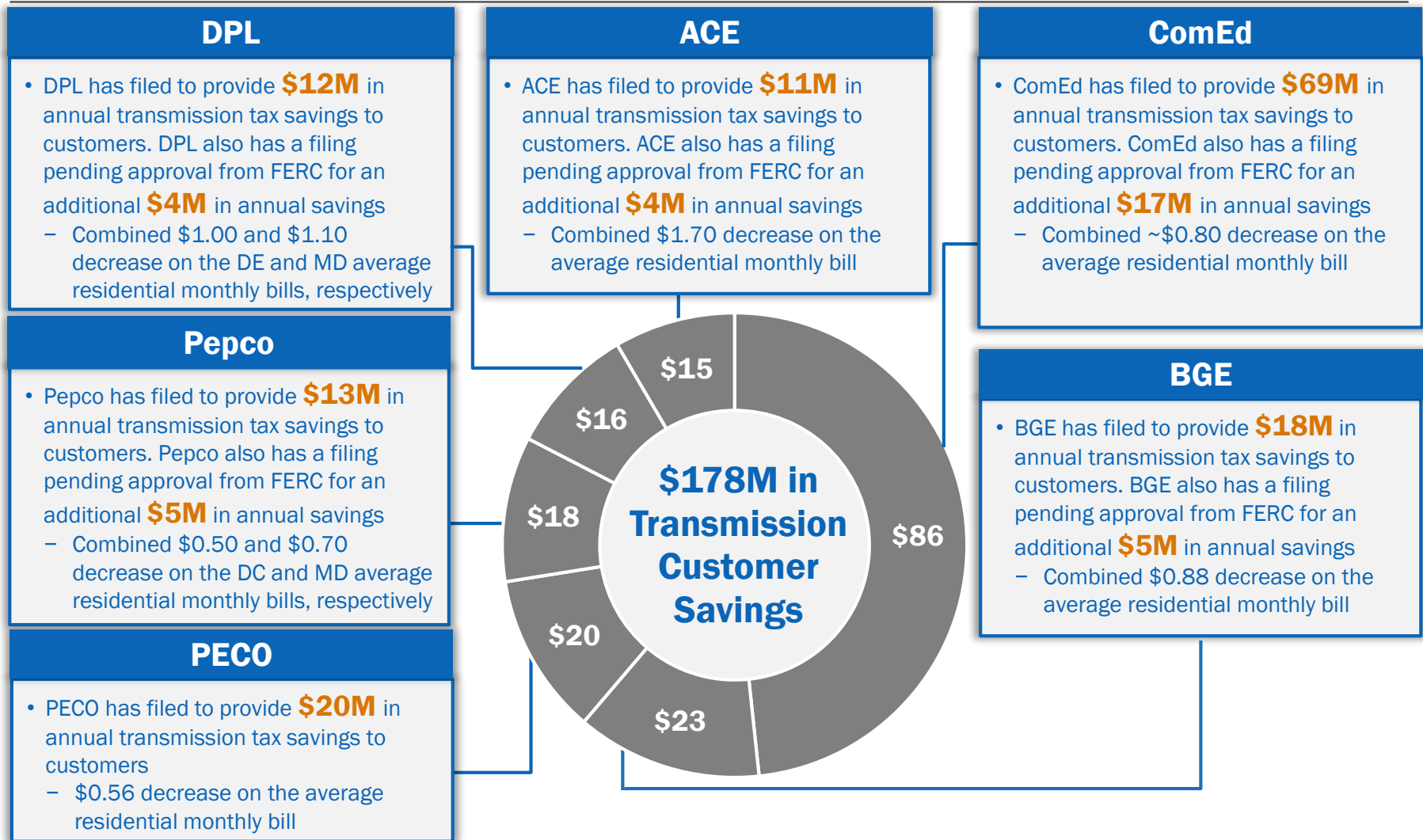
Tax Reform: Distribution-Related Customer Bill Savings



Utility customers across our jurisdictions will benefit from tax reform, saving over \$500M annually through planned and approved distribution bill adjustments

Note: Includes only distribution-related customer savings amounts

Tax Reform: Transmission-Related Customer Bill Savings



Utility customers across our jurisdictions will benefit from tax reform, saving over \$175M annually through planned and approved transmission bill adjustments


Note: Includes only transmission-related customer savings amounts

Exelon Utilities

ComEd Distribution Rate Case Filing

Rate Case Filing Details		Notes
Docket No.	18-0808	<ul style="list-style-type: none"> April 16, 2018, ComEd filed its annual distribution formula rate update with the Illinois Commerce Commission seeking a decrease to distribution base rates The decrease is primarily driven by an adjustment for forecasted tax benefits resulting from federal tax reform, partially offset by continued investment in the electric grid, state tax rate increase, elimination of bonus depreciation and weather/economic impacts
Test Year	January 1, 2017 – December 31, 2017	
Test Period	2017 Actual Costs + 2018 Projected Plant Additions	
Requested Common Equity Ratio	47.11%	
Requested Rate of Return	ROE: 8.69%; ROR: 6.52%	
Proposed Rate Base (Adjusted)	\$10,675M	
Requested Revenue Requirement Decrease	(\$22.9M)	
Residential Total Bill % Decrease	(1%)	


Detailed Rate Case Schedule

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Filed rate case				▲ 4/16/2018								
Intervenor testimony								▲ 6/28/2018				
Rebuttal testimony									▲ 7/23/2018			
Evidentiary hearings										▲ 8/28/2018		
Initial briefs due										▲ 9/11/2018		
Reply briefs due											▲ 9/25/2018	
Commission order expected												12/2018 

Delmarva DE (Electric) Distribution Rate Case Filing

Rate Case Filing Details		Notes
Docket No.	17-0977 – Per Settlement (Black Box)	<ul style="list-style-type: none"> August 17, 2017, Delmarva DE filed an application with Delaware Public Service Commission (DPSC) seeking an increase in electric distribution base rates Size of ask is driven by continued investments in electric distribution system to maintain and increase reliability and customer service June 27, 2018, Delmarva DE filed a non-unanimous settlement agreement and requested a decrease in revenue requirement of (\$6.9M)⁽²⁾
Test Year	January 1, 2017 – December 31, 2017	
Test Period	8 months actual and 4 months estimated	
Requested Common Equity Ratio	50.52% ⁽²⁾	
Requested Rate of Return	ROE: 9.70%; ROR: 6.78% ⁽²⁾	
Proposed Rate Base (Adjusted)	N/A ⁽²⁾	
Requested Revenue Requirement Increase	(\$6.9M) ^(1,2)	
Residential Total Bill % Increase	(1.2%) ⁽²⁾	

Detailed Rate Case Schedule

	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Filed rate case	▲ 8/17/2017																
Settlement agreement	▲ 6/27/2018																
Settlement support testimony	▲ 6/27/2018																
Evidentiary hearings	▲ 6/27/2018																
Commission order expected	 Q3 2018																

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of \$2.5 million on October 16, 2017, and implemented \$5.8M full allowable rates on March 17, 2018, subject to refund

(2) Per non-unanimous Settlement Agreement filed on June 27, 2018. Includes tax benefits from Tax Cuts and Jobs Act.

Delmarva DE (Gas) Distribution Rate Case Filing

Rate Case Filing Details		Notes
Docket No.	17-0978	<ul style="list-style-type: none"> August 17, 2017, Delmarva DE filed an application with Delaware Public Service Commission (DPSC) seeking an increase in gas distribution base rates Size of ask is driven by continued investments in gas distribution system to maintain and increase reliability and customer service Forward looking reliability plant additions through September 2018 (\$1.2M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request
Test Year	January 1, 2017 – December 31, 2017	
Test Period	8 months actual and 4 months estimated	
Requested Common Equity Ratio	50.52%	
Requested Rate of Return	ROE: 10.10%; ROR: 6.98% ⁽²⁾	
Proposed Rate Base (Adjusted)	\$355M ⁽²⁾	
Requested Revenue Requirement Increase	\$3.8M ^(1,2)	
Residential Total Bill % Increase	4.3%	

Detailed Rate Case Schedule

	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Filed rate case	▲ 8/17/2017																
Intervenor testimony	▲ 5/7/2018																
Rebuttal testimony	▲ 7/6/2018																
Evidentiary hearings	9/11/2018 – 9/14/2018 ■																
Initial briefs due	▲ 10/8/2018																
Reply briefs due	▲ 10/22/2018																
Commission order expected	Q4 2018 ■																

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of \$2.5 million on November 1, 2017, and implemented \$3.9M full allowable rates on March 17, 2018, subject to refund

(2) Updated on July 6, 2018. Includes tax benefits from Tax Cuts and Jobs Act.

Pepco DC (Electric) Distribution Rate Case Filing

Rate Case Filing Details		Notes
Docket No.	1150 & 1151 – Per Settlement (Black Box)	<ul style="list-style-type: none"> December 19, 2017, Pepco DC filed an application with Public Service Commission of the District of Columbia (PSCDC) seeking an increase in electric distribution base rates Size of ask is driven by continued investments in electric distribution system to maintain and increase reliability and customer service April 17, 2018, Pepco DC filed a non-unanimous settlement agreement and requested a decrease in revenue requirement of (\$24.1M)⁽¹⁾ Commission order expected to be approved in Q3 2018
Test Year	January 1, 2017 – December 31, 2017	
Test Period	8 months actual and 4 months estimated	
Requested Common Equity Ratio	50.44% ⁽¹⁾	
Requested Rate of Return	ROE: 9.525%; ROR: 7.45% ⁽¹⁾	
Proposed Rate Base (Adjusted)	N/A ⁽¹⁾	
Requested Revenue Requirement decrease	(\$24.1M) ⁽¹⁾	
Residential Total Bill % decrease	(0.7%) ^(1,2)	

Detailed Rate Case Schedule

	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Filed rate case	▲	12/19/2017											
Settlement agreement					▲	4/17/2018							
Settlement support testimony						▲	5/7/2018						
Reply testimony						▲	5/18/2018						
Initial briefs due							▲	6/14/2018					
Commission order expected													Q3 2018

(1) Per non-unanimous Settlement Agreement filed on April 17, 2018. Includes tax benefits from Tax Cuts and Jobs Act. Expected order is based on requested rate effective date.

(2) Modified/Extended Customer Base Rate Credit (CBRC)

Pepco MD (Electric) Distribution Rate Case Filing

Rate Case Filing Details		Notes
Docket No.	9472 – Per Settlement (Black Box)	<ul style="list-style-type: none"> January 2, 2018, Pepco MD filed an application with Maryland Public Service Commission (MDPSC) seeking an increase in electric distribution base rates Size of ask is driven by continued investments in electric distribution system to maintain and increase reliability and customer service April 20, 2018, Pepco MD filed a non-unanimous settlement agreement and requested a decrease in revenue requirement of (\$15.0M)⁽¹⁾ May 31, 2018, MDPSC approved the settlement, which placed rates into effect on and after June 1, 2018
Test Year	January 1, 2017 – December 31, 2017	
Test Period	12 months actual update	
Requested Common Equity Ratio	50.44% ⁽¹⁾	
Requested Rate of Return	ROE: 9.50%; ROR: 7.44% ⁽¹⁾	
Proposed Rate Base (Adjusted)	N/A ⁽¹⁾	
Requested Revenue Requirement Increase	(\$15.0M) ⁽¹⁾	
Residential Total Bill % Increase	(1.3%) ⁽¹⁾	

Detailed Rate Case Schedule

	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Filed rate case	▲ 1/2/2018												
Settlement agreement	▲ 4/20/2018												
Settlement support testimony	▲ 4/27/2018												
Evidentiary hearings	▲ 5/16/2018												
Commission order	▲ 5/31/2018												

(1) Per non-unanimous Settlement Agreement filed on April 20, 2018. Includes tax benefits from Tax Cuts and Jobs Act.

PECO Distribution Rate Case Filing

Rate Case Filing Details		Notes
Docket No.	R-2018-3000164	<ul style="list-style-type: none"> PECO filed an electric distribution base rate case on March 29, 2018 Since January 1, 2016, through the Fully Projected Future Test Year (2019): <ul style="list-style-type: none"> Relatively flat load growth Operating expenses essentially flat Capital investment of \$1.9B Proposed investments would maintain strong reliability performance, strengthen system resiliency, and support physical security and cybersecurity
Test Year	January 1, 2019 – December 31, 2019	
Test Period	12 Months Budget	
Requested Common Equity Ratio	53.39%	
Requested Rate of Return	ROE: 10.95%; ROR: 7.79%	
Proposed Rate Base	\$4,846M	
Requested Revenue Requirement Increase	\$82M ⁽¹⁾	
Residential Total Bill % Increase	3.1%	

Detailed Rate Case Schedule

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Pre-filing notice		▲ 2/27/2018										
Filed rate case			▲ 3/29/2018									
Intervenor testimony						▲ 6/26/2018						
Rebuttal testimony							▲ 7/24/2018					
Evidentiary hearings								■ 8/20/2018 – 8/22/2018				
Initial briefs due								▲ 9/07/2018				
Reply briefs due								▲ 9/17/2018				
Commission order expected											12/2018 ■	

(1) Reflects \$153M revenue requirement less an estimated \$71M in 2019 tax benefit

BGE (Gas) Distribution Rate Case Filing

Rate Case Filing Details		Notes
Docket No.	Case No. 9484	<ul style="list-style-type: none"> Case filed on June 8, 2018 seeking an increase in gas distribution revenues only The increase is primarily driven by infrastructure investments since 2015/2016, and includes moving revenues currently being recovered via the STRIDE surcharge into base rates
Test Year	August 1, 2017 – July 31, 2018	
Test Period	9 months actual and 3 months estimated	
Requested Common Equity Ratio	53.40%	
Requested Rate of Return	ROE: 10.50%; ROR: 7.42%	
Proposed Rate Base (Adjusted)	\$1.7B	
Requested Revenue Requirement Increase	\$85M ⁽¹⁾	
Residential Total Bill % Increase	~3.5% ⁽²⁾	

Detailed Rate Case Schedule

	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Filed rate case	▲ 06/08/2018											
Intervenor testimony	▲ by 09/14/2018											
Rebuttal testimony	▲ by 10/12/2018											
Evidentiary hearings	■ 11/2/2018 – 11/16/2018											
Initial briefs due ⁽³⁾	■ 11/2018											
Reply briefs due	■ 12/2018											
Commission order expected	▲ 01/04/2019											

(1) Reflects \$63M increase and \$22M STRIDE reset

(2) Increase expressed as a percentage of a combined electric and gas residential customer total bill

(3) Briefing schedule will be determined during or at the end of the evidentiary hearing

Exelon Generation Disclosures

June 30, 2018

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

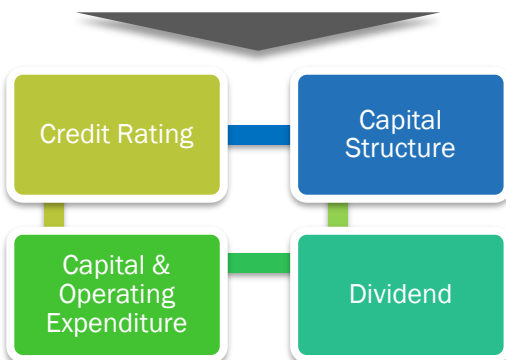
- Ensure stability in near-term cash flows and earnings
- Disciplined approach to hedging
- Tenor aligns with customer preferences and market liquidity
- Multiple channels to market that allow us to maximize margins
- Large open position in outer years to benefit from price upside

Bull / Bear Program

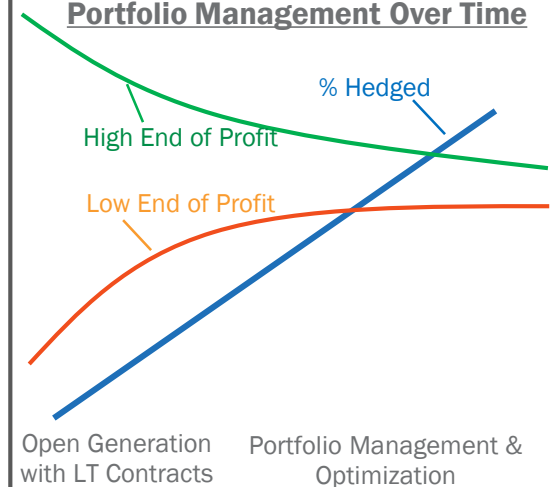
- Ability to exercise fundamental market views to create value within the ratable framework
- Modified timing of hedges versus purely ratable
- Cross-commodity hedging (heat rate positions, options, etc.)
- Delivery locations, regional and zonal spread relationships

Align Hedging & Financials

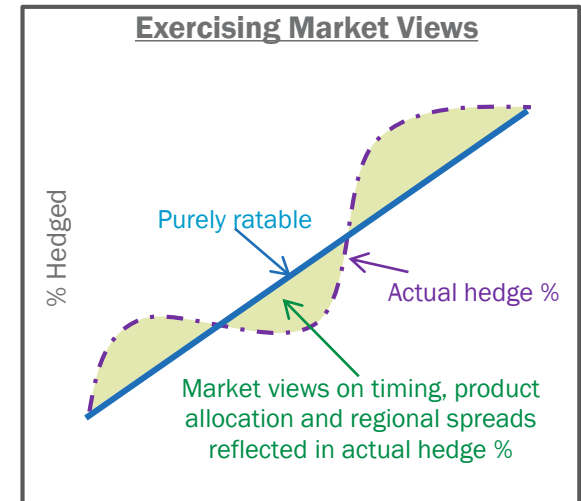
Establishing Minimum Hedge Targets



Portfolio Management Over Time



Exercising Market Views



Protect Balance Sheet

Ensure Earnings Stability

Create Value

Components of Gross Margin Categories

Gross margin linked to power production and sales

Open Gross Margin

- Generation Gross Margin at current market prices, including ancillary revenues, nuclear fuel amortization and fossils fuels expense
- Power Purchase Agreement (PPA) Costs and Revenues
- Provided at a consolidated level for all regions (includes hedged gross margin for South, West and Canada⁽¹⁾)

Capacity and ZEC Revenues

- Expected capacity revenues for generation of electricity
- Expected revenues from Zero Emissions Credits (ZEC)

MtM of Hedges⁽²⁾

- Mark-to-Market (MtM) of power, capacity and ancillary hedges, including cross commodity, retail and wholesale load transactions
- Provided directly at a consolidated level for five major regions. Provided indirectly for each of the five major regions via Effective Realized Energy Price (EREP), reference price, hedge %, expected generation.

“Power” New Business

- Retail, Wholesale planned electric sales
- Portfolio Management new business
- Mid marketing new business

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

Gross margin from other business activities

“Non Power” Executed

- Retail, Wholesale executed gas sales
- Energy Efficiency⁽⁴⁾
- BGE Home⁽⁴⁾
- Distributed Solar

“Non Power” New Business

- Retail, Wholesale planned gas sales
- Energy Efficiency⁽⁴⁾
- BGE Home⁽⁴⁾
- Distributed Solar
- Portfolio Management / origination fuels new business
- Proprietary trading⁽³⁾

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

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

ExGen Disclosures

Gross Margin Category (\$M) ⁽¹⁾	2018	2019	2020
Open Gross Margin (including South, West & Canada hedged GM) ^(2,5)	\$4,700	\$4,050	\$3,800
Capacity and ZEC Revenues ^(2,5,6)	\$2,300	\$2,050	\$1,900
Mark-to-Market of Hedges ^(2,3)	\$400	\$400	\$300
Power New Business / To Go	\$150	\$600	\$800
Non-Power Margins Executed	\$350	\$150	\$100
Non-Power New Business / To Go	\$150	\$350	\$400
Total Gross Margin*^(4,5)	\$8,050	\$7,600	\$7,300

Reference Prices ⁽¹⁾	2018	2019	2020
Henry Hub Natural Gas (\$/MMBtu)	\$2.93	\$2.81	\$2.68
Midwest: NiHub ATC prices (\$/MWh)	\$27.39	\$26.04	\$25.16
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$35.93	\$31.38	\$30.36
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	\$8.91	\$9.70	\$8.43
New York: NY Zone A (\$/MWh)	\$30.80	\$28.21	\$28.55
New England: Mass Hub ATC Spark Spread (\$/MWh) <i>ALQN Gas, 7.5HR, \$0.50 VOM</i>	\$4.89	\$5.12	\$5.83

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

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

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

(4) Based on June 30, 2018, market conditions

(5) Reflects Oyster Creek and TMI retirements by October 2018 and September 2019, respectively. 2018, 2019 and 2020 are adjusted for retaining Handley Generating Station.

(6) 2018 includes \$150M of IL ZEC revenues associated with 2017 production. 2019 and 2020 include the favorable impact of NJ ZEC revenues.

ExGen Disclosures

Generation and Hedges	2018	2019	2020
Exp. Gen (GWh)⁽¹⁾	199,000	202,400	193,100
Midwest	96,700	97,100	96,700
Mid-Atlantic ^(2,6)	60,100	54,100	48,600
ERCOT	20,000	25,900	23,600
New York ^(2,6)	15,900	16,600	15,500
New England	6,300	8,700	8,700
% of Expected Generation Hedged⁽³⁾	97%-100%	71%-74%	41%-44%
Midwest	95%-98%	68%-71%	35%-38%
Mid-Atlantic ^(2,6)	102%-105%	81%-84%	50%-53%
ERCOT	98%-101%	74%-77%	45%-48%
New York ^(2,6)	97%-100%	75%-78%	52%-55%
New England	77%-80%	33%-36%	27%-30%
Effective Realized Energy Price (\$/MWh)⁽⁴⁾			
Midwest	\$30.00	\$29.00	\$29.00
Mid-Atlantic ^(2,6)	\$39.50	\$38.00	\$38.00
ERCOT ⁽⁵⁾	\$1.00	\$3.50	\$2.50
New York ^(2,6)	\$37.00	\$33.00	\$30.00
New England ⁽⁵⁾	\$6.00	\$1.50	\$12.00

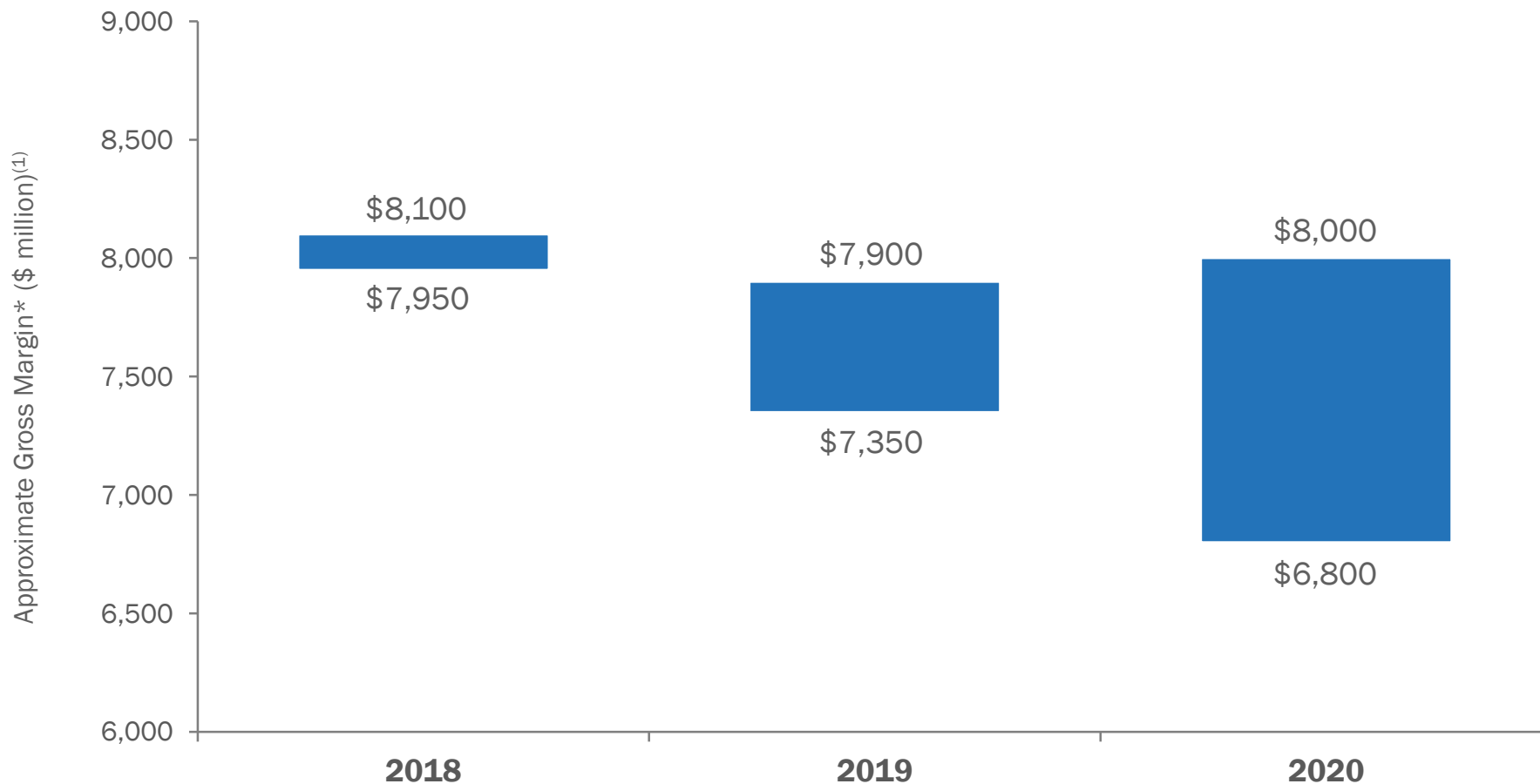
- (1) Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 14 refueling outages in 2018, 11 in 2019, and 14 in 2020 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 94.2%, 94.9% and 93.9% in 2018, 2019, and 2020, respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2019 and 2020 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 and TMI retirements by October 2018 and September 2019, respectively. 2018, 2019 and 2020 are adjusted for retaining Handley Generating Station.

ExGen Hedged Gross Margin* Sensitivities

Gross Margin* Sensitivities (with existing hedges) ⁽¹⁾	2018	2019	2020
Henry Hub Natural Gas (\$/MMBtu)			
+ \$1/MMBtu	\$25	\$335	\$580
- \$1/MMBtu	-	\$(295)	\$(535)
NiHub ATC Energy Price			
+ \$5/MWh	\$5	\$155	\$305
- \$5/MWh	\$(5)	\$(155)	\$(305)
PJM-W ATC Energy Price			
+ \$5/MWh	\$(10)	\$60	\$125
- \$5/MWh	\$15	\$(40)	\$(115)
NYPP Zone A ATC Energy Price			
+ \$5/MWh	-	\$10	\$35
- \$5/MWh	-	\$(15)	\$(35)
Nuclear Capacity Factor			
+/- 1%	+/- \$20	+/- \$35	+/- \$30

(1) Based on June 30, 2018, market conditions and hedged position; gas price sensitivities are based on an assumed gas-power relationship derived from an internal model that is updated periodically; power price sensitivities are derived by adjusting the power price assumption while keeping all other price inputs constant; due to correlation of the various assumptions, the hedged gross margin impact calculated by aggregating individual sensitivities may not be equal to the hedged gross margin impact calculated when correlations between the various assumptions are also considered; sensitivities based on commodity exposure which includes open generation and all committed transactions; excludes EDF's equity share of CENG Joint Venture

ExGen Hedged Gross Margin* Upside/Risk



(1) Represents an approximate range of expected gross margin, taking into account hedges in place, between the 5th and 95th percent confidence levels assuming all unhedged supply is sold into the spot market; approximate gross margin ranges are based upon an internal simulation model and are subject to change based upon market inputs, future transactions and potential modeling changes; these ranges of approximate gross margin in 2019 and 2020 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 June 30, 2018. Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions. Reflects Oyster Creek and TMI retirements by October 2018 and September 2019, respectively. 2018, 2019 and 2020 are adjusted for retaining Handley Generating Station.

Illustrative Example of Modeling Exelon Generation 2019 Total Gross Margin*

ZECJ-FIN-21

PUBLIC

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	←————— \$4.05 billion —————→					
(B)	Capacity and ZEC	←————— \$2.05 billion —————→					
(C)	Expected Generation (TWh)	97.1	54.1	25.9	16.6	8.7	
(D)	Hedge % (assuming mid-point of range)	69.5%	82.5%	75.5%	76.5%	34.5%	
(E=C*D)	Hedged Volume (TWh)	67.5	44.6	19.6	12.7	3.0	
(F)	Effective Realized Energy Price (\$/MWh)	\$29.00	\$38.00	\$3.50	\$33.00	\$1.50	
(G)	Reference Price (\$/MWh)	\$26.04	\$31.38	\$9.70	\$28.21	\$5.12	
(H=F-G)	Difference (\$/MWh)	\$2.96	\$6.62	(\$6.20)	\$4.79	(\$3.62)	
(I=E*H)	Mark-to-Market value of hedges (\$ million) ⁽¹⁾	\$200	\$295	(\$120)	\$60	(\$10)	
(J=A+B+I)	Hedged Gross Margin (\$ million)			\$6,500			
(K)	Power New Business / To Go (\$ million)			\$600			
(L)	Non-Power Margins Executed (\$ million)			\$150			
(M)	Non-Power New Business / To Go (\$ million)			\$350			
(N=J+K+L+M)	Total Gross Margin*			\$7,600 million			

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

Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in \$M)⁽¹⁾	2018	2019	2020
Revenue Net of Purchased Power and Fuel Expense^{*(2,3)}	\$8,500	\$8,075	\$7,750
Other Revenues ⁽⁴⁾	\$(200)	\$(175)	\$(200)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses	\$(250)	\$(300)	\$(250)
Total Gross Margin* (Non-GAAP)	\$8,050	\$7,600	\$7,300

Key ExGen Modeling Inputs (in \$M)^(1,5)	2018
Other ⁽⁶⁾	\$250
Adjusted O&M*	\$(4,625)
Taxes Other Than Income (TOTI) ⁽⁷⁾	\$(375)
Depreciation & Amortization ^{*(8)}	\$(1,125)
Interest Expense	\$(400)
Effective Tax Rate	22.0%

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

(2) ExGen does not forecast the GAAP components of RNF separately, as to do so would be unduly burdensome. RNF also includes the RNF of our proportionate ownership share of CENG.

(3) Excludes the Mark-to-Market impact of economic hedging activities due to the volatility and unpredictability of the future changes to power prices

(4) Other Revenues reflects primarily revenues from JExel Nuclear JV, variable interest entities, funds collected through revenues for decommissioning the former PECO nuclear plants through regulated rates, and gross receipts tax revenues

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

(6) Other reflects Other Revenues excluding gross receipts tax revenues, includes nuclear decommissioning trust fund earnings from unregulated sites, and includes the minority interest in ExGen Renewables JV and Bloom. Other for 2018 is favorable due to NDTF realized gains that may not occur in 2019 and 2020.

(7) TOTI excludes gross receipts tax of \$150M

(8) 2019 Depreciation & Amortization is flat to 2018 and 2020 is favorable \$50M due to nuclear plant retirements

Appendix

Reconciliation of Non-GAAP Measures

Q2 QTD GAAP EPS Reconciliation

Three Months Ended June 30, 2017	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2017 GAAP (Loss) Earnings Per Share⁽¹⁾	(\$0.25)	\$0.13	\$0.09	\$0.05	\$0.07	\$0.02	\$0.10
Mark-to-market impact of economic hedging activities	0.12	-	-	-	-	-	0.12
Unrealized gains related to NDT fund investments	(0.05)	-	-	-	-	-	(0.05)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	0.01	-	-	-	-	-	0.02
Long-lived asset impairments	0.29	-	-	-	-	-	0.29
Plant retirements and divestitures	0.07	-	-	-	-	-	0.07
Cost management program	-	-	-	-	-	-	0.01
Like-kind exchange tax position	-	0.02	-	-	-	(0.05)	(0.03)
Noncontrolling interest	0.02	-	-	-	-	-	0.02
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.23	\$0.15	\$0.10	\$0.05	\$0.07	\$(0.03)	\$0.56

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

(1) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018

Q2 QTD GAAP EPS Reconciliation (continued)

Three Months Ended June 30, 2018	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2018 GAAP Earnings (Loss) Per Share	\$0.18	\$0.17	\$0.10	\$0.05	\$0.09	(\$0.04)	\$0.56
Mark-to-market impact of economic hedging activities	(0.07)	-	-	-	-	-	(0.07)
Unrealized losses related to NDT fund investments	0.08	-	-	-	-	-	0.08
Long-lived asset impairments	0.03	-	-	-	-	-	0.03
Plant retirements and divestitures	0.14	-	-	-	-	-	0.14
Cost management program	0.01	-	-	-	-	-	0.01
Change in environmental liabilities	0.01	-	-	-	-	-	0.01
Reassessment of deferred income taxes	-	-	-	-	-	(0.01)	(0.01)
Noncontrolling interests	(0.04)	-	-	-	-	-	(0.04)
2018 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.34	\$0.17	\$0.10	\$0.05	\$0.09	(\$0.05)	\$0.71

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

Q2 YTD GAAP EPS Reconciliation

Six Months Ended June 30, 2017	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2017 GAAP Earnings Per Share⁽¹⁾	\$0.20	\$0.28	\$0.23	\$0.18	\$0.22	\$0.06	\$1.17
Mark-to-market impact of economic hedging activities	0.15	-	-	-	-	-	0.15
Unrealized gains related to NDT fund investments	(0.15)	-	-	-	-	-	(0.15)
Amortization of commodity contract intangibles	0.02	-	-	-	-	-	0.02
Merger and integration costs	0.04	-	-	-	-	-	0.04
Merger commitments	(0.02)	-	-	-	(0.06)	(0.06)	(0.15)
Long-lived asset impairments	0.29	-	-	-	-	-	0.29
Plant retirements and divestitures	0.07	-	-	-	-	-	0.07
Cost management program	0.01	-	-	-	-	-	0.01
Bargain purchase gain	(0.24)	-	-	-	-	-	(0.24)
Like-kind exchange tax position	-	0.02	-	-	-	(0.05)	(0.03)
Reassessment of deferred income taxes	-	-	-	-	-	(0.02)	(0.02)
Tax settlements	(0.01)	-	-	-	-	-	(0.01)
Noncontrolling interest	0.06	-	-	-	-	-	0.06
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.41	\$0.30	\$0.23	\$0.18	\$0.15	(\$0.08)	\$1.21

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

(1) Certain immaterial prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income have been recast to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018

Q2 YTD GAAP EPS Reconciliation (continued)

Six Months Ended June 30, 2018	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2018 GAAP Earnings (Loss) Per Share	\$0.32	\$0.34	\$0.22	\$0.18	\$0.15	(\$0.06)	\$1.16
Mark-to-market impact of economic hedging activities	0.13	-	-	-	-	-	0.13
Unrealized losses related to NDT fund investments	0.15	-	-	-	-	-	0.15
Long-lived asset impairments	0.03	-	-	-	-	-	0.03
Plant retirements and divestitures	0.23	-	-	-	-	-	0.23
Cost management program	0.01	-	-	-	-	-	0.02
Change in environmental liabilities	0.01	-	-	-	-	-	0.01
Reassessment of deferred income taxes	-	-	-	-	-	(0.01)	(0.01)
Noncontrolling interests	(0.06)	-	-	-	-	-	(0.06)
2018 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.83	\$0.34	\$0.22	\$0.19	\$0.16	(\$0.07)	\$1.66

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

Projected GAAP to Operating Adjustments

- **Exelon's projected 2018 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
 - Certain merger and integration costs
 - Impairments of certain wind projects at Generation
 - Certain costs related to plant retirements
 - Costs incurred related to a cost management program
 - Generation's noncontrolling interest, primarily related to CENG exclusion items
 - One-time impacts of adopting new accounting standards
 - Other unusual items

GAAP to Non-GAAP Reconciliations⁽¹⁾

$$\text{Exelon FFO/Debt}^{(2)} = \frac{\text{FFO (a)}}{\text{Adjusted Debt (b)}}$$

Exelon FFO Calculation⁽²⁾

GAAP Operating Income
 + Depreciation & Amortization
 = EBITDA
 - GAAP Interest Expense
 +/- GAAP Current Income Tax (Expense)/Benefit
 + Nuclear Fuel Amortization
 +/- GAAP to Operating Adjustments
 +/- Other S&P Adjustments
 = **FFO (a)**

Exelon Adjusted Debt Calculation⁽¹⁾

Long-Term Debt (including current maturities)
 + Short-Term Debt
 + Purchase Power Agreement and Operating Lease Imputed Debt
 + Pension/OPEB Imputed Debt (after-tax)
 - Off-Credit Treatment of Non-Recourse Debt
 - Cash on Balance Sheet * 75%
 +/- Other S&P Adjustments
 = **Adjusted Debt (b)**

(1) Due to the forward-looking nature of some forecasted non-GAAP measures, information to reconcile the forecasted adjusted (non-GAAP) measures to the most directly comparable GAAP measure may not be currently available; therefore, management is unable to reconcile these measures

(2) Calculated using S&P Methodology. Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment

GAAP to Non-GAAP Reconciliations⁽¹⁾

$$\text{ExGen Debt/EBITDA} = \frac{\text{Net Debt (a)}}{\text{Operating EBITDA (b)}}$$

$$\text{ExGen Debt/EBITDA Excluding Non-Recourse} = \frac{\text{Net Debt (c)}}{\text{Operating EBITDA (d)}}$$

ExGen Net Debt Calculation

Long-Term Debt (including current maturities)
 + Short-Term Debt
- Cash on Balance Sheet
= Net Debt (a)

ExGen Net Debt Calculation Excluding Non-Recourse

Long-Term Debt (including current maturities)
 + Short-Term Debt
- Cash on Balance Sheet
- Non-Recourse Debt
= Net Debt Excluding Non-Recourse (c)

ExGen Operating EBITDA Calculation

GAAP Operating Income
+ Depreciation & Amortization
 = EBITDA
+/- GAAP to Operating Adjustments
= Operating EBITDA (b)

ExGen Operating EBITDA Calculation Excluding Non-Recourse

GAAP Operating Income
+ Depreciation & Amortization
 = EBITDA
+/- GAAP to Operating Adjustments
- EBITDA from Projects Financed by Non-Recourse Debt
= Operating EBITDA Excluding Non-Recourse (d)

(1) Due to the forward-looking nature of some forecasted non-GAAP measures, information to reconcile the forecasted adjusted (non-GAAP) measures to the most directly comparable GAAP measure may not be currently available; therefore, management is unable to reconcile these measures

GAAP to Non-GAAP Reconciliations

Q2 2018 Operating ROE Reconciliation (\$M)	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP)	\$57	\$102	\$189	\$1,384	\$1,731
Operating Exclusions	\$0	\$8	\$3	\$2	\$13
Adjusted Operating Earnings	\$57	\$109	\$192	\$1,386	\$1,744
Average Equity	\$1,044	\$1,425	\$2,577	\$13,439	\$18,485
Operating ROE (Adjusted Operating Earnings/Average Equity)	5.4%	7.7%	7.4%	10.3%	9.4%

Q1 2018 Operating ROE Reconciliation (\$M)	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP)	\$56	\$94	\$178	\$1,321	\$1,650
Operating Exclusions	\$0	\$7	(\$1)	\$26	\$32
Adjusted Operating Earnings	\$56	\$101	\$177	\$1,347	\$1,682
Average Equity	\$1,046	\$1,341	\$2,433	\$13,164	\$17,985
Operating ROE (Adjusted Operating Earnings/Average Equity)	5.4%	7.6%	7.3%	10.2%	9.4%

ExGen Adjusted O&M Reconciliation (\$M) ⁽¹⁾	2018
GAAP O&M	\$5,375
Decommissioning ⁽²⁾	50
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses ⁽³⁾	(275)
O&M for managed plants that are partially owned	(400)
Other	(125)
Adjusted O&M (Non-GAAP)	\$4,625

(1) All amounts rounded to the nearest \$25M. Items may not sum due to rounding.

(2) Reflects earnings neutral O&M

(3) Reflects the direct cost of sales of certain businesses, which are included in Total Gross Margin*

GAAP to Non-GAAP Reconciliations

2018 Adjusted Cash from Ops Calculation (\$M) ⁽¹⁾	BGE	ComEd	PECO	PHI	ExGen	Other	Exelon
Net cash flows provided by operating activities (GAAP)	\$700	\$1,475	\$625	\$1,100	\$4,250	\$175	\$8,325
Other cash from investing activities	-	-	-	-	(\$275)	-	(\$275)
Counterparty collateral activity	-	-	-	-	-	-	-
Adjusted Cash Flow from Operations	\$700	\$1,475	\$625	\$1,100	\$3,975	\$175	\$8,050

2018 Cash From Financing Calculation (\$M) ⁽¹⁾	BGE	ComEd	PECO	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	\$325	\$900	(\$0)	\$450	(\$1,075)	(\$125)	\$475
Dividends paid on common stock	\$200	\$450	\$300	\$300	\$1,000	(\$950)	\$1,325
Financing Cash Flow	\$525	\$1,375	\$300	\$750	(\$75)	(\$1,050)	\$1,800

Exelon Total Cash Flow Reconciliation ⁽¹⁾	2018
GAAP Beginning Cash Balance	\$900
Adjustment for Cash Collateral Posted	\$550
Adjusted Beginning Cash Balance ⁽³⁾	\$1,450
Net Change in Cash (GAAP) ⁽²⁾	\$600
Adjusted Ending Cash Balance ⁽³⁾	\$2,050
Adjustment for Cash Collateral Posted	(\$550)
GAAP Ending Cash Balance	\$1,525

(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