

Earnings Conference Call 3rd Quarter 2018

November 1, 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 Third 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

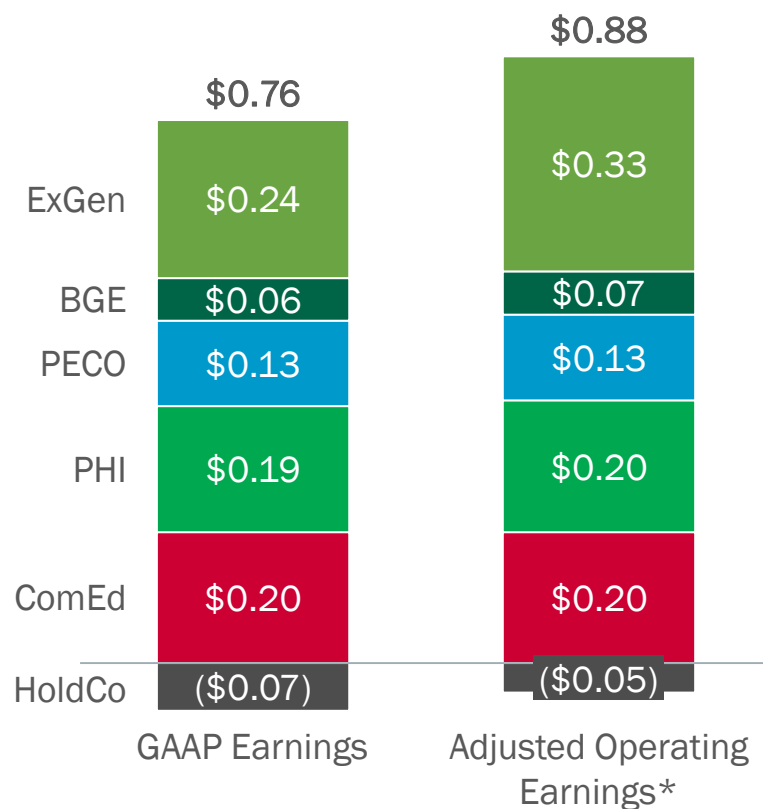
Non-GAAP Financial Measures Continued

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 39 of this presentation.

Q3 2018 EPS Results^(1,2)



- GAAP earnings were \$0.76/share in Q3 2018 vs. \$0.85/share in Q3 2017
- Adjusted operating earnings* were \$0.88/share in Q3 2018 vs. \$0.85/share in Q3 2017, which is at the upper end of our guidance range of \$0.80-\$0.90/share

(1) Amounts may not sum 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	Q3 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		

- Reliability performance remains strong in CAIDI and SAIFI across the utilities, while safety performance continues to improve
- Gas odor response remains strong in top decile across the utilities
- Customer operation metrics are strong across all utilities with BGE and ComEd performing in top decile for Customer Satisfaction and PHI in top decile for Service Level

Q1	Q2
Q3	Q4

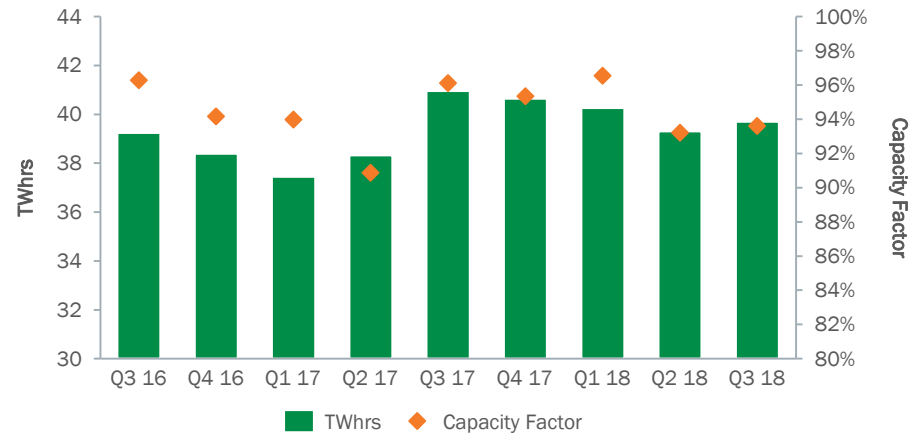
(1) 2.5 Beta SAIFI is YE projection

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

Exelon Generation Operational Performance

Exelon Nuclear Fleet⁽²⁾

- Best in class performance across our Nuclear fleet:
 - Q3 2018 Nuclear Capacity Factor: 93.6%
 - Owned and operated Q3 2018 production of 39.7 TWh⁽²⁾



Fossil and Renewable Fleet

- Q3 2018 Renewables energy capture: 95.7%
- Q3 2018 Power dispatch match: 95.8%
- Wolf Hollow II and Colorado Bend unit 7 have returned to service. Colorado Bend unit 8 will return to service in early November.

Key Updates

Cost Reductions

Committing to \$200M in additional cost reductions with a targeted run-rate date of 2021:

- \$100M at ExGen
- \$100M at Business Services Company – approximately 50% of savings will be allocated to ExGen

Savings due to our focus on improving efficiencies, eliminating redundancies, and leveraging innovation and technologies

More than \$900M in announced savings between 2015 – 2021 relative to original plan

ZECS

Seventh and Second Circuit Court of Appeals Uphold ZEC Programs:

- On September 13, the Seventh Circuit Court of Appeals affirmed the dismissal of the Illinois ZEC complaint, upholding the legality of the program
- On September 27, the Second Circuit affirmed dismissal of New York ZEC complaint
- On October 9, the Seventh Circuit denied the petitioners' request for rehearing

New Jersey:

- Board of Public Utilities completed meetings and hearings on implementation of ZEC program
- On September 20, utilities filed tariff changes to recover ZEC related charges
- ZEC applications are due on December 19

Market Reforms

FERC Capacity Market Proceeding:

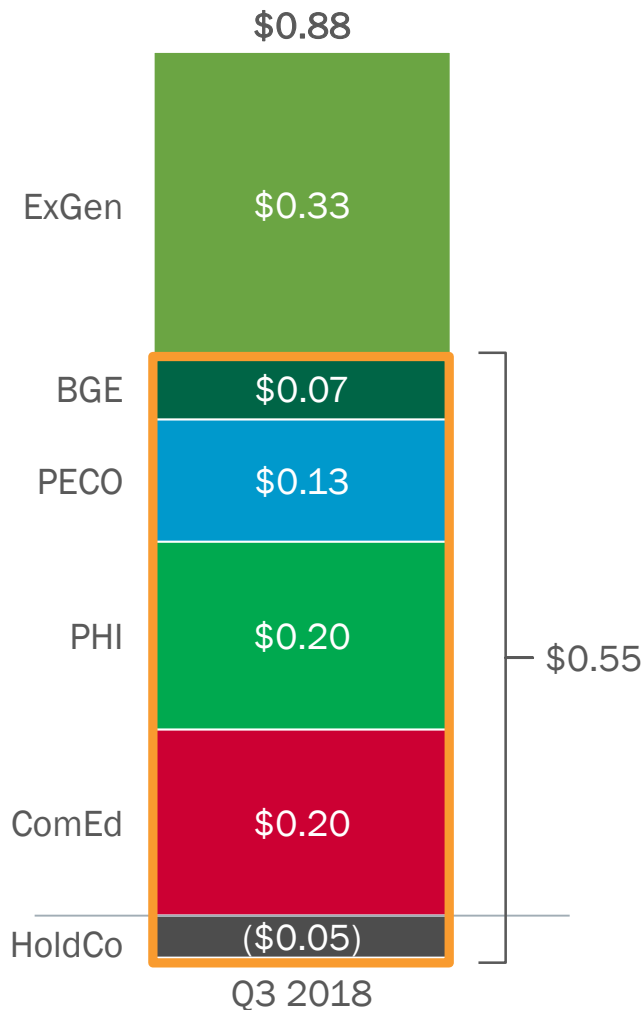
- On October 2, stakeholders filed comments in response to FERC's request in its June order
- Exelon joined a coalition proposal supported by rate payer advocates, attorneys general, environmental organizations, renewable advocates and other nuclear generators
- Reply comments are due on November 6
- PJM requests FERC action in January 2019 to provide adequate time for the August 2019 PJM capacity auction

Fast Start:

- PJM fast start pricing has been fully briefed; awaiting decision from FERC

3rd Quarter Adjusted Operating Earnings* Drivers

Q3 2018 Adjusted Operating EPS* Results



Q3 2018 vs. Guidance of \$0.80 - \$0.90

Exelon Utilities

- ↑ Favorable weather
- ↑ Reduced storm activity

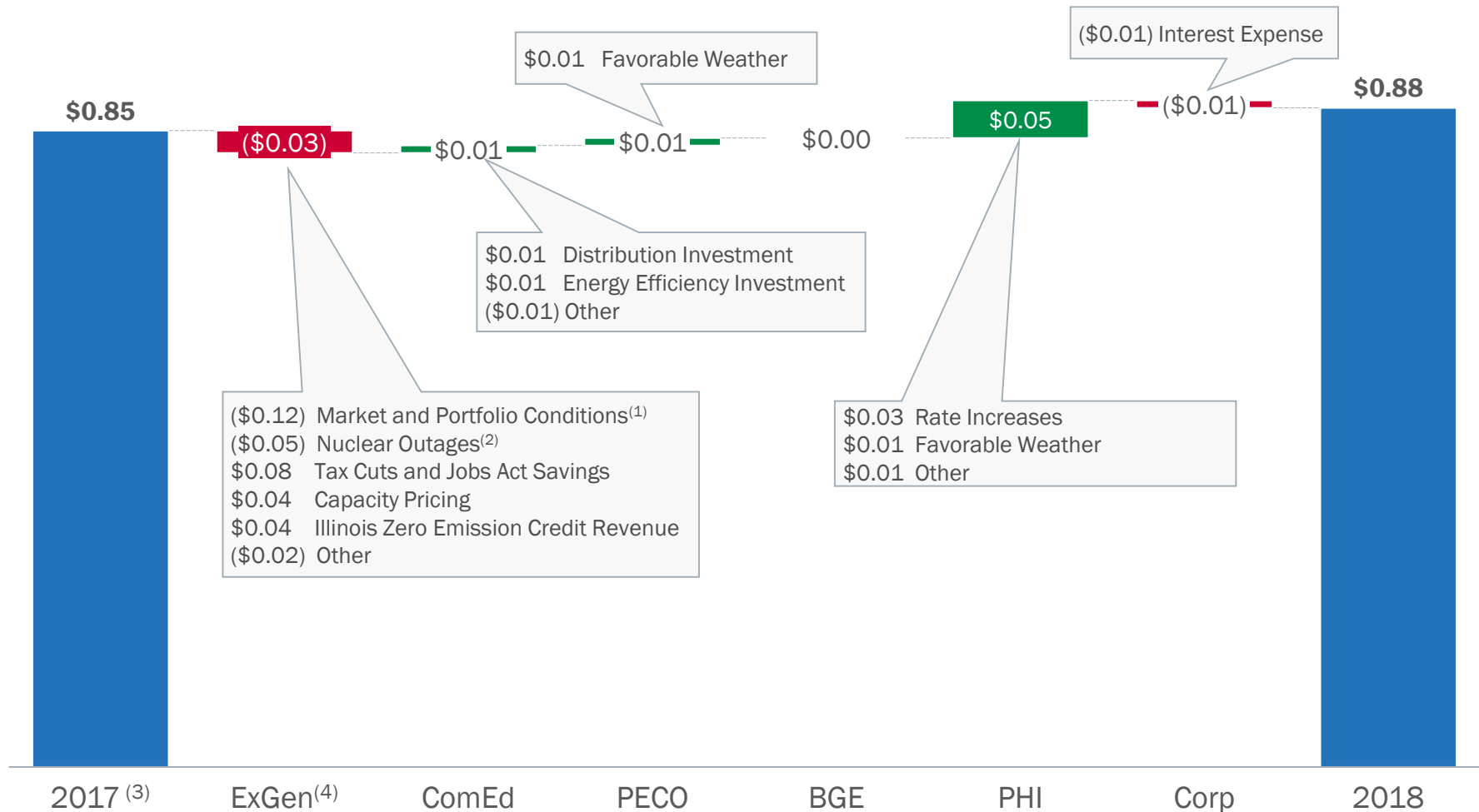
Exelon Generation

- ↑ NDT realized gains⁽¹⁾
- ↓ Generation performance
- ↓ Market conditions
- ↓ Higher transmission costs

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) Primarily the absence of EGTP revenues net of purchased power and fuel expense resulting from its deconsolidation in the fourth quarter of 2017 and lower realized energy prices
- (2) Decrease in volume due to an increase in outage days in 2018; additionally operating and maintenance expense increased due to an increase in outage days in 2018, excluding Salem
- (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) Drivers reflect CENG ownership at 100%

Raising Lower End of 2018 Guidance Range



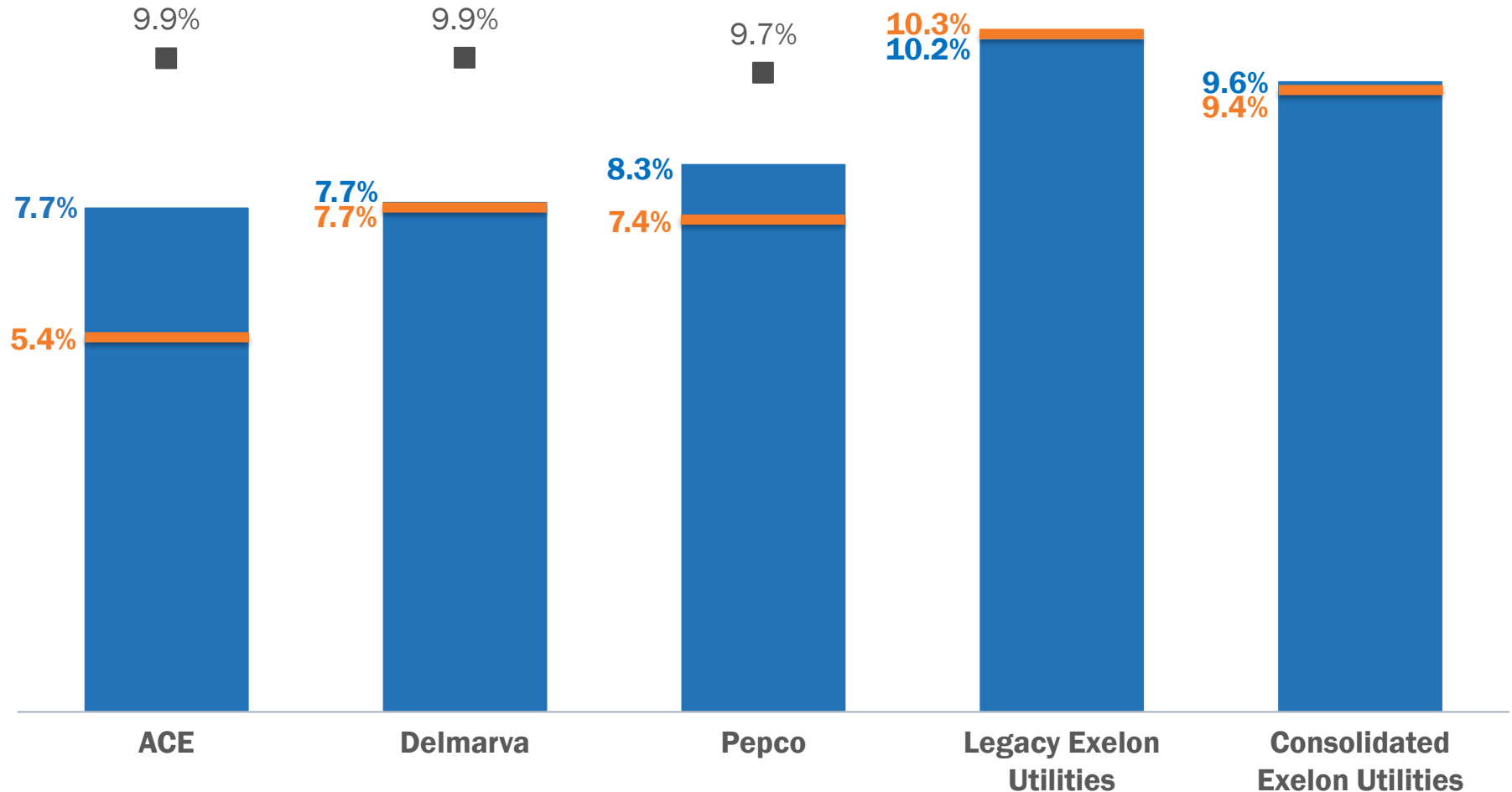
Note: Amounts may not sum due to rounding

(1) 2018 Adjusted Operating Earnings* guidance based on expected average outstanding shares of 969M

Trailing Twelve Month Earned ROEs* vs Allowed ROE

Trailing Twelve Month Earned ROEs*

■ Allowed ROE — Q2 2018 TTM Earned ROE ■ Q3 2018 TTM Earned ROE



Note: Represents the twelve-month periods ending June 30, 2018 and September 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

	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Revenue Requirement	Requested ROE / Equity Ratio	Expected Order
ComEd	RT	EH	IB RB			FO							(\$24.1M) ^(1,8)	8.69% / 47.11%	Dec 2018
Delmarva Electric (DE)		FO											(\$6.9M) ^(1,3)	9.70% / 50.52%	August 21, 2018
Delmarva Gas (DE)	RT		EH SA			FO							(\$3.5M) ^(1,4)	9.70% / 50.52%	Q4 2018
Pepco Electric (DC)		FO											(\$24.1M) ^(1,10)	9.525% / 50.44%	August 9, 2018
PECO Electric	RT	EH SA	IB RB			FO							\$25M ^(1,5,9)	N/A	Dec 2018
BGE ⁽²⁾ Gas			IT	RT	EH IB	RB	FO						\$82.4M ⁽⁶⁾	10.5% / 52.85% ⁽⁶⁾	Jan 2019
ACE ⁽⁷⁾		CF			IT	RT		EH	IB RB				\$109.3M ⁽¹⁾	10.10% / 50.22%	Q3 2019
<div> <div>CF</div> Rate case filed <div>RT</div> Rebuttal testimony <div>IB</div> Initial briefs <div>FO</div> Final commission order </div> <div> <div>IT</div> Intervenor direct testimony <div>EH</div> Evidentiary hearings <div>RB</div> Reply briefs <div>SA</div> Settlement agreement </div>															

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 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. Per partial Settlement Agreement filed on September 7, 2018. Includes tax benefits from Tax Cuts and Jobs Act.
- (5) On October 18, 2018, the presiding Administrative Law Judges issued the Recommended Decision that the Settlement Agreement reached with all active parties be approved without modification. The black box settlement does not stipulate any ROE, Equity Ratio and Rate Base. The rate case settlement agreement is subject to PaPUC approval expected in December, with rates effective January 1, 2018.
- (6) Reflects \$60.7M increase and \$21.7M STRIDE reset. Test year updated for May-July 2018 actuals and reflects long-term debt issuance made in September 2018.
- (7) Procedural schedule as proposed by the Company. ACE plans to put interim rates in effect nine months after the filing date, subject to refund, as allowed by the regulations.
- (8) Original filing amount was (\$22.9M). Recent discovery period removed additional (\$1.2M) of revenue requirement to limit issues in the proceeding.
- (9) Reflects \$96M revenue requirement less an estimated \$71M in 2019 tax benefit
- (10) Per Settlement Agreement filed on April 17, 2018. Includes tax benefits from Tax Cuts and Jobs Act.

Utility CapEx Update

ComEd Completes AMI Smart Meter Installations

- **Forecasted project capital cost:**
 - \$920M; more than \$20M under budget
 - AMI installations are part of the broader \$2.6B Energy Infrastructure Modernization Act program
- **In service date:**
 - Over 4M meters have been exchanged as of September 2018, which is 3 years ahead of the original schedule
- **Project scope:**
 - Replaces existing legacy electric meters with digital smart meters and a wireless communications network
 - AMI improves grid reliability and enables operational efficiencies, while also empowering customers to take greater control of their energy consumption using online management tools and programs that offer efficiency and savings opportunities
 - Customers enrolled in the Peak Time Savings and Hourly Pricing programs have saved more than \$5.6M and \$19.5M, respectively



ACE's Churchtown Substation Expansion Project

- **Forecasted project cost:**
 - \$50M
- **In service date:**
 - Improvements completed in April 2018; retirement of Deepwater Substation completed in October 2018
- **Project scope:**
 - Includes equipment upgrades for reliability and 230, 138 and 69 kV expansion for additional transmission capacity
 - Expansion improves reliability for our customers by replacing and upgrading obsolete equipment and by expanding regional transmission capacity



Exelon Generation: Gross Margin Update

Gross Margin Category (\$M) ⁽¹⁾	September 30, 2018			Change from June 30, 2018		
	2018	2019	2020	2018	2019	2020
Open Gross Margin ^(2,5) (including South, West, Canada hedged gross margin)	\$4,800	\$4,300	\$3,900	\$100	\$250	\$100
Capacity and ZEC Revenues ^(2,5,6)	\$2,300	\$2,050	\$1,900	-	-	-
Mark-to-Market of Hedges ^(2,3)	\$350	\$250	\$250	\$(50)	\$(150)	\$(50)
Power New Business / To Go	\$100	\$550	\$800	\$(50)	\$(50)	-
Non-Power Margins Executed	\$400	\$200	\$150	\$50	\$50	\$50
Non-Power New Business / To Go	\$100	\$300	\$350	\$(50)	\$(50)	\$(50)
Total Gross Margin*^(4,5)	\$8,050	\$7,650	\$7,350	-	\$50	\$50

Recent Developments

- Open Gross Margin (“OGM”) is up in 2018 due to higher NiHub, West Hub, and NY Zone A prices, partly offset by weaker ERCOT spark spreads
- 2019 and 2020 OGM is up due to stronger ERCOT spark spreads and higher West Hub prices; 2019 OGM is also up on higher NiHub and New York Zone A prices
- Mark-to-Market of Hedges is down in all years on higher prices, offset by the execution of Power New Business in 2018/2019
- Executed \$50M of Non-Power New Business in all years
- Behind ratable hedging position reflects the upside we see in power prices
 - ~9-12% 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

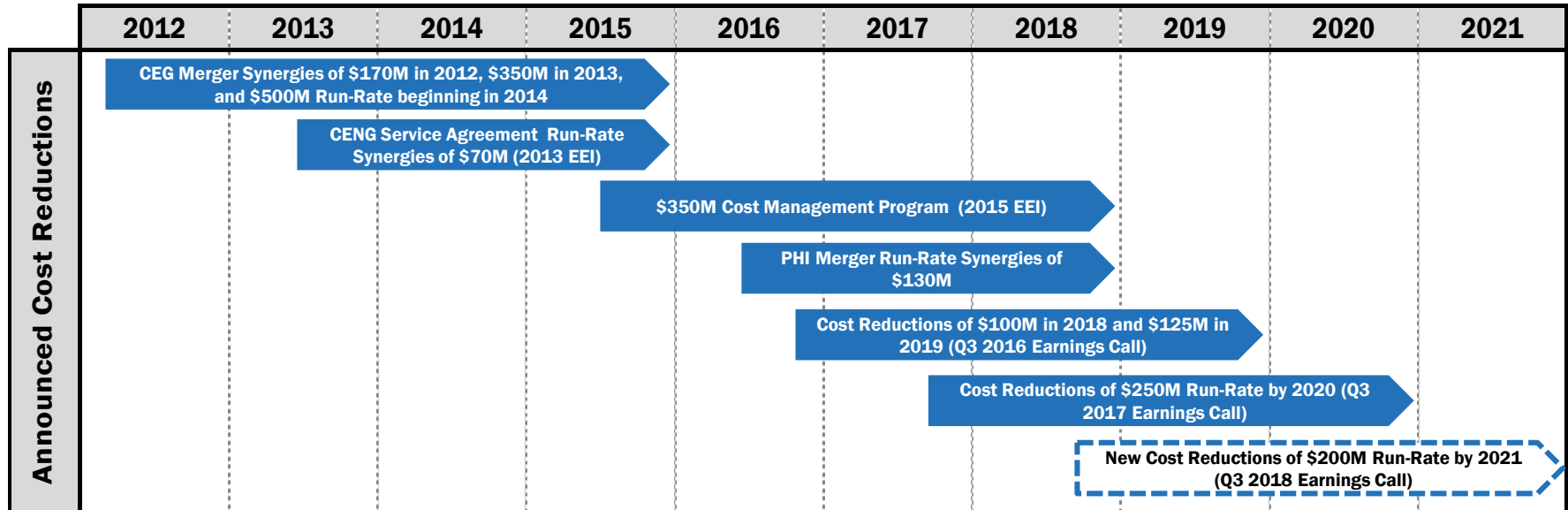
(4) Based on September 30, 2018, market conditions

(5) Reflects Oyster Creek retirement in September 2018 and TMI retirement by September 2019

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

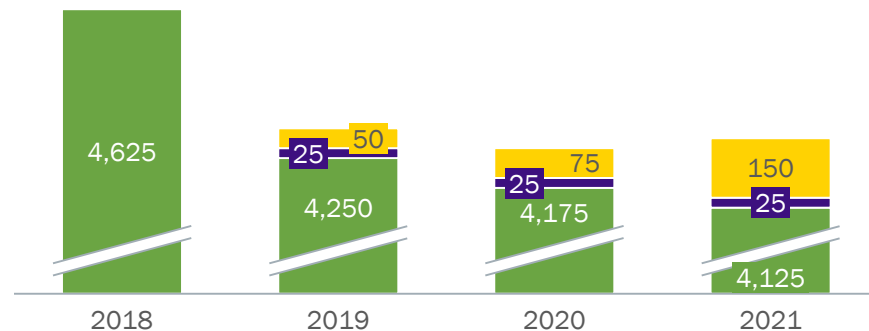
Cost Management is Integral to Our Business Strategy

ExGen and BSC Cost Reductions Since Constellation Merger



ExGen Forecast O&M* Q3 2018 (\$M)

■ Q3 '18 Cost Reductions ■ Other Adjustments⁽¹⁾ ■ ExGen Total O&M



(1) Primarily pension updates due to higher interest rates

Key Commentary

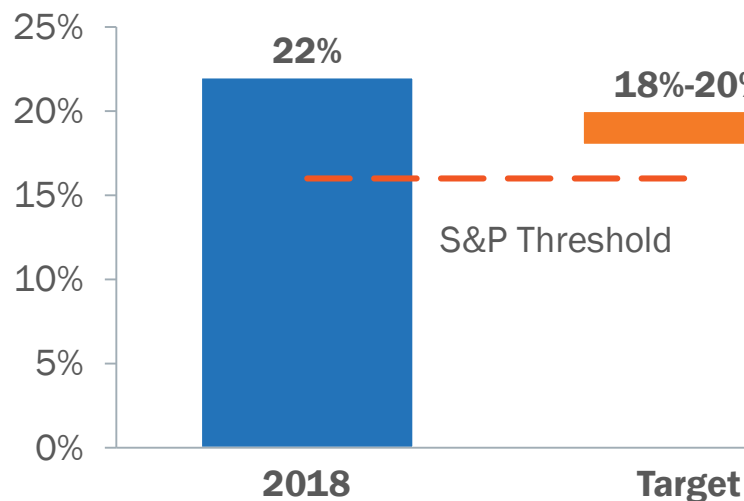
- Committing to \$200M in additional cost reductions
 - \$100M at ExGen
 - \$100M at Business Services Company – approximately 50% of savings will be allocated to ExGen
- **Since 2015, Exelon has announced more than \$900M of cost reductions**

Maintaining Strong Investment Grade Credit Ratings is a Top Financial Priority

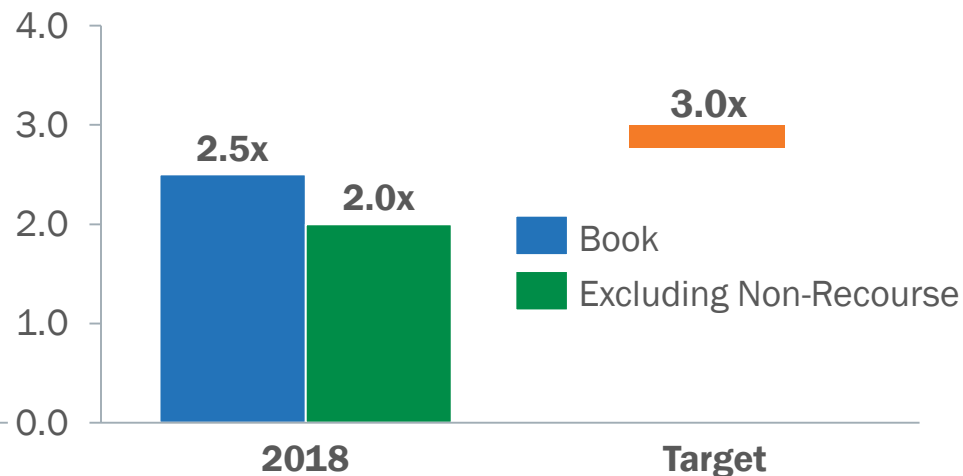
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PUBLIC

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



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



Credit Ratings by Operating Company

Current Ratings ^(2,3)	ExCorp	ExGen	ComEd	PECO	BGE	ACE	DPL	Pepco
Moody's	Baa2	Baa2	A1	Aa3	A3	A3 ⁽³⁾	A2	A2
S&P	BBB- ⁽³⁾	BBB ⁽³⁾	A- ⁽³⁾	A- ⁽³⁾	A- ⁽³⁾	A ⁽³⁾	A ⁽³⁾	A ⁽³⁾
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 November 1, 2018, for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco

(3) Exelon Corp and all subsidiaries are on "Positive" outlook at S&P; Exelon Corp, PECO, and BGE are on "Positive" outlook at Fitch; 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*

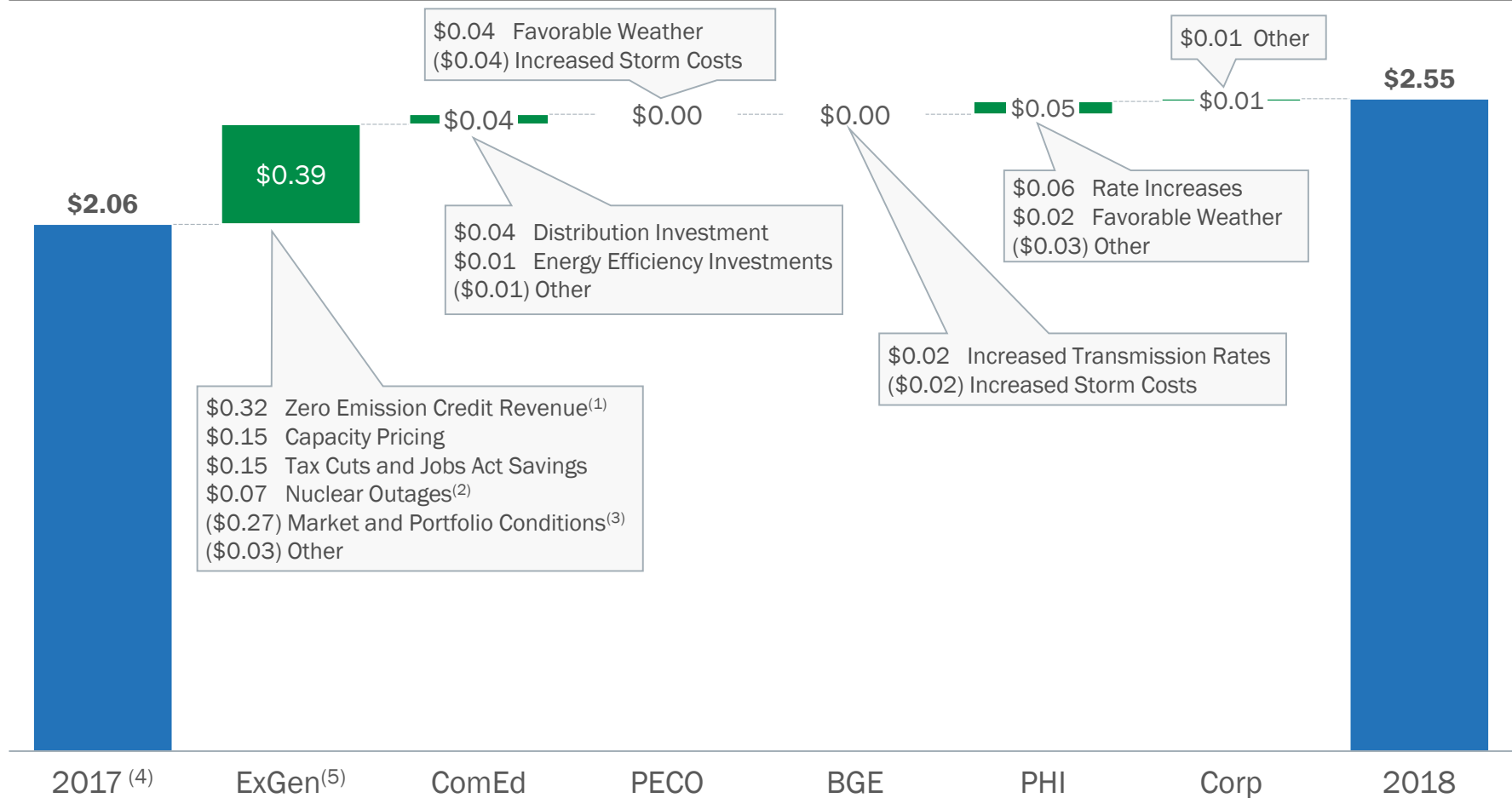
The Exelon Value Proposition

- **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

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 and the absence of EGTP revenues net of purchased power and fuel expense resulting from its deconsolidation in the fourth quarter of 2017
- (4) 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
- (5) Drivers reflect 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⁾	750	1,650	650	1,100	4,175	3,800	175	8,150	
Base CapEx and Nuclear Fuel ⁽³⁾	0	0	0	0	0	(1,975)	(50)	(2,025)	
Free Cash Flow*	750	1,650	650	1,100	4,175	1,825	125	6,125	
Debt Issuances	300	1,350	700	750	3,100	0	0	3,100	
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	100	500	50	350	1,000	0	(1,000)	0	
Other Financing ⁽⁴⁾	50	0	50	(125)	(25)	50	(50)	(25)	
Financing*⁽⁵⁾	475	1,000	300	700	2,475	(50)	(1,050)	1,375	
Total Free Cash Flow and Financing	1,225	2,650	950	1,800	6,625	1,775	(925)	7,475	
Utility Investment	(1,000)	(2,125)	(850)	(1,500)	(5,475)	0	0	(5,475)	
ExGen Growth ^(3,6)	0	0	0	0	0	(350)	0	(350)	
Acquisitions and Divestitures	0	0	0	0	0	(25)	0	(25)	
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)	(1,500)	(5,475)	(400)	(1,325)	(7,225)	
Total Cash Flow	225	525	100	275	1,150	1,375	(2,250)	275	
Ending Cash Balance*⁽²⁾									1,725

- (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 changes in money pool borrowings, tax sharing from the parent, 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 \$1.8B at ExGen and \$4.2B at the Utilities

Supported by a strong balance sheet

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

- ✓ \$1.5B of long-term debt at the utilities, net of refinancing, to support continued growth

Enable growth & value creation

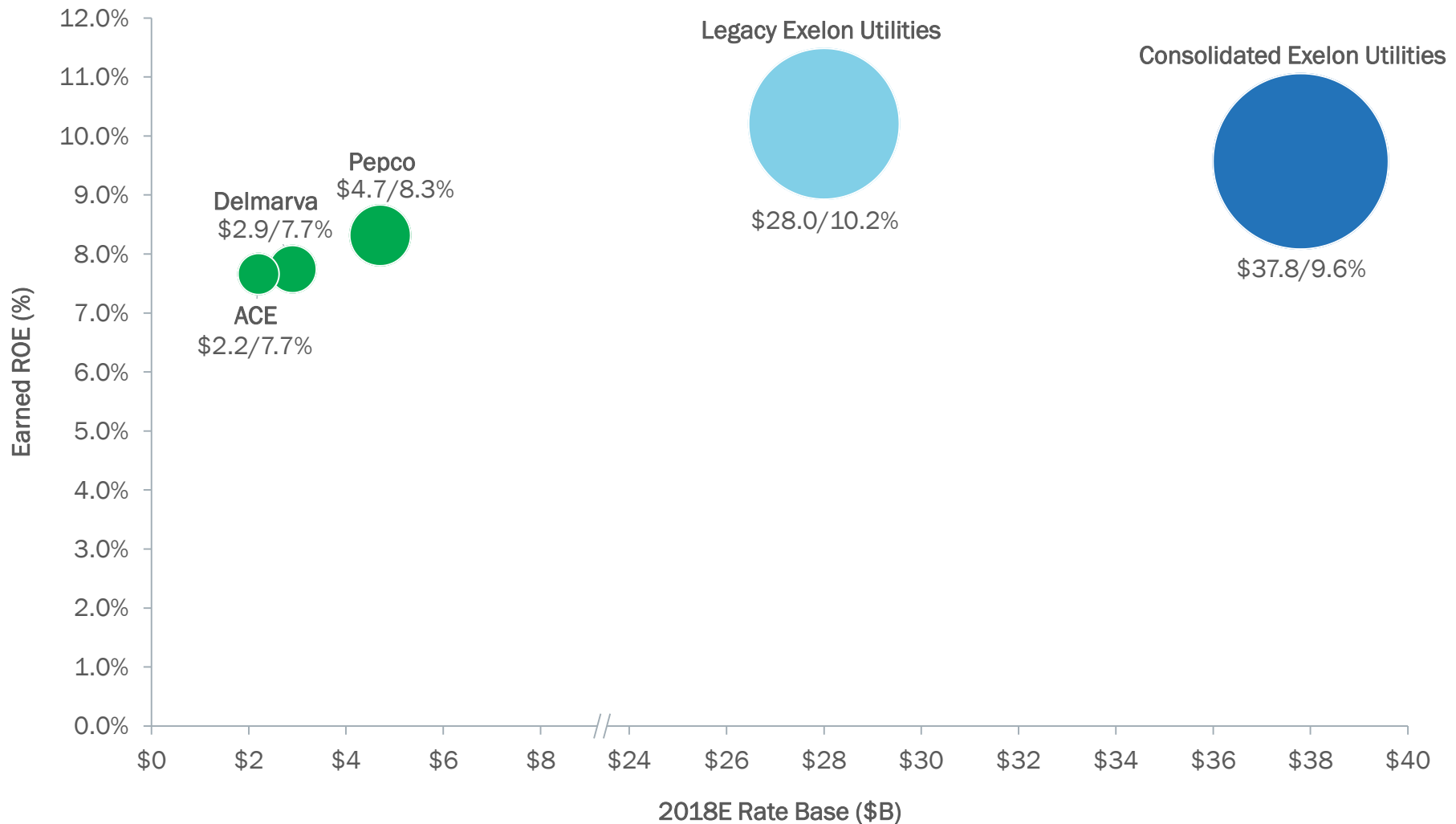
Creating value for customers, communities and shareholders

- ✓ 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 Twelve Month Earned ROEs*

Q3 2018: Trailing Twelve Month Earned ROEs*



Note: Represents the twelve-month period ending September 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.

Shared Principles for FRR-RS Have Broad Support From Many Sectors

ZECJ-FIN-21

PUBLIC

Renewable Community



Consumer Advocates



Shared Principles

An FRR-RS mechanism should:

- Protect customers from paying duplicate capacity
- Preserve states' abilities to achieve clean energy policy goals

FERC should:

- Require Fixed Resource Requirement – Resource Specific (FRR-RS) to allow load serving entities to buy capacity from all state-incentivized resources and receive full capacity credit for doing so
- Allow for a smooth transition by giving states enough time to work through any difficult implementation issues before fully imposing the MOPR

Industry Stakeholders



Environmental NGOs



Numerous parties endorsed a shared set of principles and many others favorably cited those principles in their comments in Docket EL18-178

Exelon Utilities

ACE Distribution Rate Case Filing

Rate Case Filing Details		Notes
Docket No.	ER-18080925	<ul style="list-style-type: none"> August 21 2018, ACE filed a distribution base rate case with the New Jersey Board of Public Utilities (BPU) to increase distribution base rates Size of ask is primarily driven by increased depreciation expense, continued investment in infrastructure to maintain and improve reliability and customer satisfaction, and higher O&M costs Forward looking additions through June 2019 (\$9.8M of revenue requirement based on 10.10% ROE) included in revenue requirement request Interim rates expected to go in effect in May 2019, subject to refund, as allowed by the regulations
Test Year	January 1, 2018 – December 31, 2018	
Test Period	6 months actual and 6 months estimated	
Requested Common Equity Ratio	50.22%	
Requested Rate of Return	ROE: 10.10%; ROR: 7.45%	
Proposed Rate Base (Adjusted)	\$1.6B	
Requested Revenue Requirement Increase	\$109.3M ⁽¹⁾	
Residential Total Bill % Increase	9.55%	

Detailed Rate Case Schedule⁽²⁾

	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
Filed rate case	▲ 8/21/2018												
Intervenor testimony	▲ 11/19/2018												
Rebuttal testimony	▲ 12/21/2018												
Evidentiary hearings	■ 2/4/2019 – 2/15/2019												
Initial briefs due	▲ 3/8/2019												
Reply briefs due	▲ 3/22/2019												
Commission order expected	Q3 2019 ▲												

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

(2) Procedural schedule as proposed by the Company

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	12 months actual	
Requested Common Equity Ratio	52.85% ⁽¹⁾	
Requested Rate of Return	ROE: 10.5%; ROR: 7.46% ⁽¹⁾	
Proposed Rate Base (Adjusted)	\$1.7B	
Requested Revenue Requirement Increase	\$82.4M ⁽¹⁾	
Residential Total Bill % Increase	~3.4% ⁽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	▲ 09/14/2018											
Rebuttal testimony	▲ 10/12/2018											
Evidentiary hearings	■ 11/2/2018 – 11/16/2018											
Initial briefs due ⁽³⁾	■ 11/2018											
Reply briefs due ⁽³⁾	■ 12/2018											
Commission order expected	▲ 01/04/2019											

(1) Reflects \$60.7M increase and \$21.7M STRIDE reset. Test year updated for May-July 2018 actuals and reflects long-term debt issuance made in September 2018.

(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

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	(\$24.1M) ^(1,2)	
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	■

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

(2) Original filing amount was (\$22.9M). Recent discovery period removed additional (\$1.2M) of revenue requirement to limit issues in the proceeding.

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 Settlement Agreement and requested a decrease in revenue requirement of (\$6.9M)⁽²⁾ August 21, 2018, DPSC approved the settlement
Test Year	January 1, 2017 – December 31, 2017	
Test Period	8 months actual and 4 months estimated	
Common Equity Ratio	50.52% ⁽²⁾	
Rate of Return	ROE: 9.70%; ROR: 6.78% ⁽²⁾	
Rate Base (Adjusted)	N/A	
Revenue Requirement Decrease	(\$6.9M) ^(1,2)	
Residential Total Bill % Decrease	(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	▲ 8/21/2018																


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

(2) 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 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 - 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 gas distribution base rates September 7, 2018, Delmarva Power filed a partial gas Settlement Agreement and requested a decrease in revenue requirement of (\$3.5M)⁽²⁾ The partial Settlement Agreement resolves all issues except a \$3.5M regulatory asset related to the Interface Management Unit (IMU) batteries
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	
Requested Revenue Requirement Decrease	(\$3.5M) ^(1,2)	
Residential Total Bill % Decrease	(2.6%) ⁽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																
Intervenor testimony	▲ 5/7/2018																
Rebuttal testimony	▲ 7/6/2018																
Settlement agreement	▲ 9/7/2018																
Settlement support testimony	▲ 9/7/2018																
Evidentiary hearings	▲ 9/7/2018																
Commission order expected	Q4 2018 																

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

(2) 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. Per partial Settlement Agreement filed on September 7, 2018. Includes tax benefits from Tax Cuts and Jobs Act.

PECO Distribution Rate Case Filing

Rate Case Settlement 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 On October 18, 2018 the presiding Administrative Law Judges issued the Recommended Decision that the Settlement Agreement reached with all active parties be approved without modification. The black box settlement does not stipulate any ROE, Equity Ratio and Rate Base. The rate case settlement agreement is subject to PaPUC approval expected in December, with rates effective January 1, 2019 The settlement amount of \$96M⁽²⁾ represents 63% of the \$153M ask. This is in line with prior PA electric distribution rate case outcomes.
Test Year	January 1, 2019 – December 31, 2019	
Test Period	12 Months Budget	
Common Equity Ratio	N/A	
Rate of Return	ROE: N/A; ROR: N/A	
Rate Base	N/A	
Revenue Requirement Increase	\$25M ^(1,2)	
Residential Total Bill % Increase	1.2%	

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								▲ 8/21/2018				
Initial briefs filed									▲ 9/07/2018			
Reply briefs filed										▲ 9/17/2018		
Commission order expected											12/01/2018	

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

(2) Reflects \$96M revenue requirement less an estimated \$71M in 2019 tax benefit

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 settlement agreement and requested a decrease in revenue requirement of (\$24.1M)⁽²⁾ August 9, 2018, PSCDC approved settlement agreement which placed rates in effect on August 13, 2018
Test Year	January 1, 2017 – December 31, 2017	
Test Period	8 months actual and 4 months estimated	
Requested Common Equity Ratio	50.44% ⁽²⁾	
Requested Rate of Return	ROE: 9.525%; ROR: 7.45% ⁽²⁾	
Proposed Rate Base (Adjusted)	N/A	
Requested Revenue Requirement Decrease	(\$24.1M) ^(1,2)	
Residential Total Bill % Decrease	(0.7%) ^(2,3)	

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							▲ 6/14/2018						
Commission order									▲ 8/9/2018				

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

(2) Per Settlement Agreement filed on April 17, 2018. Includes tax benefits from Tax Cuts and Jobs Act.

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

Exelon Generation Disclosures

September 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

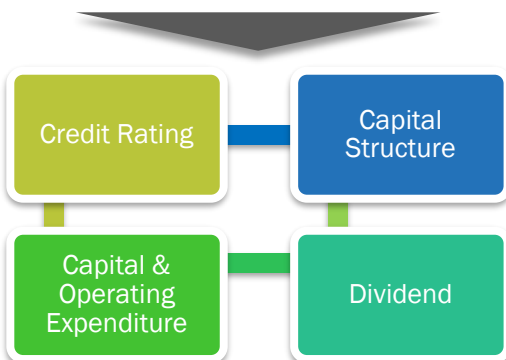
- Ensure stability in near-term cash flows and earnings
- Disciplined approach to hedging
- Tenor aligns with customer preferences and market liquidity
- Multiple channels to market that allow us to maximize margins
- Large open position in outer years to benefit from price upside

Bull / Bear Program

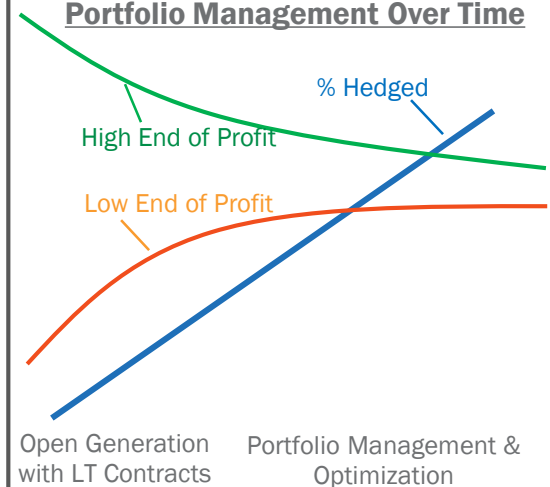
- Ability to exercise fundamental market views to create value within the ratable framework
- Modified timing of hedges versus purely ratable
- Cross-commodity hedging (heat rate positions, options, etc.)
- Delivery locations, regional and zonal spread relationships

Align Hedging & Financials

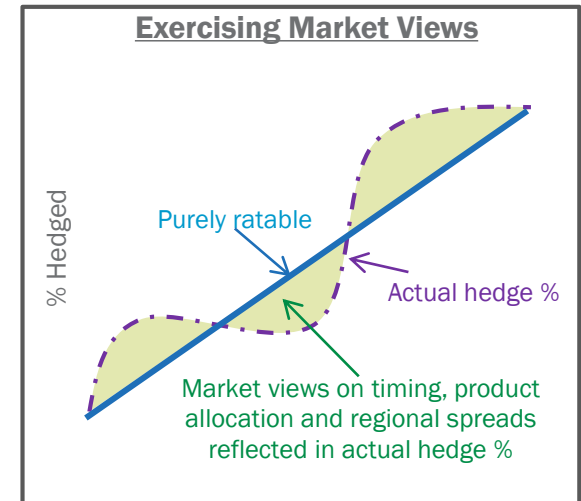
Establishing Minimum Hedge Targets



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

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

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

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

ExGen Disclosures

Gross Margin Category (\$M) ⁽¹⁾	2018	2019	2020
Open Gross Margin (including South, West & Canada hedged GM) ^(2,5)	\$4,800	\$4,300	\$3,900
Capacity and ZEC Revenues ^(2,5,6)	\$2,300	\$2,050	\$1,900
Mark-to-Market of Hedges ^(2,3)	\$350	\$250	\$250
Power New Business / To Go	\$100	\$550	\$800
Non-Power Margins Executed	\$400	\$200	\$150
Non-Power New Business / To Go	\$100	\$300	\$350
Total Gross Margin*^(4,5)	\$8,050	\$7,650	\$7,350

Reference Prices ⁽¹⁾	2018	2019	2020
Henry Hub Natural Gas (\$/MMBtu)	\$2.94	\$2.78	\$2.65
Midwest: NiHub ATC prices (\$/MWh)	\$27.62	\$26.24	\$24.92
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$36.54	\$33.53	\$31.59
ERCOT-N ATC Spark Spread (\$/MWh)	\$4.06	\$11.50	\$10.30
<i>HSC Gas, 7.2HR, \$2.50 VOM</i>			
New York: NY Zone A (\$/MWh)	\$31.86	\$29.49	\$27.89
New England: Mass Hub ATC Spark Spread (\$/MWh)	\$6.80	\$6.88	\$6.27
<i>ALQN Gas, 7.5HR, \$0.50 VOM</i>			

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

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

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

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

(5) Reflects Oyster Creek retirement in September 2018 and TMI retirement by September 2019

(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⁾	196,300	201,900	192,900
Midwest	96,600	97,000	96,500
Mid-Atlantic ^(2,6)	60,300	54,000	48,500
ERCOT	16,900	25,500	23,700
New York ^(2,6)	16,200	16,600	15,600
New England	6,300	8,800	8,600
% of Expected Generation Hedged⁽³⁾	98%-101%	82%-85%	48%-51%
Midwest	98%-101%	79%-82%	44%-47%
Mid-Atlantic ^(2,6)	100%-103%	94%-97%	61%-64%
ERCOT	98%-101%	78%-81%	49%-52%
New York ^(2,6)	98%-101%	93%-96%	57%-60%
New England	78%-81%	23%-26%	13%-16%
Effective Realized Energy Price (\$/MWh)⁽⁴⁾			
Midwest	\$30.00	\$28.50	\$28.00
Mid-Atlantic ^(2,6)	\$39.00	\$37.50	\$37.00
ERCOT ⁽⁵⁾	(\$2.00)	\$2.00	\$1.00
New York ^(2,6)	\$36.00	\$32.00	\$30.00
New England ⁽⁵⁾	\$7.00	\$6.00	\$25.50

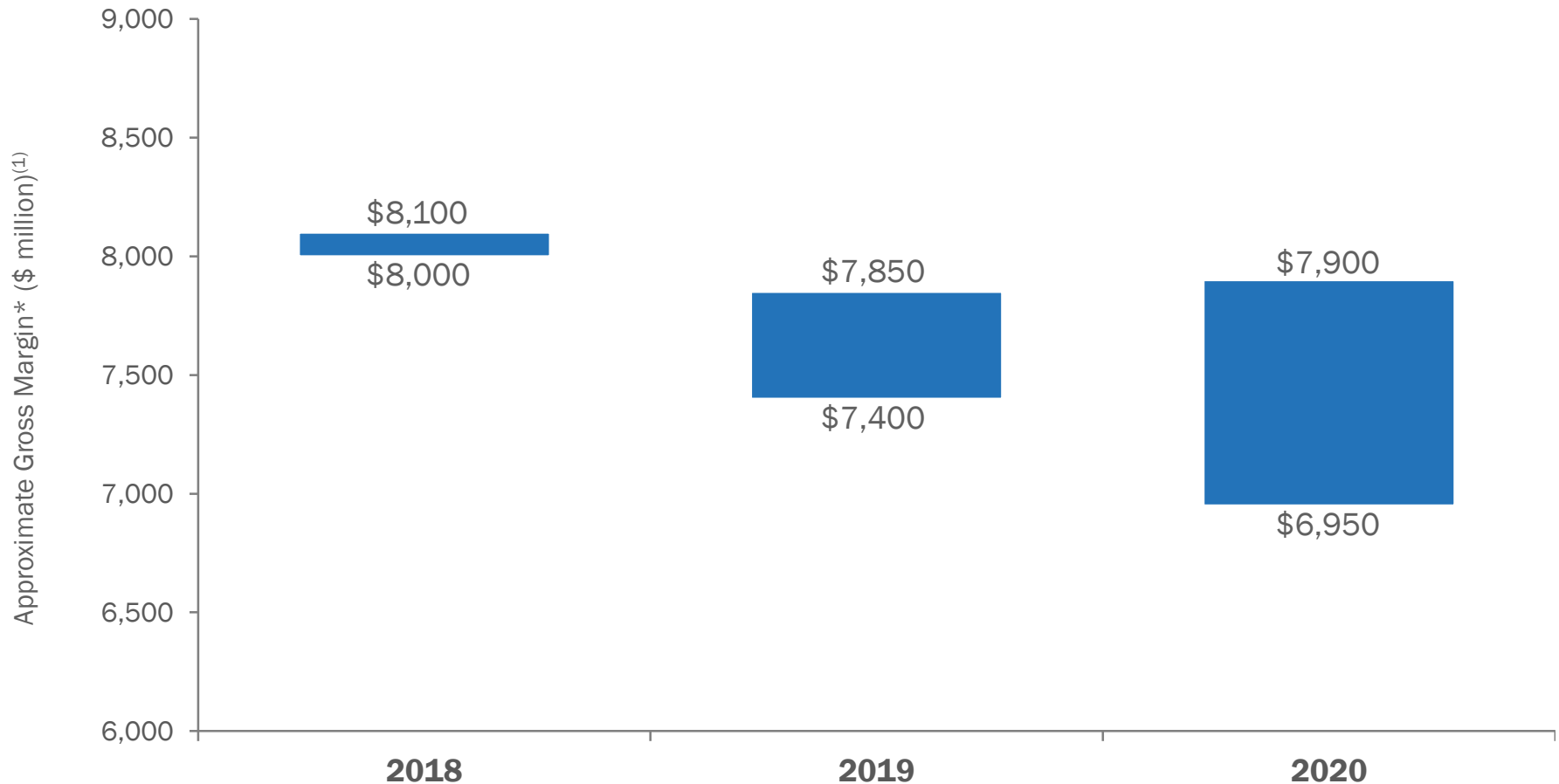
- (1) Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 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 94.3%, 94.6% 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 retirement in September 2018 and TMI retirement by September 2019

ExGen Hedged Gross Margin* Sensitivities

Gross Margin* Sensitivities (with existing hedges) ⁽¹⁾	2018	2019	2020
Henry Hub Natural Gas (\$/MMBtu)			
+ \$1/MMBtu	\$(10)	\$190	\$445
- \$1/MMBtu	\$20	\$(145)	\$(395)
NiHub ATC Energy Price			
+ \$5/MWh	-	\$100	\$265
- \$5/MWh	-	\$(100)	\$(265)
PJM-W ATC Energy Price			
+ \$5/MWh	\$(5)	\$20	\$95
- \$5/MWh	\$5	-	\$(90)
NYPP Zone A ATC Energy Price			
+ \$5/MWh	-	-	\$30
- \$5/MWh	-	\$(5)	\$(30)
Nuclear Capacity Factor			
+/- 1%	+/- \$10	+/- \$35	+/- \$30

(1) Based on September 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 September 30, 2018. Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions. Reflects Oyster Creek retirement in September 2018 and TMI retirement by September 2019

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	←—————→			\$4.3 billion	—————→	
(B)	Capacity and ZEC	←—————→			\$2.05 billion	—————→	
(C)	Expected Generation (TWh)	97.0	54.0	25.5	16.6	8.8	
(D)	Hedge % (assuming mid-point of range)	80.5%	95.5%	79.5%	94.5%	24.5%	
(E=C*D)	Hedged Volume (TWh)	78.1	51.6	20.3	15.7	2.2	
(F)	Effective Realized Energy Price (\$/MWh)	\$28.50	\$37.50	\$2.00	\$32.00	\$6.00	
(G)	Reference Price (\$/MWh)	\$26.24	\$33.53	\$11.50	\$29.49	\$6.88	
(H=F-G)	Difference (\$/MWh)	\$2.26	\$3.97	(\$9.50)	\$2.51	(\$0.88)	
(I=E*H)	Mark-to-Market value of hedges (\$ million) ⁽¹⁾	\$175	\$205	(\$195)	\$40	\$0	
(J=A+B+I)	Hedged Gross Margin (\$ million)				\$6,600		
(K)	Power New Business / To Go (\$ million)				\$550		
(L)	Non-Power Margins Executed (\$ million)				\$200		
(M)	Non-Power New Business / To Go (\$ million)				\$300		
(N=J+K+L+M)	Total Gross Margin*				\$7,650 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)}	\$8,525	\$8,125	\$7,800
Other Revenues ⁽⁴⁾	\$(200)	\$(175)	\$(200)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses	\$(275)	\$(300)	\$(250)
Total Gross Margin* (Non-GAAP)	\$8,050	\$7,650	\$7,350

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

Q3 QTD GAAP EPS Reconciliation

Three Months Ended September 30, 2017	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2017 GAAP Earnings Per Share⁽¹⁾	\$0.32	\$0.20	\$0.12	\$0.06	\$0.16	\$0.00	\$0.85
Mark-to-market impact of economic hedging activities	(0.05)	-	-	-	-	-	(0.05)
Unrealized gains related to NDT fund investments	(0.07)	-	-	-	-	-	(0.07)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	0.01	-	-	-	(0.01)	-	-
Long-lived asset impairments	0.03	-	-	-	-	-	0.03
Plant retirements and divestitures	0.08	-	-	-	-	-	0.08
Cost management program	0.01	-	-	-	-	-	0.01
Bargain purchase gain	(0.01)	-	-	-	-	-	(0.01)
Reassessment of deferred income taxes	0.02	-	-	-	-	(0.04)	(0.02)
Noncontrolling interests	0.02	-	-	-	-	-	0.02
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.36	\$0.19	\$0.12	\$0.07	\$0.15	(\$0.04)	\$0.85

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

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

Q3 QTD GAAP EPS Reconciliation (continued)

Three Months Ended September 30, 2018	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2018 GAAP Earnings (Loss) Per Share	\$0.24	\$0.20	\$0.13	\$0.06	\$0.19	(\$0.07)	\$0.76
Mark-to-market impact of economic hedging activities	(0.07)	-	-	-	-	0.01	(0.06)
Unrealized gains related to NDT fund investments	(0.06)	-	-	-	-	-	(0.06)
Long-lived asset impairments	0.01	-	-	-	-	-	0.01
Plant retirements and divestitures	0.21	-	-	-	-	-	0.21
Cost management program	0.01	-	-	-	-	-	0.01
Asset retirement obligation	-	-	-	-	0.02	-	0.02
Change in environmental liabilities	(0.01)	-	-	-	-	-	(0.01)
Reassessment of deferred income taxes	(0.03)	-	-	-	(0.01)	0.02	(0.02)
Noncontrolling interests	0.02	-	-	-	-	-	0.02
2018 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.33	\$0.20	\$0.13	\$0.07	\$0.20	(\$0.05)	\$0.88

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

Q3 YTD GAAP EPS Reconciliation

Nine Months Ended September 30, 2017	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2017 GAAP Earnings Per Share⁽¹⁾	\$0.52	\$0.47	\$0.35	\$0.24	\$0.38	\$0.06	\$2.02
Mark-to-market impact of economic hedging activities	0.10	-	-	-	-	-	0.10
Unrealized gains related to NDT fund investments	(0.22)	-	-	-	-	-	(0.22)
Amortization of commodity contract intangibles	0.03	-	-	-	-	-	0.03
Merger and integration costs	0.05	-	-	-	(0.01)	-	0.04
Merger commitments	(0.02)	-	-	-	(0.06)	(0.06)	(0.15)
Long-lived asset impairments	0.31	-	-	-	-	-	0.31
Plant retirements and divestitures	0.15	-	-	-	-	-	0.15
Cost management program	0.02	-	-	-	-	-	0.03
Bargain purchase gain	(0.25)	-	-	-	-	-	(0.25)
Like-kind exchange tax position	-	0.02	-	-	-	(0.05)	(0.03)
Reassessment of deferred income taxes	0.02	-	-	-	-	(0.06)	(0.04)
Tax settlements	(0.01)	-	-	-	-	-	(0.01)
Noncontrolling interests	0.08	-	-	-	-	-	0.08
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.77	\$0.50	\$0.35	\$0.25	\$0.31	(\$0.12)	\$2.06

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 recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018

Q3 YTD GAAP EPS Reconciliation (continued)

Nine Months Ended September 30, 2018	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2018 GAAP Earnings (Loss) Per Share	\$0.56	\$0.54	\$0.35	\$0.25	\$0.35	(\$0.13)	\$1.92
Mark-to-market impact of economic hedging activities	0.07	-	-	-	-	0.01	0.08
Unrealized losses related to NDT fund investments	0.10	-	-	-	-	-	0.10
Long-lived asset impairments	0.04	-	-	-	-	-	0.04
Plant retirements and divestitures	0.44	-	-	-	-	-	0.43
Cost management program	0.02	-	-	-	-	-	0.03
Asset retirement obligation	-	-	-	-	0.02	-	0.02
Reassessment of deferred income taxes	(0.03)	-	-	-	(0.01)	0.01	(0.03)
Noncontrolling interests	(0.04)	-	-	-	-	-	(0.04)
2018 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$1.16	\$0.54	\$0.35	\$0.25	\$0.36	(\$0.11)	\$2.55

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
 - Impairments of certain wind projects at Generation
 - Certain costs related to plant retirements
 - Costs incurred related to a cost management program
 - Non-cash impacts pursuant to the annual update of asset retirement obligations
 - Adjustment to the remeasurement of deferred income taxes as a result of the Tax Cuts and Jobs Act (TCJA) and changes in forecasted apportionment
 - 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

Q3 2018 Operating ROE Reconciliation (\$M)	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP)	\$77	\$103	\$191	\$1,407	\$1,778
Operating Exclusions	\$5	\$8	\$24	\$2	\$40
Adjusted Operating Earnings	\$82	\$111	\$215	\$1,409	\$1,817
Average Equity	\$1,065	\$1,434	\$2,590	\$13,808	\$18,898
Operating ROE (Adjusted Operating Earnings/Average Equity)	7.7%	7.7%	8.3%	10.2%	9.6%

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%

Note: Items may not sum due to rounding

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)	\$750	\$1,650	\$650	\$1,100	\$4,250	\$175	\$8,600
Other cash from investing activities	-	-	-	-	(\$275)	-	(\$275)
Counterparty collateral activity	-	-	-	-	(\$175)	-	(\$175)
Adjusted Cash Flow from Operations	\$750	\$1,650	\$650	\$1,100	\$3,800	\$175	\$8,150

2018 Cash From Financing Calculation (\$M) ⁽¹⁾	BGE	ComEd	PECO	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	\$275	\$550	\$0	\$375	(\$1,050)	(\$100)	\$50
Dividends paid on common stock	\$200	\$450	\$300	\$325	\$1,000	(\$950)	\$1,325
Financing Cash Flow	\$475	\$1,000	\$300	\$700	(\$50)	(\$1,050)	\$1,375

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⁾	\$275
Adjusted Ending Cash Balance ⁽³⁾	\$1,725
Adjustment for Cash Collateral Posted	(\$375)
GAAP Ending Cash Balance	\$1,350

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

(2) Represents the GAAP measure of net change in cash, which is the sum of cash flow from operations, cash from investing activities, and cash from financing activities. Figures reflect cash capital expenditures and CENG fleet at 100%.

(3) Adjusted Beginning and Ending cash balances reflect GAAP Beginning and End Cash Balances excluding counterparty collateral activity

GAAP to Non-GAAP Reconciliations

ExGen Adjusted O&M Reconciliation (\$M) ⁽¹⁾	2018	2019	2020	2021
GAAP O&M	\$5,475	\$4,925	\$4,825	\$4,750
Decommissioning ⁽²⁾	50	50	50	50
Oyster Creek Retirement ⁽⁵⁾	(100)	-	-	-
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses ⁽³⁾	(275)	(275)	(250)	(250)
O&M for managed plants that are partially owned	(400)	(400)	(425)	(425)
Other	(125)	(50)	(25)	-
Adjusted O&M (Non-GAAP)	\$4,625	\$4,250	\$4,175	\$4,125

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

(2) Reflects earnings neutral O&M

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

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

(5) 2018 Decommissioning costs include \$75M of asset retirement obligations for Oyster Creek retirement acceleration