Earnings Conference Call
1st Quarter 2018

May 2, 2018

Exelon®

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 First 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

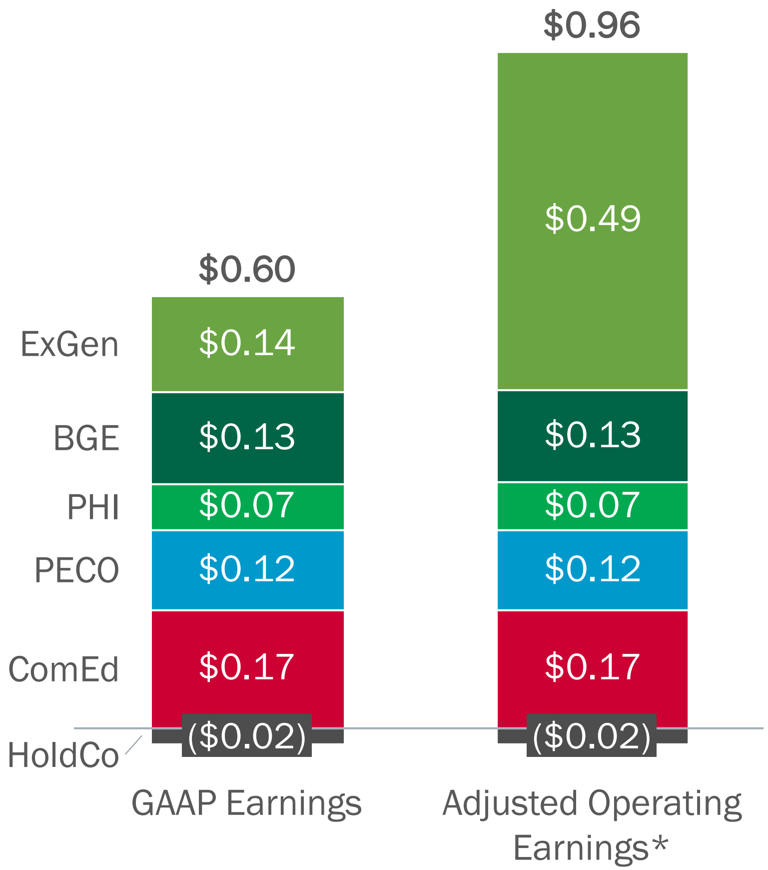
This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of Exelon's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business. 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 36 of this presentation.

1st Quarter Results

Q1 2018 EPS Results(1,2)



- GAAP earnings were $0.60/share in Q1 2018 vs. $1.06/share in Q1 2017
- Adjusted operating earnings* were $0.96/share in Q1 2018 vs. $0.64/share in Q1 2017, which is within our guidance range of $0.90-$1.00/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, Consolidated Statements of Cash Flows, Consolidated Balance Sheets and Consolidated Statements of Changes in Shareholders' Equity have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018

Operating Highlights

Exelon Utilities Operational Metrics

Operations	Metric	Q1 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 year to date was strong across the utilities, adjusted for normal storm events
- Customer operation metrics reflect solid performance across the utilities
- Safety performance year to date has been disappointing; safety improvement plans have been implemented to improve performance going forward

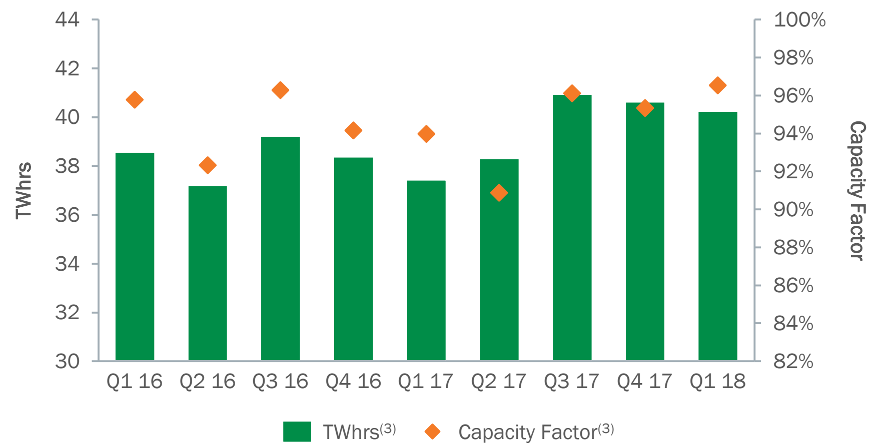
Q1	Q2
Q3	Q4

(1) 2.5 Beta SAIFI is YE projection
(2) Excludes Salem
(3) Excludes EDF's equity ownership share of the CENG Joint Venture

Exelon Generation Operational Performance

Exelon Nuclear Fleet

- Continued best in class performance across our Nuclear fleet:
  - Q1 Nuclear Capacity Factor: 96.5%(2)
  - Owned and operated Q1 production of 40 TWh(2)



Fossil and Renewable Fleet

- Strong performance across our Fossil and Renewable fleet:
  - Q1 Renewables energy capture: 95.2%
  - Q1 Power dispatch match: 98.1%

Exelon.

Our Scale Benefitted Customers Through Winter Storms

- **Three Nor'easters – Riley, Quinn and Toby – in March 2018 were the most damaging storms to hit the mid-Atlantic in the last six years**
  - Our East Cost utilities – ACE, BGE, DPL, Pepco and PECO – faced widespread outages due to the storms with a total of 1.7 million customers losing service at some point
  - Total operating and capital storm restoration expenditures of about $200 million
- **Exelon Utilities' scale and thoughtful pre-positioning expedited return to service for our customers**
  - ComEd dispatched 1,200 crews and contractors to our East Coast utilities to support storm response efforts
  - Common work protocols allowed for more efficient recovery efforts, speeding up service restoration for our customers

Exelon Utilities' scale allowed for quicker customer outage recovery during the recent winter storms

Tax Reform Yields Significant Customer Bill Savings

DPL

- MD PSC accepted DPL's proposal to provide **$14M** in annual tax savings to customers
  - $3.86 decrease on the average residential monthly bill
- DPL has filed plans with DE PSC to provide **$26M** in annual tax savings to customers
  - $2.99 and $4.77 decrease on the average residential monthly bill for Electric and Gas, respectively

ACE

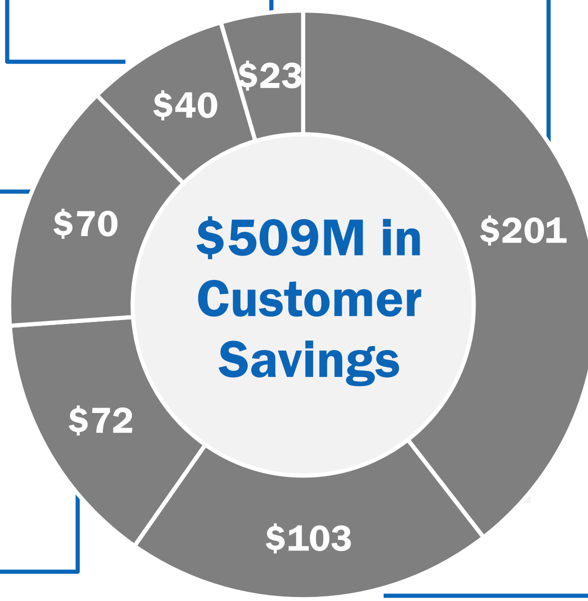
- ACE has filed a request with NJ BPU to provide **$23M** in annual tax savings to customers; expected to be approved by July
  - $2.37 savings on residential monthly bills

ComEd

- ICC approved ComEd's petition seeking approval to pass along approximately **$201M** in annual tax savings to customers
  - ~$3.00 decrease on the average residential monthly bill

Pepco

- Pepco has filed a request with the DC & MD PSC to provide **$70M** in annual tax savings to customers
- Pepco has filed settlements which include these savings as adjusted in its proposals to the commission



BGE

- MD PSC accepted BGE's proposal to provide approximately **$103M** in annual tax savings to customers
  - $2.91 decrease on the average residential monthly electric bill
  - $5.41 decrease on the average residential combined natural gas and electric bill

PECO

- Approximately **$72M** in annual tax savings to customers

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

Note: Currently includes only distribution-related customer savings amounts

ZEC & Policy Updates

New Jersey ZEC

- On April 12, 2018, the NJ ZEC bill passed both the Senate and Assembly with bipartisan support
- Bill is now before Governor Murphy, who has 45 days to sign
- Upon the Governor's signature, the BPU will begin the process of implementing the bill, including approving utility tariffs, developing a selection methodology, and reviewing applications for participation in the program
- Implementation of the program is scheduled to be completed around the end of Q1 2019

Illinois & New York ZEC Legal Challenges

Illinois:

- Oral arguments for the 7th Circuit occurred on January 3, 2018 – Judge requested supplemental briefings from parties
- Supplemental briefings were filed on January 26, 2018
- Court issued order on February 21, 2018, inviting the U.S. Government to provide its views
- Parties are awaiting response from the U.S. Solicitor General and further action by the court

New York:

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

PJM Price Formation

Fast Start:

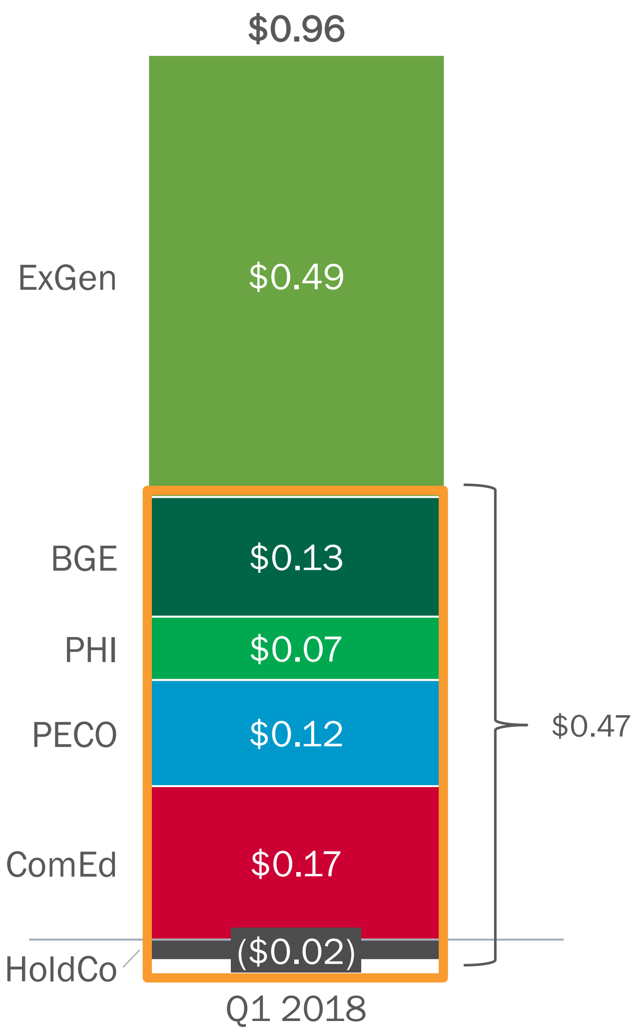
- Fast start NOPR was initiated by FERC (docket # EL18-34) and has now been fully briefed
- FERC has committed to providing a decision in September
  - If FERC approves by September, PJM believes it could implement the changes for the 2018/2019 winter

Baseload:

- PJM is in the midst of a stakeholder process scheduled to conclude in the 3rd quarter
- After completing the stakeholder process and receiving FERC's decision on the fast start docket, PJM will announce its process for moving forward

1st Quarter Adjusted Operating Earnings* Drivers

Q1 2018 Adjusted Operating EPS* Results



Q1 2018 vs. Guidance of $0.90 - $1.00

Exelon Utilities

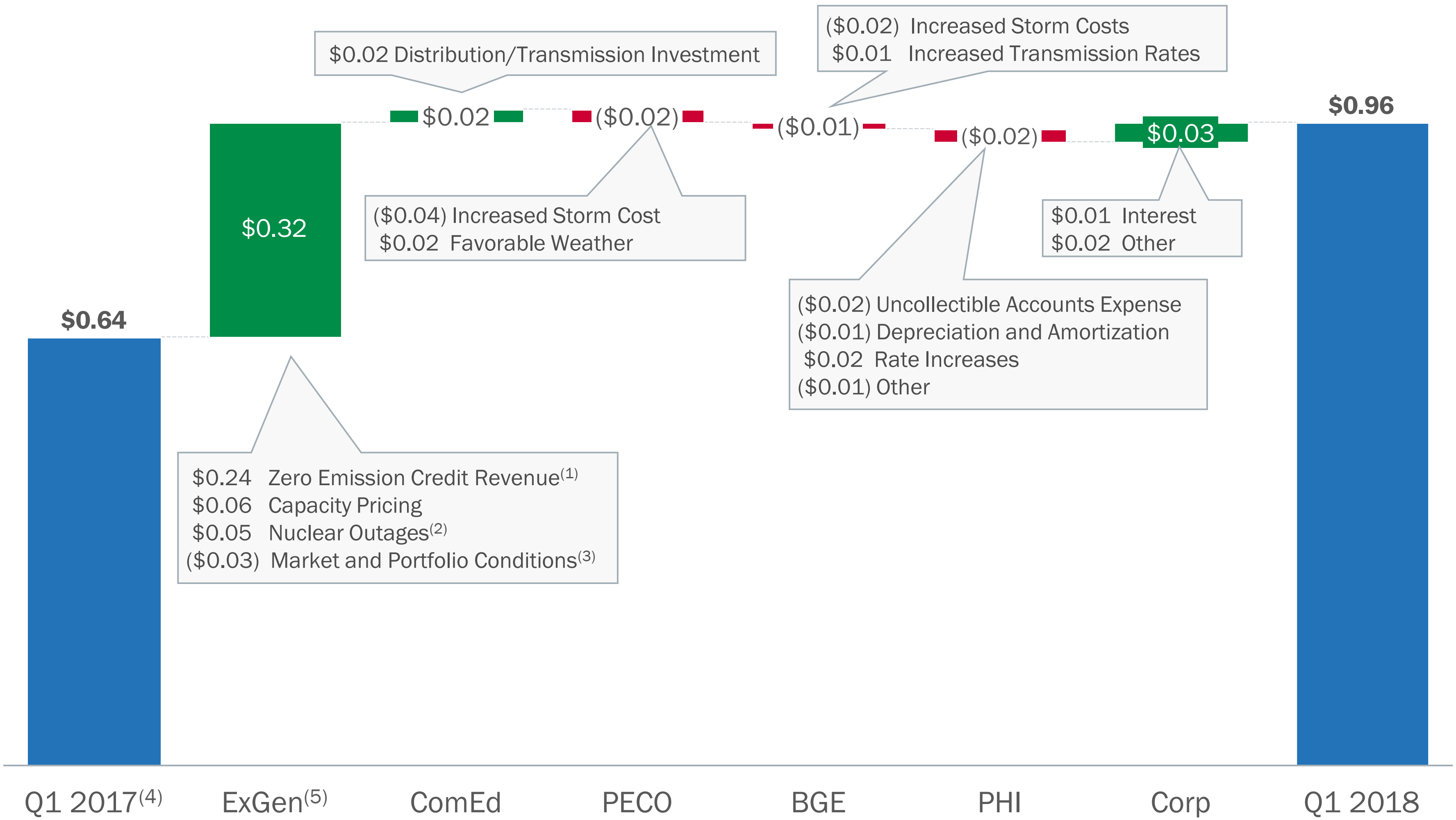
- ↓ Storm costs
- ↑ ComEd ROE

Exelon Generation

- ↑ Favorable O&M
- ↑ Generation performance

Note: Amounts may not sum due to rounding

QTD 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

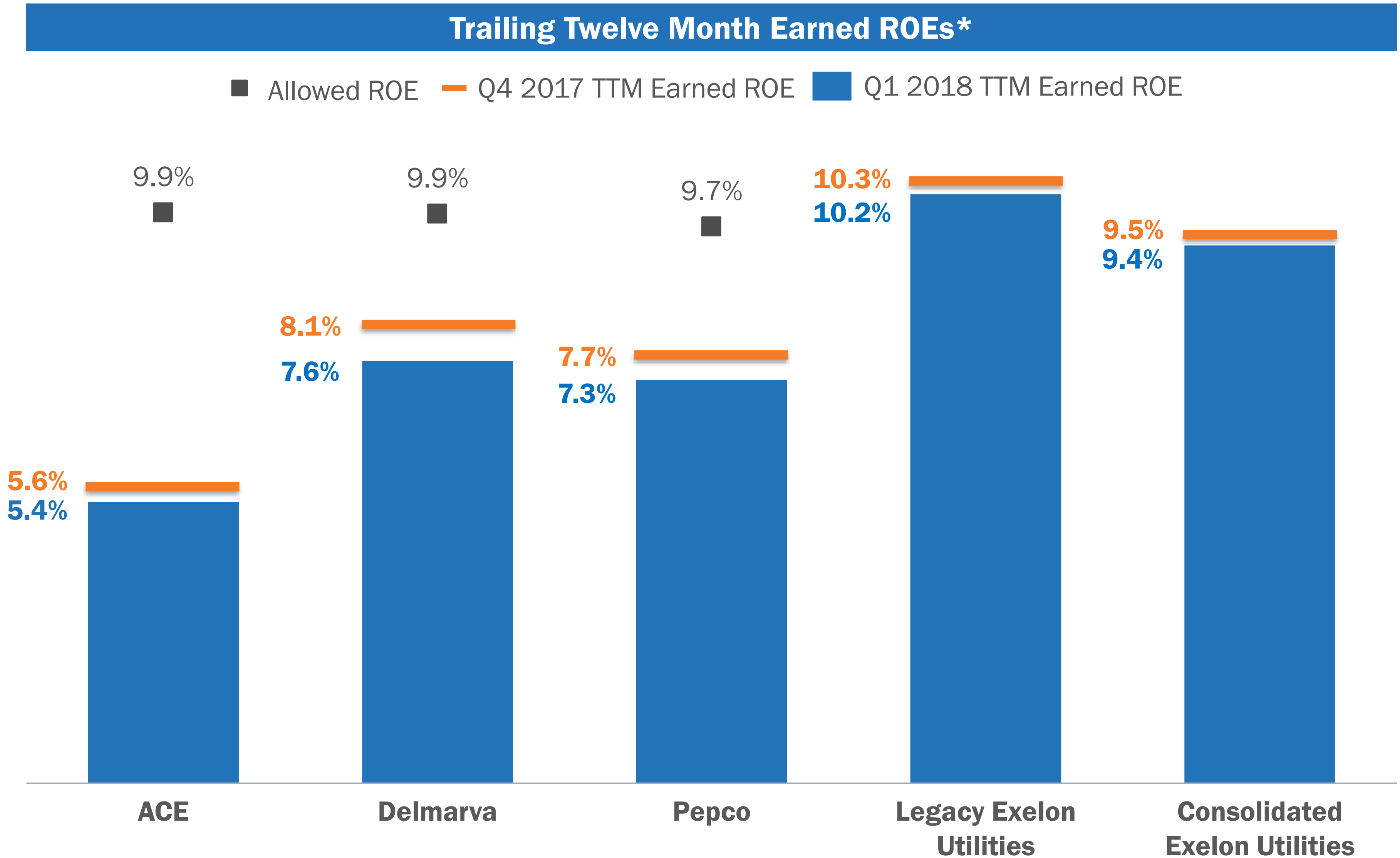
(2) Driven by lower nuclear outage days in 2018; excludes Salem

(3) Includes the unfavorable impact of the conclusion of the Ginna Reliability Support Services Agreement and lower realized energy prices, partially offset by the addition of two combined-cycle gas turbines in Texas

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

(5) Reflects CENG ownership at 100%

Trailing 12 Month ROEs* vs Allowed ROE



Note: Represents the 12-month periods ending 3/31/2017 and 3/31/2018, respectively. ROEs* represent weighted average across all lines of business (Electric Distribution, Gas Distribution and Transmission). Includes 20 bps and 10 bps impact to TTM earned ROEs from FAS 109 and winter storms, respectively.

Exelon Utilities' Distribution Rate Case Updates

Rate Case Schedule and Key Terms

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Revenue Requirement	Requested ROE / Equity Ratio	Expected Order
Delmarva (MD)		FO											Authorized: $13.4M	Authorized:[6] 9.50%/NA	Feb 9, 2018
ComEd[2]				CF		IT	RT	EH	IB RB			FO	$(22.9M)[1]	8.69% / 47.11%	Dec 2018
Delmarva Electric (DE)			IT		RT	EH	IB	RB	FO				$12.6M[1,3]	10.10% / 50.52%	Q3 2018
Delmarva Gas (DE)					IT		RT		EH	IB RB		FO	$3.9M[1,4]	10.10% / 50.52%	Q4 2018
Pepco Electric (DC)				SA	IT RT EH	IB	FO						$(24.1)M[1,7]	9.525% / 50.44%[7]	July 1, 2018[7]
Pepco Electric (MD)	CF			SA IT	EH	FO							$(15.0)M[1,7]	9.50% / 50.44%[7]	June 1, 2018[7]
PECO[2] Electric			CF			IT	RT	EH	IB RB			FO	$82M[1,5]	10.95% / 53%	Dec 2018

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, District of Columbia Public Service Commission, and Pennsylvania Public Utility Commission and are subject to change

(1) Revenue requirement includes changes in depreciation and amortization expense and other cots where applicable, which have no impact on pre-tax earnings
(2) Anticipated schedule; actual dates will be determined by ALJ at pre-hearing conference
(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. 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) Reflects $153M revenue requirement less an estimated $71M in 2019 tax benefit
(6) Solely for purposes of calculating the Allowance for Funds Used During Construction and regulatory asset carrying costs
(7) Per non-unanimous Settlement Agreement filed on April 17, 2018, for Pepco DC and April 20, 2018, for Pepco MD. Expected orders are based on requested rate effective dates. Includes tax benefits from Tax Cuts and Jobs Act.

Utility CapEx Update

DPL's Cedar Creek to Milford Transmission Rebuild

- Forecasted project cost:
  - $75 million
- In service date:
  - May 31, 2018
- Project scope:
  - Replace ~43 miles of 230 kV transmission poles as well as new conductor and optical ground wire
  - 230 kV line is a back-bone for the transmission network in the Delmarva region and one of the vital lines for north-south power flow within the Delmarva region
  - Improves reliability by eliminating the potential for outages due to structural failure of the line

ComEd's New Substation to Meet Data Center Growth

- Forecasted project cost:
  - $90 million
- In service date:
  - Q3 2021
- Project scope:
  - New green-field substation serving transmission and distribution loads; project to add over 300 MW of additional new capacity to the area
  - Supports transmission line reliability and projected data center growth in the Elk Grove Village area

Exelon Utilities remain committed to effectively deploying capital to the benefit of their customers

Exelon Generation: Gross Margin Update

Gross Margin Category ($M)[1]	March 31, 2018			Change from December 31, 2017		
	2018	2019	2020	2018	2019	2020
Open Gross Margin[2,5] (including South, West, Canada hedged gross margin)	$4,600	$3,950	$3,800	$250	$50	$50
Capacity and ZEC Revenues[2,5,6]	$2,300	$2,000	$1,850	-	-	-
Mark-to-Market of Hedges[2,3]	$300	$450	$250	$(50)	$50	-
Power New Business / To Go	$350	$650	$850	$(200)	$(100)	$(50)
Non-Power Margins Executed	$300	$150	$100	$100	$50	-
Non-Power New Business / To Go	$200	$350	$400	$(100)	$(50)	-
Total Gross Margin*[4,5]	**$8,050**	**$7,550**	**$7,250**	**-**	**-**	**-**

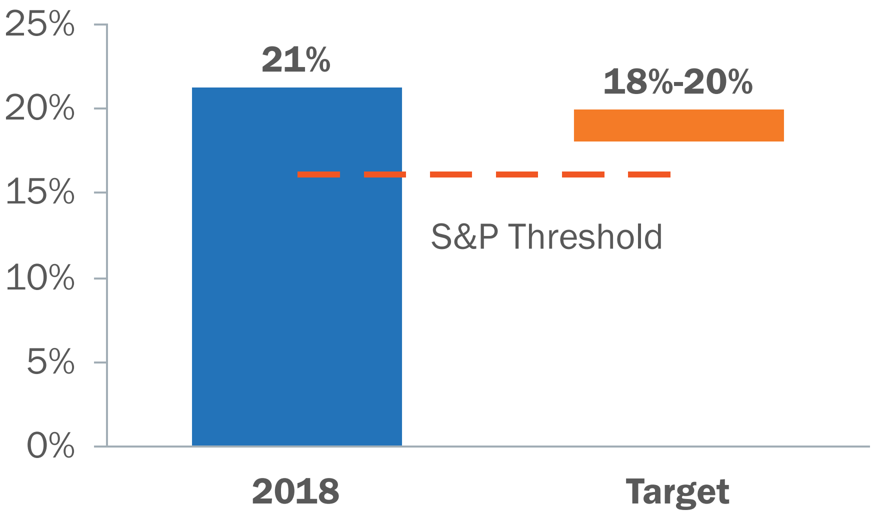
Recent Developments

- Open Gross Margin is up in all years due to strengthening ERCOT spark spreads, partly offset by lower NiHub prices
- Mark-to-Market of Hedges is down in all years due to higher prices, mostly offset by the execution of Power New Business
- Executed $200M and $100M of Power New Business in 2018 and 2019, respectively
- Behind ratable hedging position reflects the upside we see in power prices
  - ~8-11% behind ratable in 2019 when considering cross commodity hedges

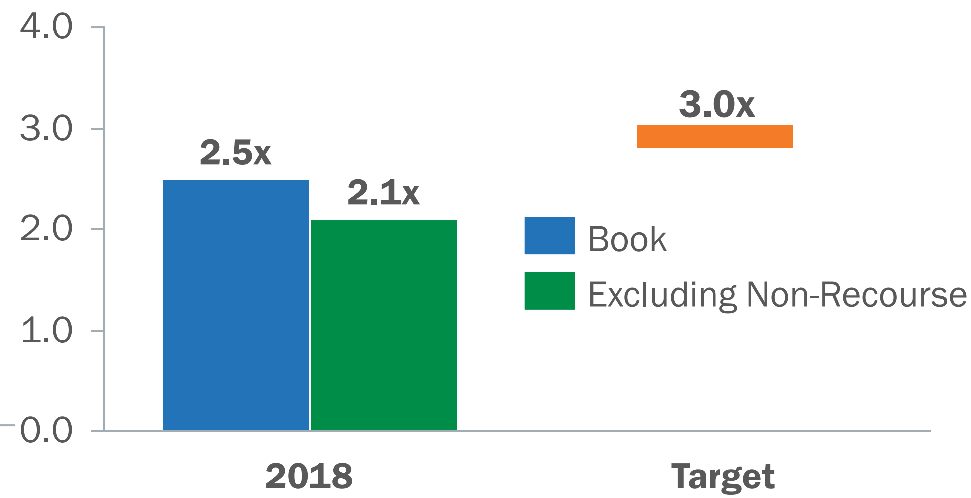
(1) Gross margin categories rounded to nearest $50M
(2) Excludes EDF's equity ownership share of the CENG Joint Venture
(3) Mark-to-Market of Hedges assumes mid-point of hedge percentages
(4) Based on March 31, 2018, market conditions
(5) Reflects Oyster Creek and TMI retirements by October 2018 and 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

Maintaining Strong Investment Grade Credit Ratings is a Top Financial Priority

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	A2	A2
S&P	BBB-	BBB	A-	A-	A-	A	A	A
Fitch	BBB	BBB	A	A	A-	A-	A	A-

(1) Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment
(2) Current senior unsecured ratings as of May 2, 2018, for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco
(3) All ratings have a "Stable" outlook, with the exception of ACE, which is on "Positive" outlook for Moody's
(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*

Exelon.

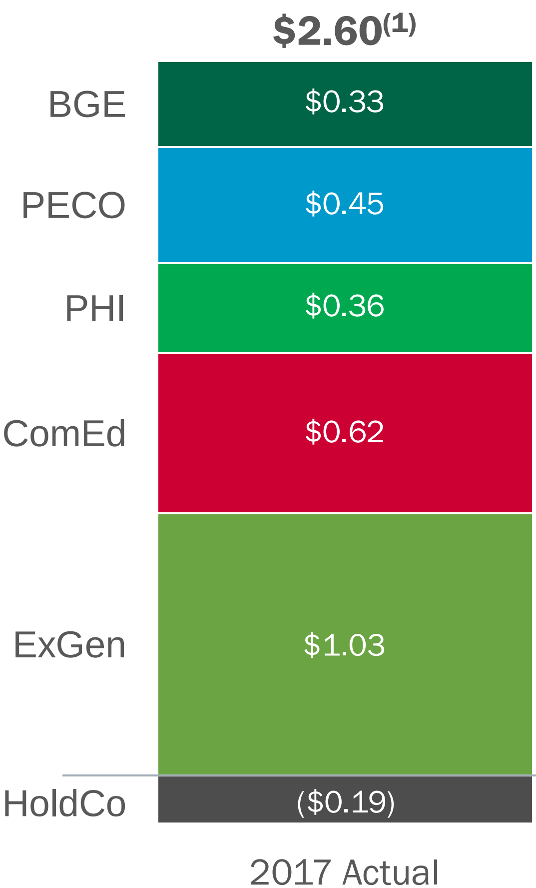
The Exelon Value Proposition

- **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

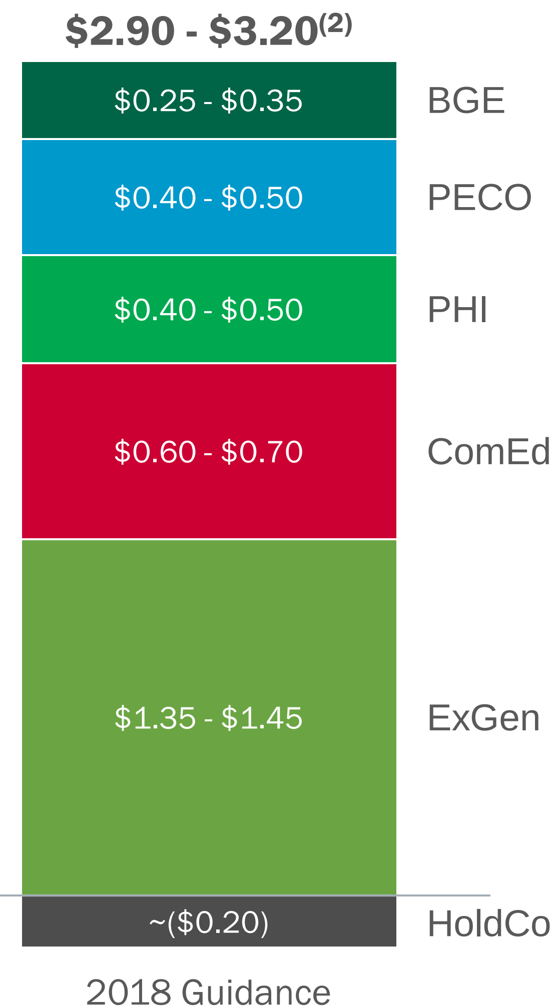
Additional Disclosures

2018 Adjusted Operating Earnings* Guidance



Key Year-Over-Year Drivers

- BGE: Return to normal storm (historical average) and inflation impacts
- PECO: Favorable weather, higher transmission revenue, offset by storm and higher depreciation
- PHI: Higher distribution and transmission revenue and absence of 2017 FAS 109 impact, partially offset by higher depreciation
- ComEd: Increased capital investments to improve reliability in distribution and transmission
- ExGen: Capacity and ZEC revenues (including recognition of 2017 IL ZEC), and tax reform, partially offset by market conditions



Expect Q2 2018 Adjusted Operating Earnings* of $0.55 - $0.65 per share

Note: Amounts may not add due to rounding
(1) 2017 results based on 2017 average outstanding shares of 949M
(2) 2018 earnings guidance based on expected average outstanding shares of 969M

Exelon.

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]	675	1,550	625	1,225	4,050	3,850	200	8,125	
Base CapEx and Nuclear Fuel[3]	0	0	0	0	0	(1,975)	(25)	(2,000)	
Free Cash Flow*	**675**	**1,550**	**625**	**1,225**	**4,050**	**1,900**	**150**	**6,125**	
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	100	450	50	325	925	0	(925)	0	
Other Financing[4]	150	375	25	(200)	375	(100)	100	375	
Financing*[5]	**550**	**1,300**	**275**	**600**	**2,725**	**(200)**	**(825)**	**1,700**	
Total Free Cash Flow and Financing	**1,225**	**2,825**	**900**	**1,825**	**6,775**	**1,700**	**(675)**	**7,825**	
Utility Investment	(1,000)	(2,125)	(850)	(1,525)	(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)**	**(1,525)**	**(5,525)**	**(400)**	**(1,325)**	**(7,250)**	
Total Cash Flow	**225**	**700**	**50**	**275**	**1,275**	**1,300**	**(2,000)**	**575**	
Ending Cash Balance*[2]									**2,025**

(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 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 and other intercompany financing activities
(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 $1.9B at ExGen and $4.1B 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

Exelon Utilities

ComEd Distribution Rate Case Filing

Rate Case Filing Details		Notes
Docket No.	18-0808	• 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(1)

	Jan – Dec
Filed rate case	4/16/2018
Intervenor testimony	6/2018
Rebuttal testimony	7/2018
Evidentiary hearings	8/2018
Initial Briefs Due	9/2018
Reply Briefs Due	9/2018
Commission Order Expected	12/2018

(1) Anticipated schedule, actual dates will be determined by ALJ at pre-hearing conference

Exelon.

Delmarva DE (Electric) Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	17-0977
Test Year	January 1, 2017 – December 31, 2017
Test Period	6 months actual and 6 months estimated
Requested Common Equity Ratio	50.52%
Requested Rate of Return	ROE: 10.10%; ROR: 6.98%
Proposed Rate Base (Adjusted)	$811M
Requested Revenue Requirement Increase	$12.6M[1,2]
Residential Total Bill % Increase	2.1%

Notes

- 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
- Forward looking reliability plant additions through August 2018 ($3.1M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request

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	3/29/2018
Rebuttal testimony	5/11/2018
Evidentiary hearings	6/26/2018 - 6/28/2018
Initial Briefs Due	7/23/2018
Reply Briefs Due	8/6/2018
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) Updated on February 9, 2018. Includes tax benefits from Tax Cuts and Jobs Act.

Delmarva DE (Gas) Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	17-0978
Test Year	January 1, 2017 – December 31, 2017
Test Period	6 months actual and 6 months estimated
Requested Common Equity Ratio	50.52%
Requested Rate of Return	ROE: 10.10%; ROR: 6.98%
Proposed Rate Base (Adjusted)	$347M
Requested Revenue Requirement Increase	$3.9M(1,2)
Residential Total Bill % Increase	4.0%

Notes

- 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 August 2018 ($1.0M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request

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 February 9, 2018. Includes tax benefits from Tax Cuts and Jobs Act.

Pepco DC (Electric) Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	1150 & 1151
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	$(24.1)M(1)
Residential Total Bill % decrease	(0.7)%(1)

Notes

- 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 $(24.1)M(1)
- Settling Parties have proposed a procedural schedule that would place rates in effect by July 1, 2018(1)

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							
Evidentiary hearings						5/31/2018							
Briefs due							6/14/2018						
Commission order expected								7/1/2018					

(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.

Exelon

Pepco MD (Electric) Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	9472
Test Year	January 1, 2017 – December 31, 2017
Test Period	12 months actual update
Requested Common Equity Ratio	50.44%
Requested Rate of Return	ROE: 9.50%; ROR: 7.44%[1]
Proposed Rate Base (Adjusted)	N/A[1]
Requested Revenue Requirement Increase	$(15.0)M[1]
Residential Total Bill % Increase	(1.3)%[1]

Notes

- 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 $(15.0)M[1]
- Settling Parties have proposed a procedural schedule that would place rates in effect by June 1, 2018[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 expected							6/1/2018						

(1) Per non-unanimous Settlement Agreement filed on April 20, 2018. Includes tax benefits from Tax Cuts and Jobs Act. Expected order is based on requested rate effective date.

PECO Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	R-2018-3000164
Test Year	January 1, 2019 – December 31, 2019
Test Period	12 Months Budget
Requested Common Equity Ratio	53%
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%

Notes

- PECO filed an electric distribution base rate case on March 29, 2018
- Since January 1, 2016, through the Fully Projected Future Test Year (2019):
  - 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

Detailed Rate Case Schedule(2)

	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						6/2018						
Rebuttal testimony							7/2018					
Evidentiary hearings								8/2018				
Initial Briefs Due									9/2018			
Reply Briefs Due									9/2018			
Commission Order Expected												12/2018

(1) Reflects $153M revenue requirement less an estimated $71M in 2019 tax benefit
(2) Anticipated schedule, actual dates will be determined by ALJ at pre-hearing conference

Exelon Generation Disclosures

March 31, 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

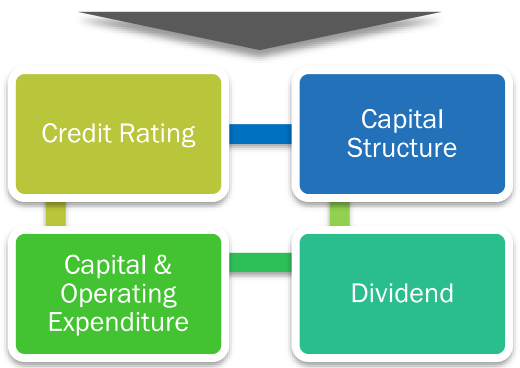
- Ensure stability in near-term cash flows and earnings
  - Disciplined approach to hedging
  - Tenor aligns with customer preferences and market liquidity
  - Multiple channels to market that allow us to maximize margins
  - Large open position in outer years to benefit from price upside

Bull / Bear Program

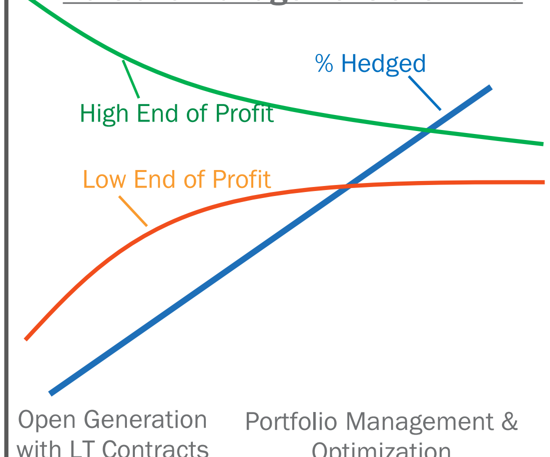
- Ability to exercise fundamental market views to create value within the ratable framework
  - Modified timing of hedges versus purely ratable
  - Cross-commodity hedging (heat rate positions, options, etc.)
  - Delivery locations, regional and zonal spread relationships

Align Hedging & Financials

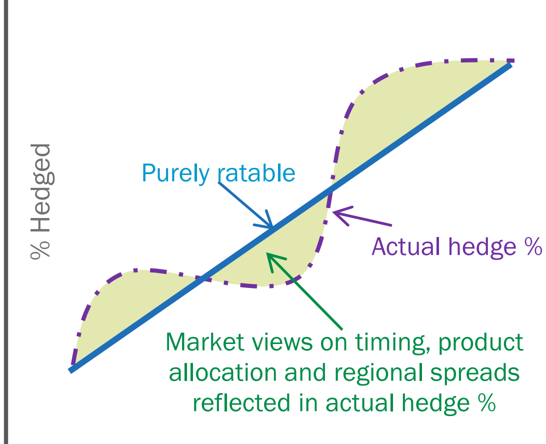
Establishing Minimum Hedge Targets



Portfolio Management Over Time



Exercising Market Views



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

Exelon.

Components of Gross Margin Categories

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

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

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

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

ExGen Disclosures

Gross Margin Category ($M)[1]	2018	2019	2020
Open Gross Margin (including South, West & Canada hedged GM)[2,5]	$4,600	$3,950	$3,800
Capacity and ZEC Revenues[2,5,6]	$2,300	$2,000	$1,850
Mark-to-Market of Hedges[2,3]	$300	$450	$250
Power New Business / To Go	$350	$650	$850
Non-Power Margins Executed	$300	$150	$100
Non-Power New Business / To Go	$200	$350	$400
Total Gross Margin*[4,5]	**$8,050**	**$7,550**	**$7,250**

Reference Prices[4]	2018	2019	2020
Henry Hub Natural Gas ($/MMBtu)	$2.87	$2.79	$2.78
Midwest: NiHub ATC prices ($/MWh)	$26.48	$26.12	$26.21
Mid-Atlantic: PJM-W ATC prices ($/MWh)	$34.11	$30.85	$30.52
ERCOT-N ATC Spark Spread ($/MWh) *HSC Gas, 7.2HR, $2.50 VOM*	$13.67	$9.85	$8.08
New York: NY Zone A ($/MWh)	$28.22	$26.00	$26.16
New England: Mass Hub ATC Spark Spread ($/MWh) *ALQN Gas, 7.5HR, $0.50 VOM*	$4.86	$5.06	$5.11

(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 March 31, 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

ExGen Disclosures

Generation and Hedges	2018	2019	2020
Exp. Gen (GWh)[1]	**202,200**	**203,300**	**192,800**
Midwest	96,500	97,200	96,700
Mid-Atlantic[2,6]	59,600	54,300	48,700
ERCOT	24,000	26,400	23,200
New York[2,6]	15,700	16,600	15,500
New England	6,400	8,800	8,700
% of Expected Generation Hedged[3]	**91%-94%**	**63%-66%**	**33%-36%**
Midwest	89%-92%	58%-61%	28%-31%
Mid-Atlantic[2,6]	98%-101%	74%-77%	41%-44%
ERCOT	81%-84%	61%-64%	34%-37%
New York[2,6]	99%-102%	73%-76%	39%-42%
New England	81%-84%	32%-35%	39%-42%
Effective Realized Energy Price ($/MWh)[4]			
Midwest	$29.00	$29.00	$30.00
Mid-Atlantic[2,6]	$38.00	$38.50	$39.50
ERCOT[5]	$0.00	$2.00	$1.00
New York[2,6]	$35.50	$31.50	$29.00
New England[5]	$5.50	$4.00	$10.00

(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 93.9%, 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

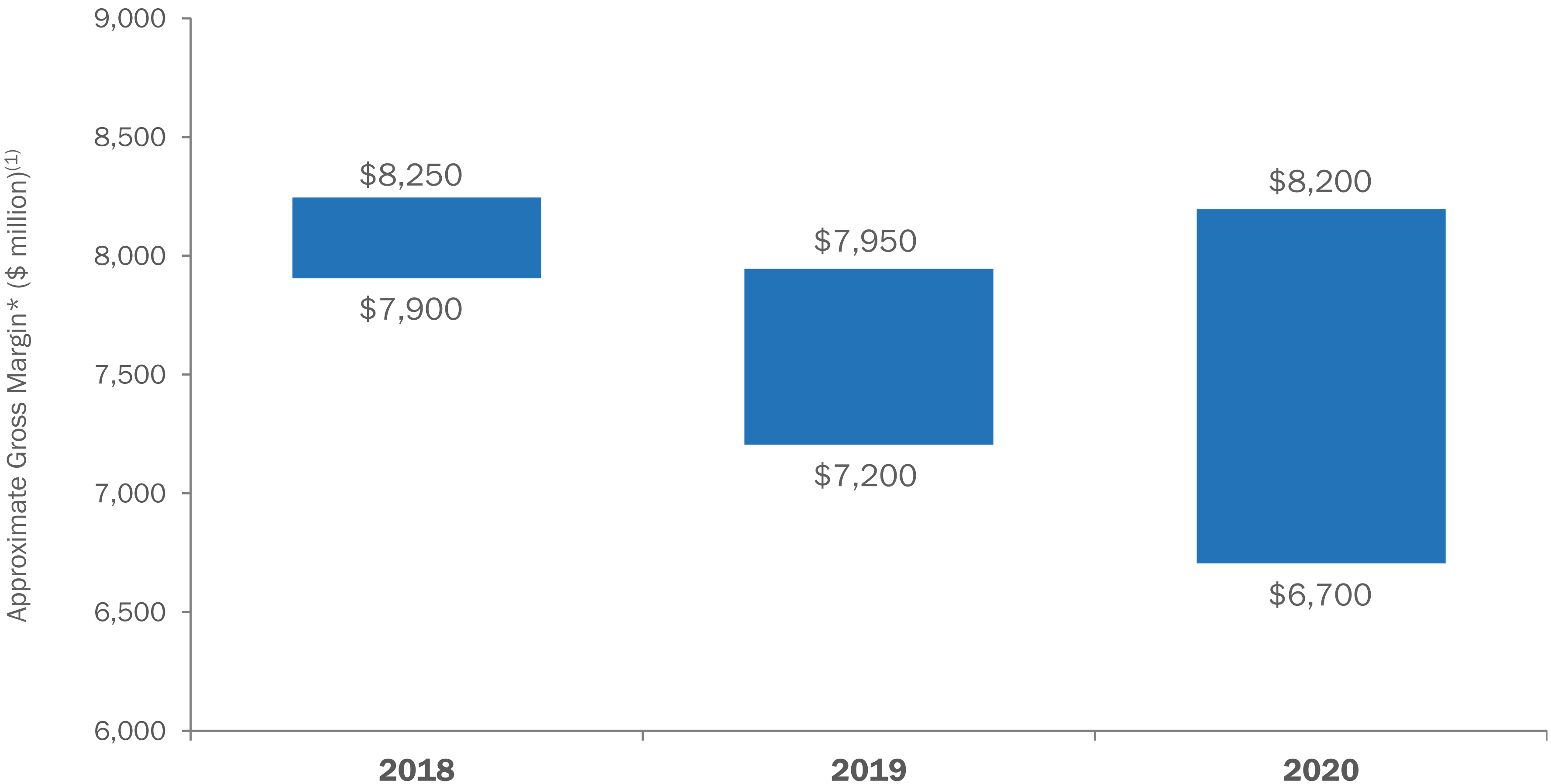
(6) Reflects Oyster Creek and TMI retirements by October 2018 and September 2019, respectively. 2018, 2019 and 2020 are adjusted for retaining Handley Generating Station.

ExGen Hedged Gross Margin* Sensitivities

Gross Margin* Sensitivities (with existing hedges)[1]	2018	2019	2020
Henry Hub Natural Gas ($/MMBtu)			
+ $1/MMBtu	$95	$385	$635
- $1/MMBtu	$(70)	$(360)	$(595)
NiHub ATC Energy Price			
+ $5/MWh	$40	$190	$330
- $5/MWh	$(40)	$(185)	$(330)
PJM-W ATC Energy Price			
+ $5/MWh	-	$65	$150
- $5/MWh	$10	$(55)	$(140)
NYPP Zone A ATC Energy Price			
+ $5/MWh	-	$20	$45
- $5/MWh	-	$(20)	$(45)
Nuclear Capacity Factor			
+/- 1%	+/- $30	+/- $35	+/- $35

(1) Based on March 31, 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 March 31, 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 Gross Margin*

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	←		$3.95 billion			→
(B)	Capacity and ZEC	←		$2 billion			→
(C)	Expected Generation (TWh)	97.2	54.3	26.4	16.6	8.8	
(D)	Hedge % (assuming mid-point of range)	59.5%	75.5%	62.5%	74.5%	33.5%	
(E=C*D)	Hedged Volume (TWh)	57.8	41.0	16.5	12.4	2.9	
(F)	Effective Realized Energy Price ($/MWh)	$29.00	$38.50	$2.00	$31.50	$4.00	
(G)	Reference Price ($/MWh)	$26.12	$30.85	$9.85	$26.00	$5.06	
(H=F-G)	Difference ($/MWh)	$2.88	$7.65	($7.85)	$5.50	($1.06)	
(I=E*H)	Mark-to-Market value of hedges ($ million)[1]	$165	$315	($130)	$70	($5)	
(J=A+B+I)	Hedged Gross Margin ($ million)			$6,400			
(K)	Power New Business / To Go ($ million)			$650			
(L)	Non-Power Margins Executed ($ million)			$150			
(M)	Non-Power New Business / To Go ($ million)			$350			
(N=J+K+L+M)	**Total Gross Margin***			**$7,550 million**			

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

Exelon.

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**	**$8,025**	**$7,700**
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**	**$7,550**	**$7,250**

Key ExGen Modeling Inputs (in $M)[1,5]	2018
Other[6]	$150
Adjusted O&M*	$(4,550)
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
(7) TOTI excludes gross receipts tax of $125M
(8) 2019 Depreciation & Amortization is flat to 2018 and 2020 is favorable $50M due to nuclear plant retirements

Exelon.

Appendix

Reconciliation of Non-GAAP Measures

Q1 QTD GAAP EPS Reconciliation

Three Months Ended March 31, 2017	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2017 GAAP Earnings Per Share[1]	**$0.45**	**$0.15**	**$0.14**	**$0.13**	**$0.15**	**$0.04**	**$1.06**
Mark-to-market impact of economic hedging activities	0.03	-	-	-	-	-	0.03
Unrealized gains related to NDT fund investments	(0.10)	-	-	-	-	-	(0.10)
Merger and integration costs	0.02	-	-	0.01	-	-	0.03
Merger commitments	(0.02)	-	-	-	(0.06)	(0.07)	(0.15)
Reassessment of state deferred income taxes	-	-	-	-	-	(0.02)	(0.02)
Tax settlements	(0.01)	-	-	-	-	-	(0.01)
Bargain purchase gain	(0.24)	-	-	-	-	-	(0.24)
CENG non-controlling interest	0.04	-	-	-	-	-	0.04
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.17**	**$0.15**	**$0.14**	**$0.14**	**$0.09**	**($0.05)**	**0.64**

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, Consolidated Statements of Cash Flows, Consolidated Balance Sheets and Consolidated Statements of Changes in Shareholders' Equity have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018

Q1 QTD GAAP EPS Reconciliation (continued)

Three Months Ended March 31, 2018	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2018 GAAP Earnings (Loss) Per Share	**$0.14**	**$0.17**	**$0.12**	**$0.13**	**$0.07**	**($0.02)**	**$0.60**
Mark-to-market impact of economic hedging activities	0.20	-	-	-	-	-	0.20
Unrealized losses related to NDT fund investments	0.07	-	-	-	-	-	0.07
Cost management program	-	-	-	-	-	-	0.01
Plant retirements and divestitures	0.10	-	-	-	-	-	0.10
Noncontrolling interests	(0.02)	-	-	-	-	-	(0.02)
2018 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.49**	**$0.17**	**$0.12**	**$0.13**	**$0.07**	**($0.02)**	**$0.96**

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

Exelon.

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 to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements
  - Certain merger and integration costs
  - 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

Exelon.

GAAP to Non-GAAP Reconciliations

YE 2018 Exelon FFO Calculation ($M)[1,2]	
GAAP Operating Income	$3,525
Depreciation & Amortization	$3,850
EBITDA	$7,375
+/- Non-operating activities and nonrecurring items[3]	$275
- Interest Expense	($1,400)
+ Current Income Tax (Expense)/Benefit	$50
+ Nuclear Fuel Amortization	$1,075
+/- Other S&P Adjustments[4]	$275
= FFO (a)	**$7,650**

YE 2018 Exelon Adjusted Debt Calculation ($M)[1,2]	
Long-Term Debt (including current maturities)	$33,000
Short-Term Debt	$1,175
+ PPA and Operating Lease Imputed Debt[5]	$1,025
+ Pension/OPEB Imputed Debt[6]	$4,000
- Off-Credit Treatment of Debt[7]	($1,875)
- Surplus Cash Adjustment[8]	($1,125)
+/- Other S&P Adjustments[4]	($525)
= Adjusted Debt (b)	**$35,675**

YE 2018 Exelon FFO/Debt[1,2]		
FFO (a) / Adjusted Debt (b)	=	21%

(1) All amounts rounded to the nearest $25M and may not add due to rounding
(2) Calculated using S&P Methodology. Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment.
(3) Reflects impact of operating adjustments on GAAP EBITDA
(4) Reflects other adjustments as prescribed by S&P
(5) Reflects present value of net capacity purchases and present value of minimum future operating lease payments
(6) Reflects after-tax underfunded pension/OPEB
(7) Reflects adjustment for non-recourse project debt per S&P guidelines
(8) Reflects 75% of excess cash applied against balance of LTD

GAAP to Non-GAAP Reconciliations

YE 2018 ExGen Net Debt Calculation ($M)[1,2]	
Long-Term Debt (including current maturities)	$8,850
Short-Term Debt	$0
- Surplus Cash Adjustment	($900)
= Net Debt (a)	**$7,950**

YE 2018 ExGen Net Debt Calculation ($M)[1,2]	
Long-Term Debt (including current maturities)	$8,850
Short-Term Debt	$0
- Surplus Cash Adjustment	($900)
- Nonrecourse Debt	($2,075)
= Net Debt (a)	**$5,875**

YE 2018 ExGen Operating EBITDA Calculation ($M)[1]	
GAAP Operating Income[3]	$1,025
Depreciation & Amortization[3]	$1,725
EBITDA[3]	$2,750
+/- Non-operating activities and nonrecurring items[2]	$375
= Operating EBITDA (b)	**$3,125**

YE 2018 ExGen Operating EBITDA Calculation ($M)[1]	
GAAP Operating Income[3]	$1,025
Depreciation & Amortization[3]	$1,725
EBITDA[3]	$2,750
+/- Non-operating activities and nonrecurring items[2]	$375
- EBITDA from projects financed by nonrecourse debt	($275)
= Operating EBITDA (b)	**$2,850**

YE 2018 Book Debt / EBITDA

$$\frac{\text{Net Debt (a)}}{\text{Operating EBITDA (b)}} = 2.5x$$

YE 2018 Recourse Debt / EBITDA

$$\frac{\text{Net Debt (a)}}{\text{Operating EBITDA (b)}} = 2.1x$$

(1) All amounts rounded to the nearest $25M
(2) Reflects impact of operating adjustments on GAAP EBITDA
(3) Reflects Exelon nuclear plants at ownership

GAAP to Non-GAAP Reconciliations

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%**

Q4 2017 Operating ROE Reconciliation ($M)	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP)	$77	$121	$205	$1,308	$1,711
Operating Exclusions	($20)	($13)	($20)	$28	($24)
Adjusted Operating Earnings	$58	$108	$185	$1,336	$1,687
Average Equity	$1,038	$1,330	$2,417	$13,003	$17,787
Operating ROE (Adjusted Operating Earnings/Average Equity)	**5.6%**	**8.1%**	**7.7%**	**10.3%**	**9.5%**

ExGen Adjusted O&M Reconciliation ($M)[1]	2018
GAAP O&M	**$5,225**
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	(50)
Adjusted O&M (Non-GAAP)	**$4,550**

(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*

Exelon.

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)	$675	$1,550	$625	$1,225	$4,075	$200	$8,325
Other cash from investing activities	-	-	-	-	($275)	-	($275)
Counterparty collateral activity	-	-	-	-	75	-	75
Adjusted Cash Flow from Operations	**$675**	**$1,550**	**$625**	**$1,225**	**$3,850**	**$200**	**$8,125**

2018 Cash From Financing Calculation ($M)(1)	BGE	ComEd	PECO	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	$350	$850	($25)	$300	($950)	($150)	$375
Dividends paid on common stock	$200	$450	$300	$300	$750	($675)	$1,325
Financing Cash Flow	**$550**	**$1,300**	**$275**	**$600**	**($200)**	**($825)**	**$1,700**

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)	$575
Adjusted Ending Cash Balance(3)	$2,025
Adjustment for Cash Collateral Posted	($600)
GAAP Ending Cash Balance	**$1,425**

(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

Exelon.