

Earnings Conference Call 2nd Quarter 2017

August 2, 2017



Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2016 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 24, Commitments and Contingencies; (2) Exelon's Second Quarter 2017 Quarterly Report on Form 10-Q (to be filed on August 2, 2017) in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 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, and other items as set forth in the reconciliation in the Appendix
- **Total gross margin** is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, JExel Nuclear JV, variable interest entities, and net of direct cost of sales for certain Constellation and Power businesses
- **Adjusted cash flow from operations** primarily includes net cash flows from operating activities and net cash flows from investing activities excluding capital expenditures, net merger and acquisitions, and equity investments
- **Free cash flow** primarily includes net cash flows from operating activities and net cash flows from investing activities excluding certain capital expenditures, net merger and acquisitions, and equity investments
- **Operating ROE** is calculated using operating net income divided by average equity for the period. The operating income reflects all lines of business for the utility business (Electric Distribution, Gas Distribution, Transmission).
- **EBITDA** is defined as earnings before interest, taxes, depreciation and amortization. Includes nuclear fuel amortization expense.
- **Revenue net of purchased power and fuel expense** is calculated as the GAAP measure of operating revenue less the GAAP measure of purchased power and fuel expense

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

Non-GAAP Financial Measures Continued

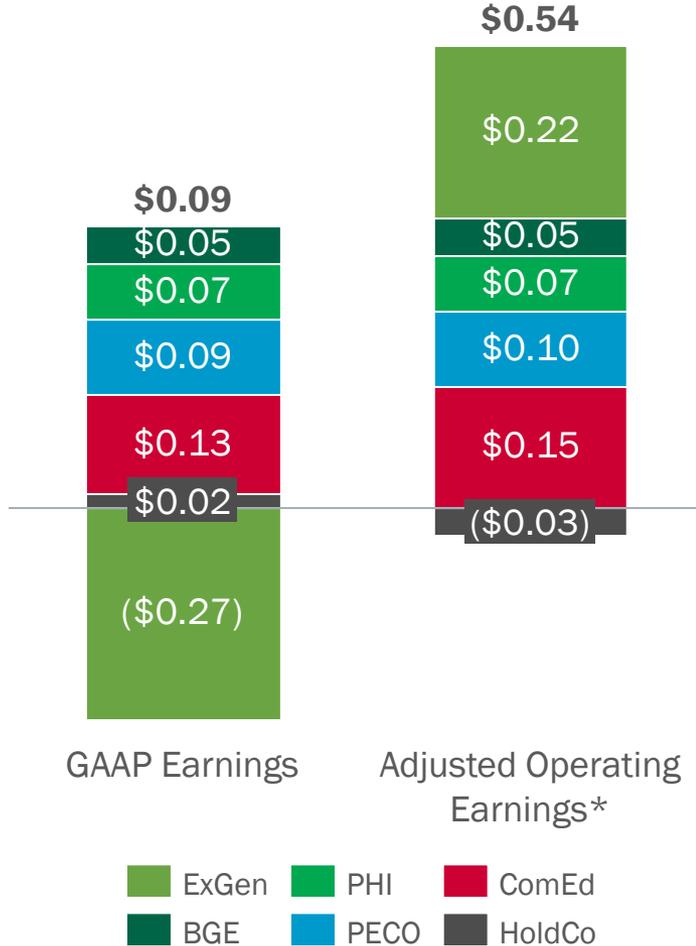
This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of Exelon's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business.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

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

Non-GAAP financial measures are identified by the phrase "non-GAAP" or an asterisk. Reconciliations of these non-GAAP measures to the most comparable GAAP measures are provided in the appendices and attachments to this presentation, except for the reconciliation for total gross margin, which appears on slide 33 of this presentation.

Strong 2nd Quarter Results

Q2 2017 EPS Results



- GAAP earnings were \$0.09/share in Q2 2017 vs. \$0.29/share in Q2 2016
- Adjusted operating earnings* were \$0.54/share in Q2 2017 vs. \$0.65/share in Q2 2016, near the top end of our guidance range of \$0.45-\$0.55/share

Note: Amounts may not sum due to rounding

* Refer to pages 3 and 4 for information regarding non-GAAP financial measures

Operating Highlights

Exelon Utilities Operational Metrics					
Operations	Metric	Q2 2017			
		BGE	ComEd	PECO	PHI
Electric Operations	OSHA Recordable Rate	Yellow	Green	Green	Green
	2.5 Beta SAIFI (Outage Frequency) ⁽¹⁾	Green	Green	Green	Orange
	2.5 Beta CAIDI (Outage Duration)	Green	Green	Green	Green
Customer Operations	Customer Satisfaction	Green	Green	Green	Yellow
	Service Level % of Calls Answered in <30 sec	Yellow	Green	Yellow	Green
	Abandon Rate	Green	Green	Green	Green
Gas Operations	Percent of Calls Responded to in <1 Hour	Green	No Gas Operations	Green	Green

- BGE and ComEd are meeting 1st decile performance in CAIDI
- BGE’s CAIDI and SAIFI performance was best on record
- ComEd’s SAIFI performance was best on record
- Pepco identified in JD Power customer satisfaction study as one of the most improved utilities for 2017 vs 2016

(1) 2.5 Beta SAIFI is YE projection
 (2) Excludes Salem
 (3) 2016 industry average

Q1	Q2
Q3	Q4

Exelon Generation Operational Metrics

- Continued best in class performance across our Nuclear fleet:
 - Q2 Nuclear Capacity Factor: 90.9%⁽²⁾
 - Q2 average refueling outage duration of 24 days versus industry average of 36 days⁽³⁾
 - Shortest refueling outage duration record set for Nine Mile Point 1
- Strong performance across our Fossil and Renewable fleet:
 - Q2 Renewables energy capture: 95.5%
 - Q2 Power dispatch match: 99.0%

Key Developments from the Second Quarter

ZEC Litigation Updates

PHI Rate Case Progress

PJM Capacity Auction

TMI Shutdown Decision

Key Market Policy Updates

New York ZEC Legal Challenges

Federal Case:

- Case dismissed on July 25 and judgment entered on July 27
- “The ZEC program does not thwart the goal of an efficient energy market; rather, it encourages through financial incentives the production of clean energy.”
- The plaintiffs are expected to appeal to the US Court of Appeals for the 2nd Circuit
- The 2nd Circuit will set the briefing schedule after the appeal is filed

State Case:

- Motions to dismiss procedural challenges filed in NY State court were briefed in 1Q17
- The court heard oral arguments on June 19, 2017
- Currently awaiting decision; next step determined by outcome

IL ZEC Legal Challenges

- Both cases dismissed and judgment entered July 14
- “The ZEC program does not conflict with the Federal Power Act.”
- On July 17, both sets of plaintiffs appealed to the US Court of Appeals for the 7th Circuit
- On July 18, the 7th Circuit consolidated the appeals and set a briefing schedule:
 - Plaintiff-Appellant Opening Brief due Aug 28
 - Defendant-Respondents Response Brief due Sep 27
 - Reply Briefs due Oct 27
 - Expect oral argument to follow

DOE Report and PJM Reforms

DOE Energy Report

- On April 14, 2017, Secretary of Energy Rick Perry ordered a review of the U.S. electrical grid, to determine if current policies are hastening the retirement of baseload plants and threatening power system resilience and reliability.

- “Nuclear power is a key component of our all-of-the-above energy strategy. Zero emissions, always on.” – Secretary Rick Perry

Proposed PJM Reforms

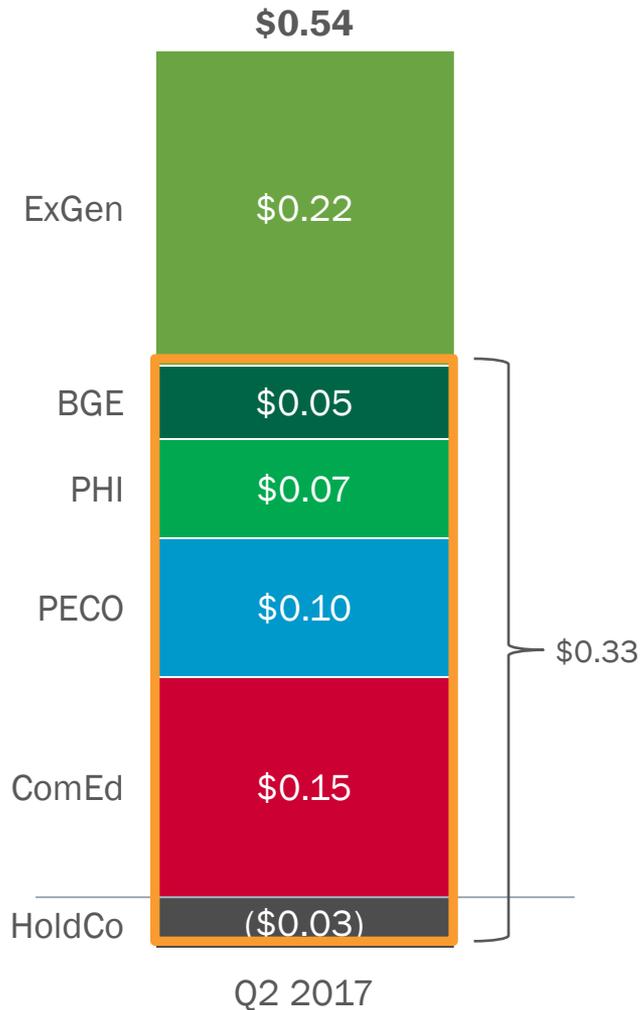
- Recognize value of resiliency by instituting operational reforms in which PJM would commit additional reserves to account for the consumer impact from the most significant potential disruption
- Refine price formation to recognize the critical contribution of all resources, including “baseload” nuclear resources

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2nd Quarter Adjusted Operating Earnings* Drivers

Q2 2017 Adjusted Operating EPS* Results

Q2 2017 vs. Guidance of \$0.45 - \$0.55



Exelon Utilities

↑ Timing of O&M

Exelon Generation

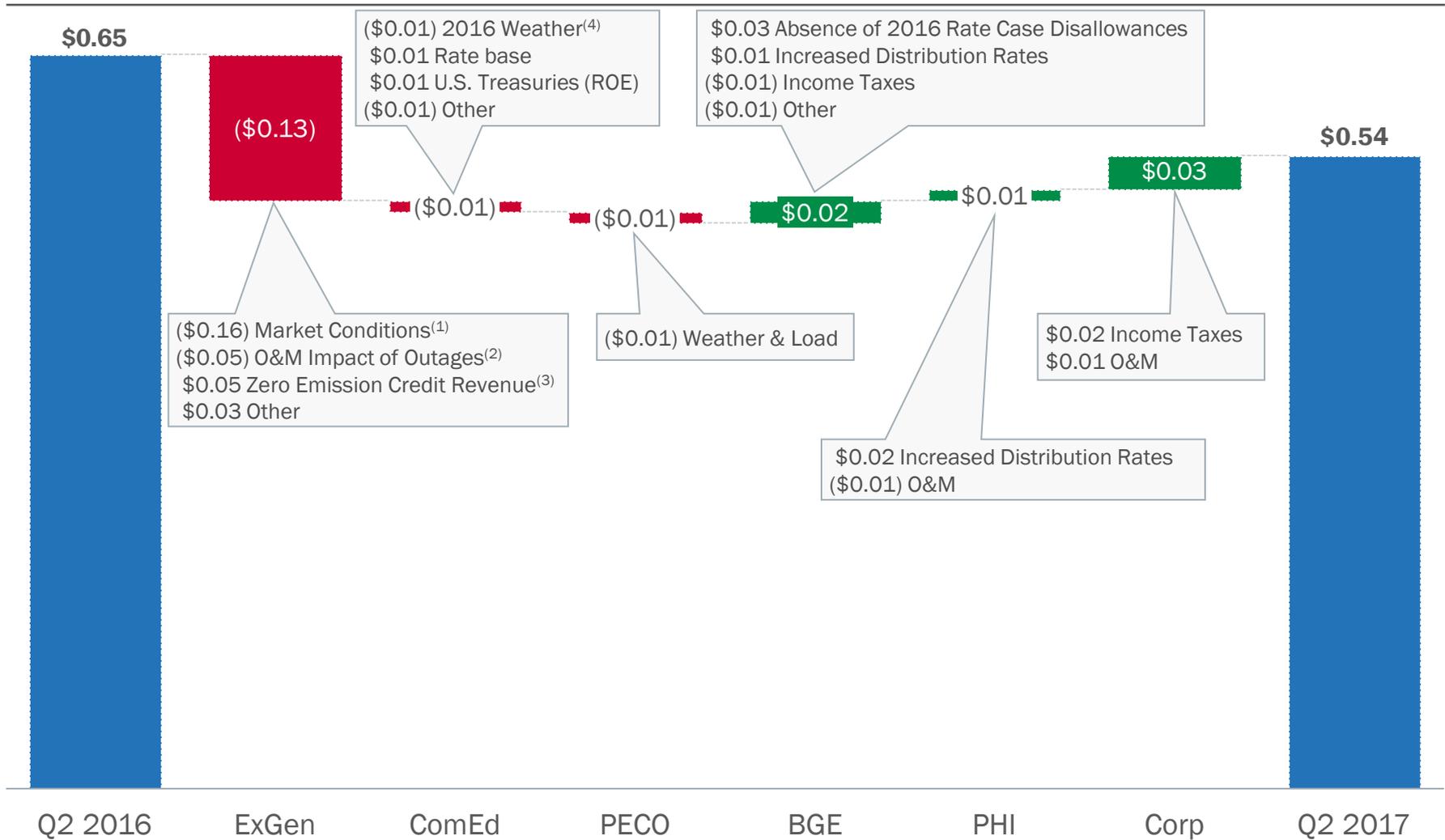
↑ Timing of O&M

↑ NDT realized gains⁽¹⁾

Note: Amounts may not sum due to rounding

(1) Gains related to unregulated sites

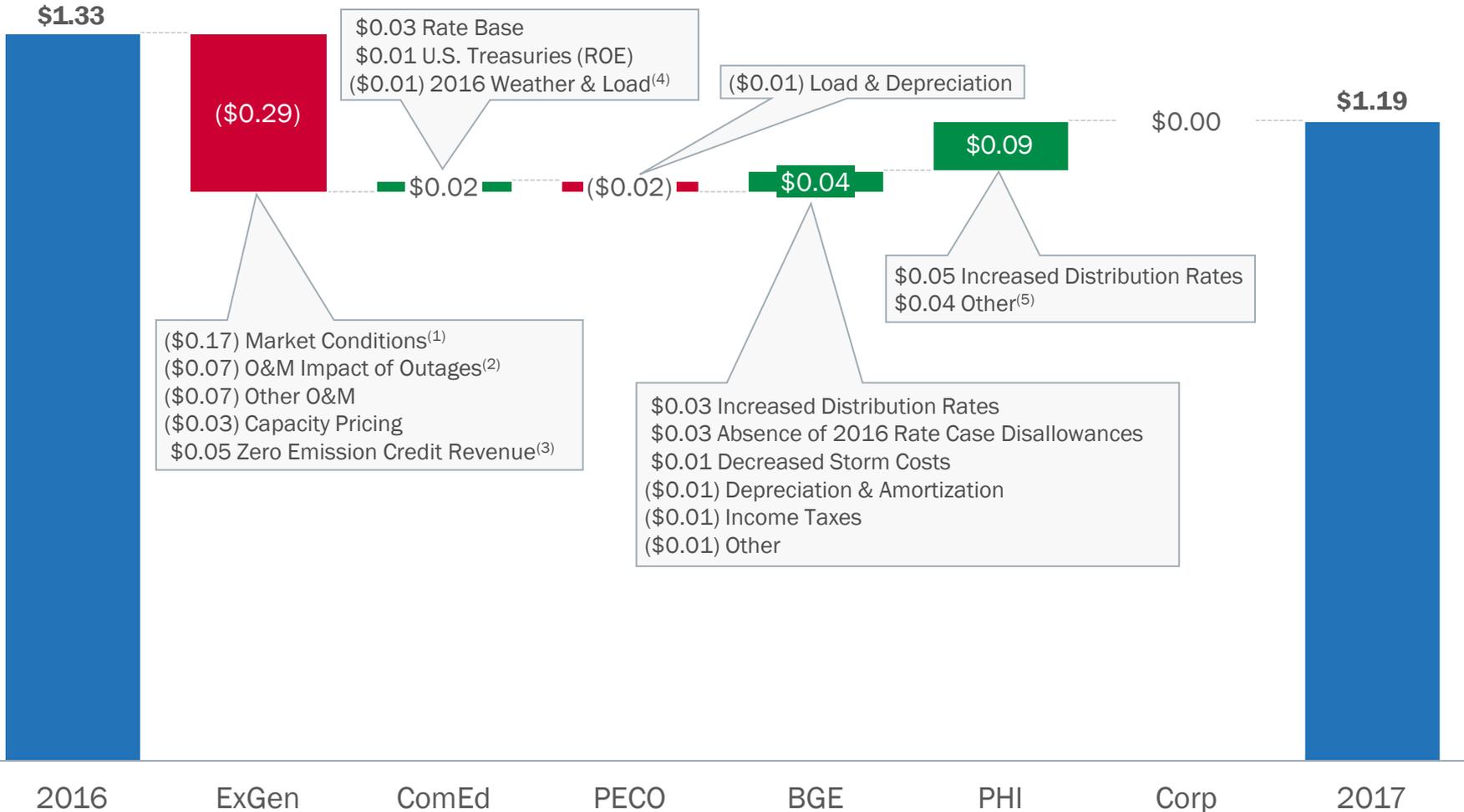
Q2 Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

- (1) Includes the unfavorable impact of the conclusion of the Ginna Reliability Support Services Agreement, lower realized energy prices and lower optimization in Generation's natural gas portfolio
- (2) Driven by higher planned outages in 2017; excludes Salem
- (3) Reflects the impact of the New York Clean Energy Standard
- (4) Pursuant to the Illinois Future Energy Jobs Act, beginning in 2017, customer rates for ComEd are adjusted to eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution volumes

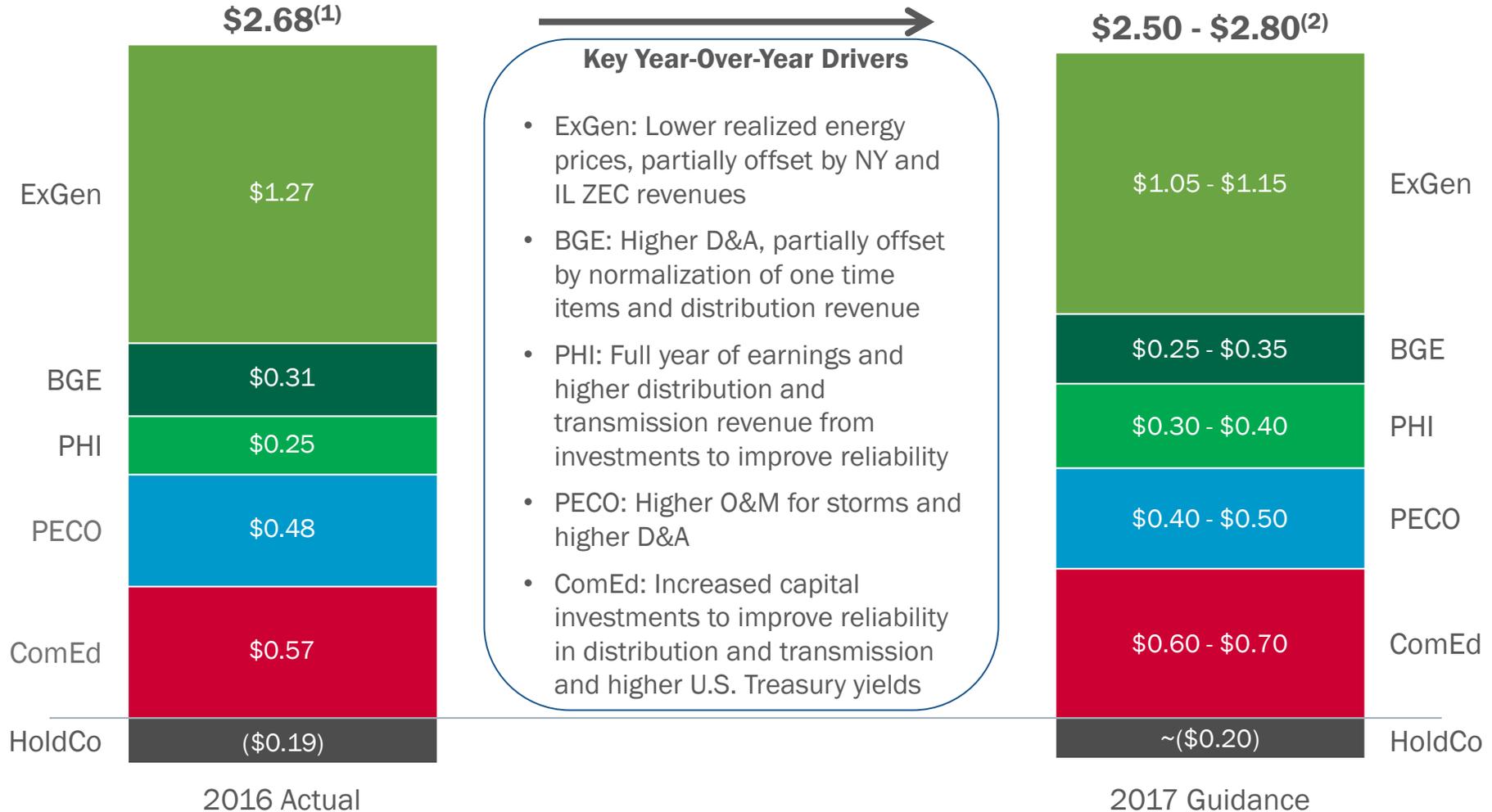
YTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

- (1) Includes the unfavorable impacts of declining natural gas prices and lower optimization in Generation's natural gas portfolio, the conclusion of the Ginna Reliability Support Services Agreement and lower realized energy prices, partially offset by the absence of oil inventory write downs that occurred in 2016
- (2) Driven by higher planned outages in 2017; excludes Salem
- (3) Reflects the impact of the New York Clean Energy Standard
- (4) Pursuant to the Illinois Future Energy Jobs Act, beginning in 2017, customer rates for ComEd are adjusted to eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution volumes
- (5) PHI reflects full six months of earnings in 2017 versus earnings from March 24, 2016 through June 30, 2016

Reaffirming 2017 Adjusted Operating Earnings* Guidance



Expect Q3 2017 Adjusted Operating Earnings* of \$0.80 - \$0.90 per share

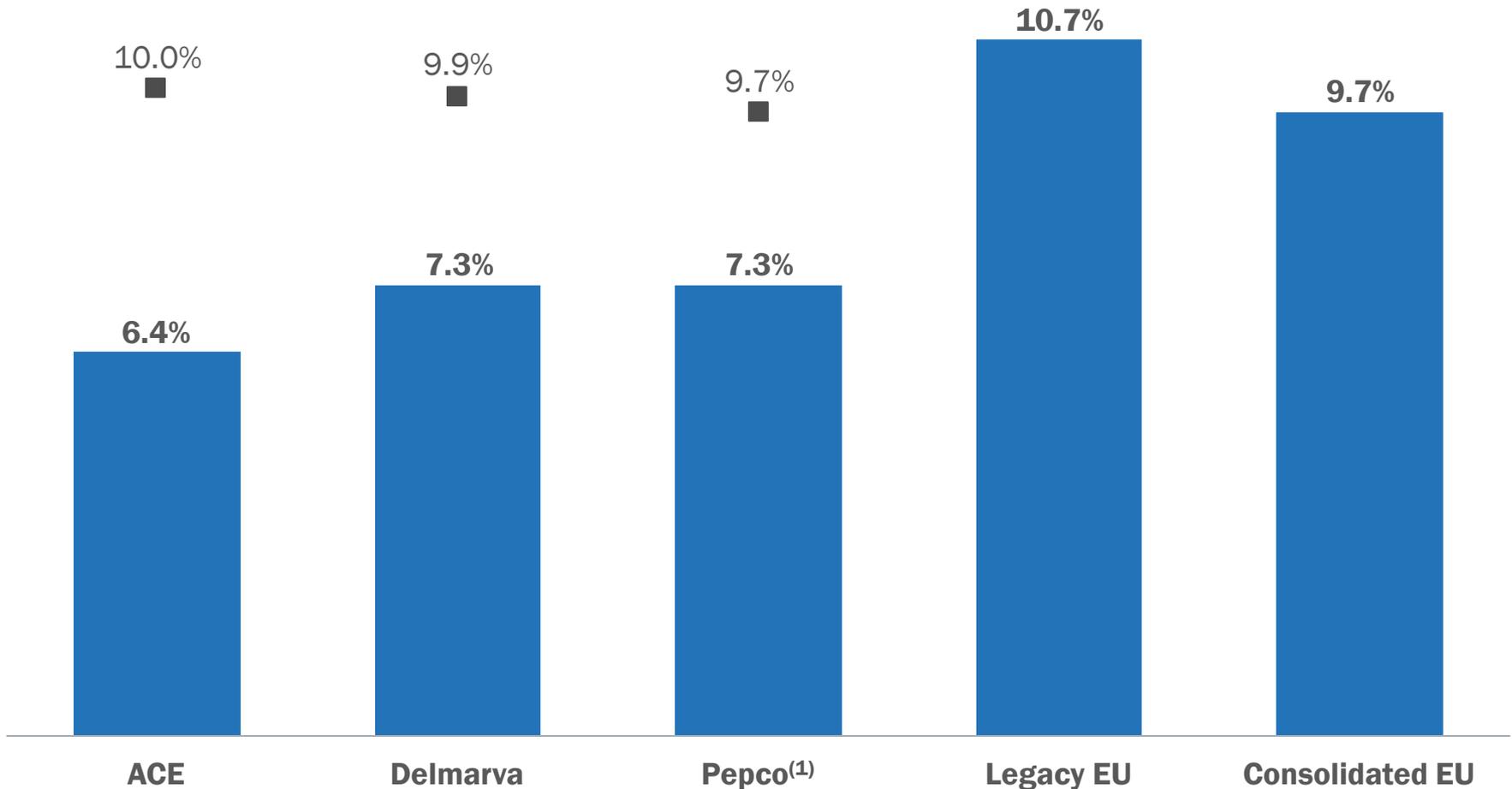
(1) 2016 results based on 2016 average outstanding shares of 927M

(2) 2017 earnings guidance based on expected average outstanding shares of 949M. Earnings guidance for OpCos may not sum up to consolidated EPS guidance.

Trailing 12 Month ROE vs Allowed ROE

Twelve Month Trailing Earned ROEs*

■ Allowed ROE ■ Earned ROE



Note: Represents the period from 6/30/16 to 6/30/17 and reflects all lines of business (Electric Distribution, Gas Distribution, and Transmission)

(1) Pepco DC Distribution allowed ROE is based on authorized ROE of 9.4% for the rates that were in effect during the trailing twelve month period. The order issued on 7/25/17 authorized an ROE of 9.5%.

Exelon Utilities Distribution Rate Case Summary

Delmarva MD Order		Pepco MD Filing	
Authorized Revenue Requirement Increase ⁽¹⁾	\$38.3M	Requested Revenue Requirement Increase ⁽¹⁾	\$68.6M
Authorized ROE	9.60%	Requested ROE	10.10%
Common Equity Ratio	49.10%	Requested Common Equity Ratio	50.15%
Order Received	2/15/17	Order Expected	10/20/17
Delmarva DE Electric Order		ACE Filing	
Authorized Revenue Requirement Increase ⁽¹⁾	\$31.5M	Requested Revenue Requirement Increase ⁽¹⁾	\$72.6M
Authorized ROE	9.70%	Requested ROE	10.10%
Common Equity Ratio	N/A	Requested Common Equity Ratio	50.14%
Order Received	5/23/17	Order Expected	Q1 2018
Delmarva DE Gas Order		Delmarva MD Filing	
Authorized Revenue Requirement Increase ⁽¹⁾	\$4.9M	Requested Revenue Requirement Increase ⁽¹⁾	\$27.0M
Authorized ROE	9.70%	Requested ROE	10.10%
Common Equity Ratio	N/A	Requested Common Equity Ratio	50.68%
Order Received	6/6/17	Order Expected	2/14/18
Pepco DC Order		ComEd Filing	
Authorized Revenue Requirement Increase ⁽¹⁾	\$36.9M	Requested Revenue Requirement Increase ⁽¹⁾	\$95.6M ⁽²⁾
Authorized ROE	9.50%	Requested ROE	8.40%
Common Equity Ratio	49.14%	Requested Common Equity Ratio	45.89%
Order Received	7/25/17	Order Expected	Q4 2017

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

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

Updates: RPM Results and TMI Closure

PJM 2020/2021 Capacity Auction

- Cleared 16.2 GW of generation capacity in 2020/2021 PJM base residual auction
- The bulk of cleared capacity was in the ComEd and EMAAC zones, which cleared above rest of RTO pricing at \$188/MW-d
- Despite volatility in PJM capacity market, capacity revenues have met or exceeded \$1B annually



TMI Closure

- Exelon announced that it will retire TMI in September 2019, absent needed policy reforms
- Announcement comes after TMI failed to clear PJM base residual auctions for the third consecutive year
- Financial impact⁽¹⁾ of TMI retirement is annual accretive EPS impact of \$0.04-\$0.07 and cumulative cash flow impact of ~\$225M through 2021



(1) Based on May 31, 2017, pricing and exclude decommissioning impacts

Exelon Generation: Gross Margin Update

Gross Margin Category (\$M) ⁽¹⁾	June 30, 2017			Change from Mar 31, 2017		
	2017	2018	2019	2017	2018	2019
Open Gross Margin ^(2,5) (including South, West, Canada hedged gross margin)	\$3,750	\$4,000	\$3,800	\$(100)	\$(150)	\$(150)
Capacity and ZEC Revenues ^(2,5)	\$1,850	\$2,200	\$2,050	-	\$(50)	-
Mark-to-Market of Hedges ^(2,3)	\$1,900	\$550	\$400	\$300	\$50	-
Power New Business / To Go	\$200	\$850	\$950	\$(200)	-	-
Non-Power Margins Executed	\$300	\$150	\$100	\$50	-	-
Non-Power New Business / To Go	\$150	\$350	\$400	\$(50)	-	-
Total Gross Margin * ^(4,5)	\$8,150	\$8,100	\$7,700	-	\$(150)	\$(150)

Recent Developments

- Executed \$200M of Power New Business in 2017
- Reflects removal of EGTP⁽⁵⁾ and TMI⁽⁵⁾
- Behind ratable hedging position reflects the fundamental upside we see in power prices
 - ~11-14% behind ratable in 2018 when considering cross commodity hedges

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

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

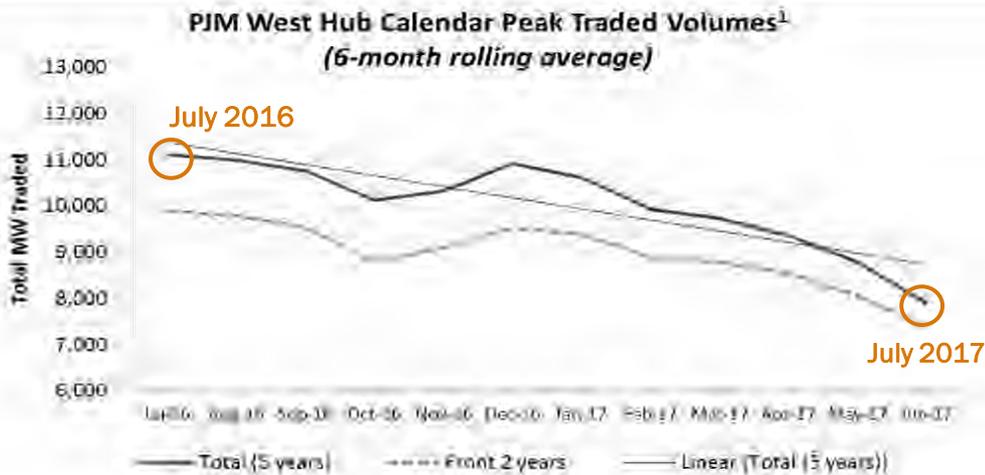
3) Mark-to-Market of Hedges assumes mid-point of hedge percentages

4) Based on June 30, 2017, market conditions

5) Reflects TMI and Oyster Creek retirements in September 2019 and December 2019, respectively. EGTP removal impacts partial year 2017 and full year 2018 and 2019. EGTP removal results in \$100M reduction to gross margin in 2018 and 2019 with positive EPS impacts of \$0.02-\$0.03. TMI retirement results in \$50M reduction in gross margin in 2019.

Forward Market Liquidity

Overall liquidity is declining



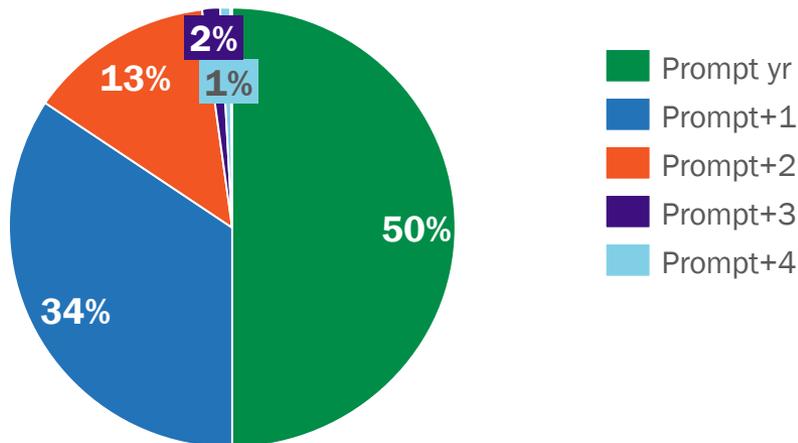
Total calendar peak traded volumes for the rolling 5-year window have been trending lower over the past year

Calendar peak traded volumes beyond prompt year +1 account for less than 10% of total traded volumes

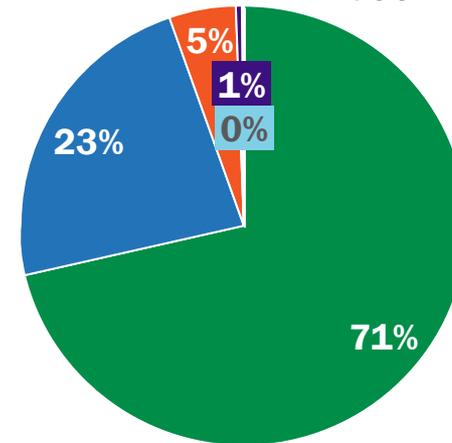
* Please note that hedging strategy utilizes various price points (i.e. NIHUB, ERCOT), channels to market (i.e. Origination, Mid-Marketing, Retail, OTC), products (i.e. calendar, seasonal), and other exchanges

Limited liquidity in the outer years

July 2016 PJM West Hub Calendar Peak Traded Volumes⁽¹⁾ (by year)



July 2017 PJM West Hub Calendar Peak Traded Volumes⁽¹⁾ (by year)



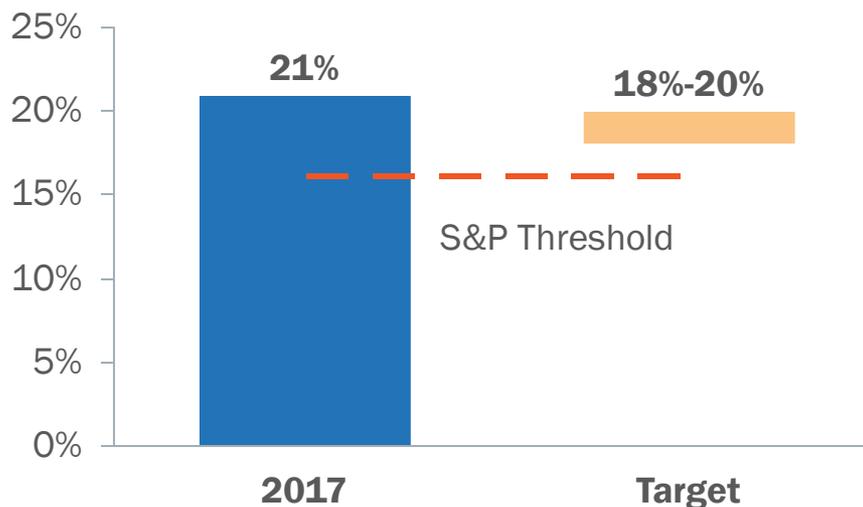
(1) Total monthly traded volumes for rolling prompt year + 4 years on ICE and NASDAQ Exchanges only

Maintaining Strong Investment Grade Credit Ratings is a Top Financial Priority

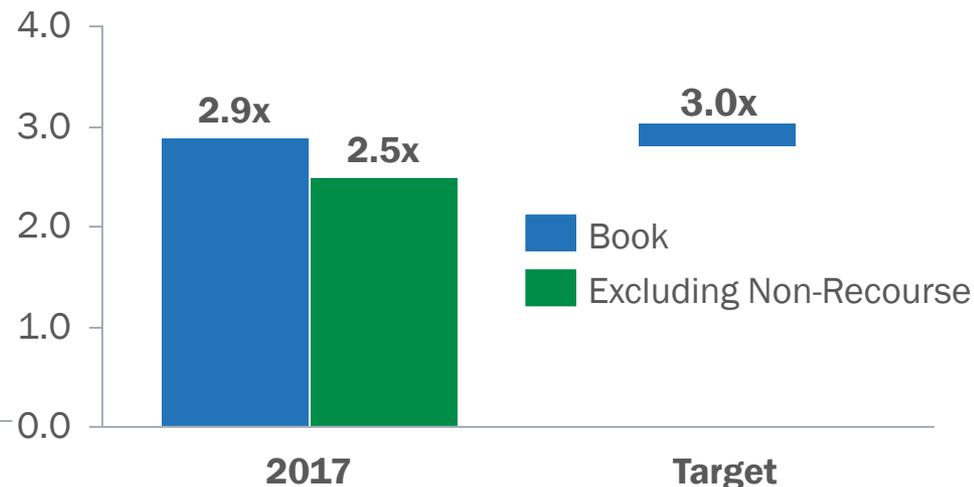
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Exelon S&P FFO/Debt %^{*(1,4,6)}



ExGen Debt/EBITDA Ratio^{*(5,6)}



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 July 26, 2017, for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco

(3) All ratings have "Stable" outlook

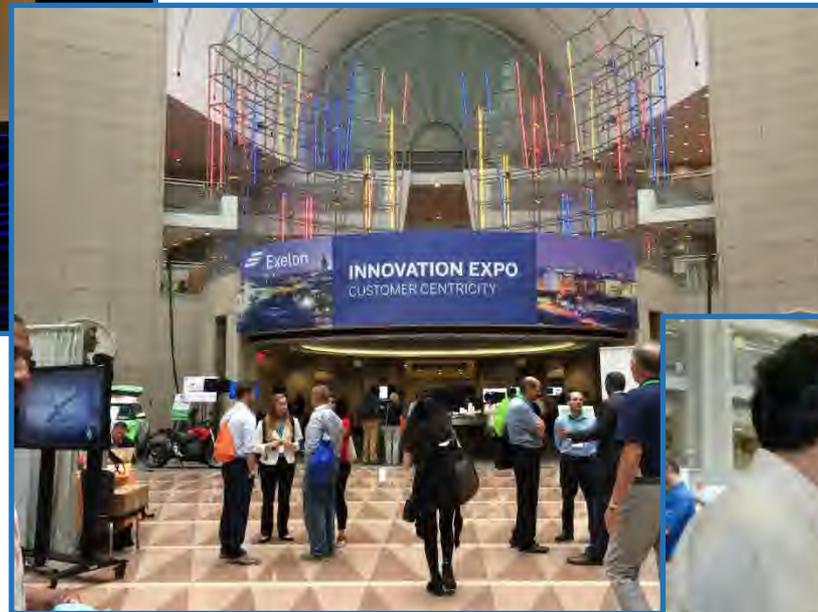
(4) Exelon Corp downgrade threshold (red dotted line) is based on the S&P Exelon Corp Summary Report; represents minimum level to maintain current Issuer Credit Rating of BBB at Exelon Corp

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

(6) Reflects removal of EGTP

Innovation Expo Highlights

- Our 2017 Innovation Expo in Washington, D.C. showcased the latest advanced technology products and processes Exelon is deploying to deliver on our commitment to provide safe, reliable, affordable and clean energy
- Exelon employees, vendors and industry experts explored how technology can solve challenges affecting the energy industry and our customers at our biggest event to date



Recognition for Stewardship and Employee Engagement

Supplier Diversity: Exelon is the only utility and energy company to be inducted into the Billion Dollar Roundtable, which recognizes corporations that have achieved spending of \$1 billion with minority and women-owned suppliers; our 2016 spend was nearly \$2B

Civic 50: Points of Light named Exelon utility sector leader in its annual ranking of the nation's most community-minded public and private companies



Top 50 Companies for Diversity: National recognition from DiversityInc, first year in Top 50 after being named a DiversityInc "Top Utility" in 2015 and 2016



Best Places to Work in 2017: Ranked No. 18 on Indeed.com survey of Fortune 500 companies based on employee reviews

CEO Action for Diversity & Inclusion™: Joined 150 leading companies in the largest CEO-driven business commitment to advance diversity and inclusion

Top 50 Most Energy-Efficient Utilities: American Council for an Energy-Efficient Economy ranks BGE and ComEd in the top 10 with PECO also making the list

Lowest Carbon Emissions: 2017 Air Emissions Benchmarking Report notes Exelon's nuclear facilities had the lowest carbon dioxide emissions of the top 20 privately held and investor-owned energy producers

The Exelon Value Proposition

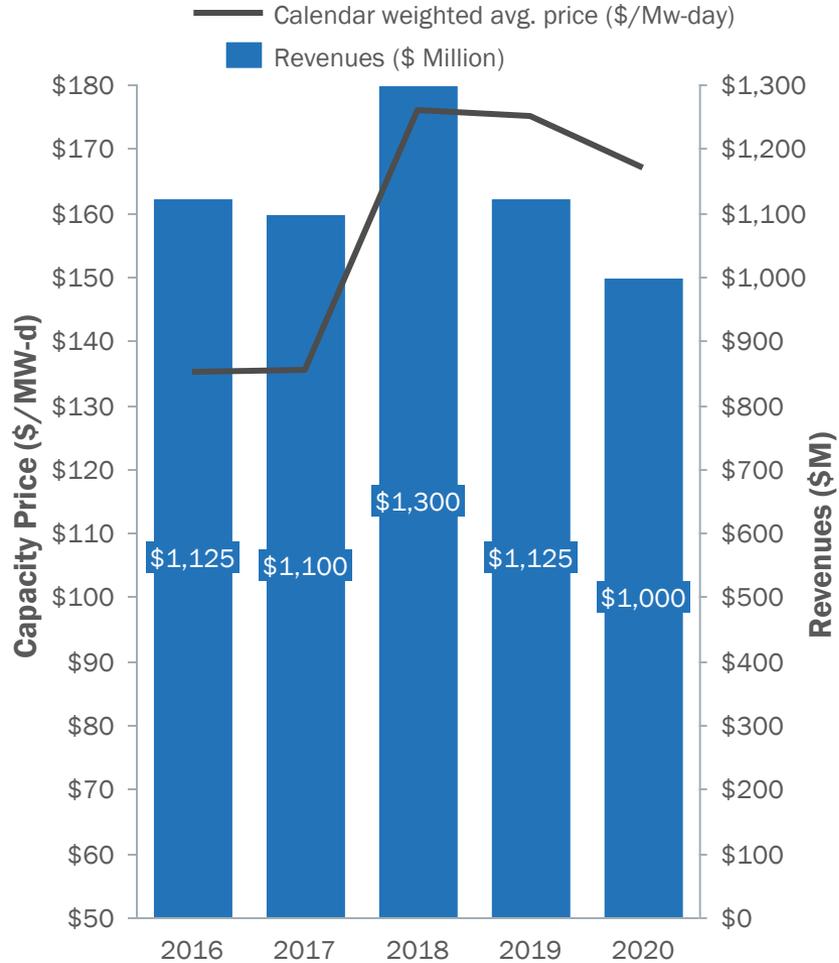
- **Regulated Utility Growth** with utility EPS rising 6-8% annually from 2017-2020 and rate base growth of 6.5%, representing an expanding majority of earnings
- **ExGen's strong free cash generation** will support utility growth while also reducing debt by ~\$3B over the next 4 years
- **Optimizing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

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

Additional Disclosures

Capacity Market: PJM

PJM Capacity Revenues^(1,2,3)



(1) Revenues reflect capacity cleared in Base, CP transitional & incremental auctions and are for calendar years

(2) Revenues reflect owned and contracted generation

(3) Reflects 50.01% ownership at CENG

(4) Volumes at ownership and rounded

Cleared Volumes (MW) ⁽⁴⁾	2019/2020				2020/2021	
	CP	Price	Base	Price	CP	Price
Comed						
Nuclear	6,925	\$203	-	\$183	8,075	\$188
Fossil/Other	-	\$203	50	\$183	-	\$188
Subtotal	6,925		50		8,075	
EMAAC						
Nuclear	4,375	\$120	-	\$100	4,350	\$188
Fossil/Other	1,525	\$120	1,675	\$100	2,325	\$188
Subtotal	5,900		1,675		6,675	
SWMAAC						
Nuclear	850	\$100	-	\$80	850	\$86
Fossil/Other	-	\$100	-	\$80	-	\$86
Subtotal	850		-		850	
MAAC						
Nuclear	-		-		-	\$86
Fossil/Other	-		-		225	\$86
Subtotal	-		-		225	
BGE						
Nuclear	-	\$100	-	\$80	-	\$86
Fossil/Other	375	\$100	225	\$80	375	\$86
Subtotal	375		225		375	
Rest of RTO						
Nuclear	-	\$100	-	\$80	-	\$77
Fossil/Other	275	\$100	75	\$80	-	\$77
Subtotal	275		75		-	
PJM Total						
Nuclear	12,150		-		13,275	
Fossil/Other	2,175		2,025		2,925	
Grand Total	14,325		2,025		16,200	

2017 Projected Sources and Uses of Cash

(\$M) ⁽¹⁾	BGE	ComEd	PECO	PHI	Total Utilities	ExGen	Corp ⁽⁹⁾	Exelon 2017E	Cash Balance
Beginning Cash Balance * ⁽²⁾									1,050
Adjusted Cash Flow from Operations* ⁽³⁾	700	800	750	1,150	3,425	3,425	100	6,950	
Base CapEx and Nuclear Fuel ⁽⁴⁾	0	0	0	0	0	(2,025)	(50)	(2,075)	
Free Cash Flow*	700	800	750	1,150	3,425	1,400	50	4,875	
Debt Issuances	250	1,000	325	200	1,775	750	1,150	3,675	
Debt Retirements	(300)	(425)	0	(150)	(875)	(700)	(1,700)	(3,275)	
Project Financing	n/a	n/a	n/a	n/a	n/a	275	n/a	275	
Equity Issuance/Share Buyback	0	0	0	0	0	0	1,150	1,150	
Contribution from Parent	150	675	0	825	1,650	0	(1,650)	(25)	
Other Financing ⁽⁵⁾	300	525	150	(375)	600	75	425	1,100	
Financing * ⁽⁶⁾	400	1,775	475	500	3,150	375	(650)	2,875	
Total Free Cash Flow and Financing	1,125	2,575	1,200	1,650	6,550	1,775	(600)	7,750	
Utility Investment	(925)	(2,200)	(775)	(1,375)	(5,250)	0	0	(5,250)	
ExGen Growth ^(4,7)	0	0	0	0	0	(825)	0	(825)	
Acquisitions and Divestitures	0	0	0	0	0	0	0	0	
Equity Investments	0	0	0	0	0	(50)	0	(50)	
Dividend ⁽⁸⁾	0	0	0	0	0	0	(1,225)	(1,225)	
Other CapEx and Dividend	(925)	(2,200)	(775)	(1,375)	(5,250)	(875)	(1,225)	(7,375)	
Total Cash Flow	200	400	450	275	1,300	900	(1,825)	375	
Ending Cash Balance * ⁽²⁾									1,425

- (1) All amounts rounded to the nearest \$25M. Figures may not add due to rounding.
- (2) Gross of posted counterparty collateral
- (3) Excludes counterparty collateral activity
- (4) Figures reflect cash CapEx and CENG fleet at 100%
- (5) Other Financing includes expected changes in short-term debt, money pool borrowings, tax sharing from the parent, debt issue costs, CENG credit facility, tax equity cash flows, Renewable JV, and capital leases
- (6) Financing cash flow excludes intercompany dividends and other intercompany financing activities
- (7) ExGen Growth CapEx primarily includes Texas CCGTs, AGE, W. Medway, Retail Solar, and Retail Growth
- (8) Dividends are subject to declaration by the Board of Directors
- (9) 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 \$4.9B of free cash flow, including \$1.4B at ExGen and \$3.4B at the Utilities

Supported by a strong balance sheet

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

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

Enable growth & value creation

Creating value for customers, communities and shareholders

- ✓ Investing \$6.0B, with \$5.3B at the Utilities and \$0.8B at ExGen

Exelon Generation Disclosures

June 30, 2017

Portfolio Management Strategy

Strategic Policy Alignment

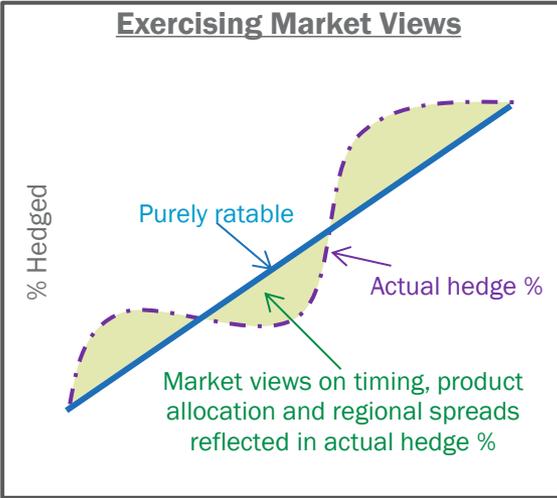
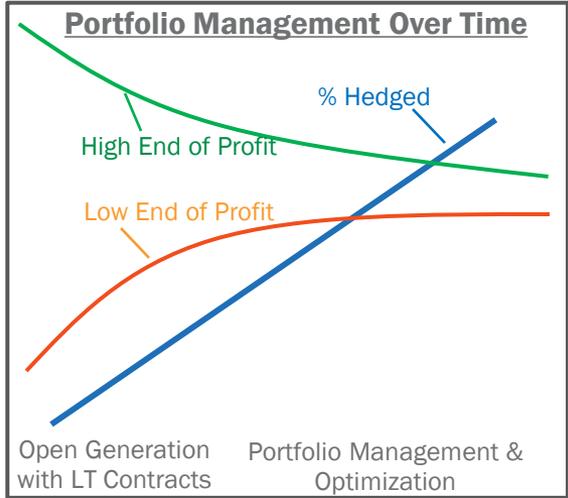
- Aligns hedging program with financial policies and financial outlook
- Establish minimum hedge targets to meet financial objectives of the company (dividend, credit rating)
- Hedge enough commodity risk to meet future cash requirements under a stress scenario

Three-Year Ratable Hedging

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

Bull / Bear Program

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



Protect Balance Sheet

Ensure Earnings Stability

Create Value

Components of Gross Margin Categories

Gross margin linked to power production and sales

Open Gross Margin

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

Capacity and ZEC Revenues

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

MtM of Hedges⁽²⁾

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

“Power” New Business

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

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

Gross margin from other business activities

“Non Power” Executed

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

“Non Power” New Business

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

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

(1) Hedged gross margins for South, West & Canada region will be included with Open Gross Margin; no expected generation, hedge %, EREP or reference prices provided for this region

(2) MtM of hedges provided directly for the five larger regions; MtM of hedges is not provided directly at the regional level but can be easily estimated using EREP, reference price and hedged MWh

(3) Proprietary trading gross margins will generally remain within “Non Power” New Business category and only move to “Non Power” Executed category upon management discretion

(4) Gross margin for these businesses are net of direct “cost of sales”

(5) Margins for South, West & Canada regions and optimization of fuel and PPA activities captured in Open Gross Margin

ExGen Disclosures

Gross Margin Category (\$M) ⁽¹⁾	2017	2018	2019
Open Gross Margin (including South, West & Canada hedged GM) ^(2,5)	\$3,750	\$4,000	\$3,800
Capacity and ZEC Revenues ^(2,5)	\$1,850	\$2,200	\$2,050
Mark-to-Market of Hedges ^(2,3)	\$1,900	\$550	\$400
Power New Business / To Go	\$200	\$850	\$950
Non-Power Margins Executed	\$300	\$150	\$100
Non-Power New Business / To Go	\$150	\$350	\$400
Total Gross Margin*⁽⁵⁾	\$8,150	\$8,100	\$7,700

Reference Prices ⁽⁴⁾	2017	2018	2019
Henry Hub Natural Gas (\$/MMbtu)	\$3.17	\$2.99	\$2.85
Midwest: NiHub ATC prices (\$/MWh)	\$26.97	\$27.81	\$26.90
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$28.94	\$30.55	\$29.31
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	\$0.69	\$2.26	\$3.33
New York: NY Zone A (\$/MWh)	\$25.70	\$27.95	\$27.13
New England: Mass Hub ATC Spark Spread(\$/MWh) <i>ALQN Gas, 7.5HR, \$0.50 VOM</i>	\$4.62	\$4.90	\$5.00

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

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

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

4) Based on June 30, 2017, market conditions

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

ExGen Disclosures

Generation and Hedges	2017	2018	2019
<u>Exp. Gen (GWh)⁽¹⁾</u>	203,500	200,700	202,500
Midwest	96,000	96,000	97,000
Mid-Atlantic ^(2,6)	60,500	60,300	58,500
ERCOT	20,400	20,700	21,600
New York ^(2,6)	14,600	15,400	16,600
New England	12,000	8,300	8,800
<u>% of Expected Generation Hedged⁽³⁾</u>	96%-99%	71%-74%	39%-42%
Midwest	96%-99%	66%-69%	34%-37%
Mid-Atlantic ^(2,6)	100%-103%	80%-83%	45%-48%
ERCOT	86%-89%	65%-68%	46%-49%
New York ^(2,6)	94%-97%	72%-75%	38%-41%
New England	97%-100%	81%-84%	44%-47%
<u>Effective Realized Energy Price (\$/MWh)⁽⁴⁾</u>			
Midwest	\$33.00	\$29.50	\$29.50
Mid-Atlantic ^(2,6)	\$42.50	\$37.00	\$39.50
ERCOT ⁽⁵⁾	\$9.00	\$3.00	\$3.00
New York ^(2,6)	\$41.50	\$34.50	\$31.00
New England ⁽⁵⁾	\$20.00	\$4.50	\$3.50

(1) Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 15 refueling outages in 2017, 15 in 2018, and 11 in 2019 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 93.4%, 93.3% and 94.7% in 2017, 2018, and 2019, respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2018 and 2019 do not represent guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years.

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

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

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

(5) Spark spreads shown for ERCOT and New England

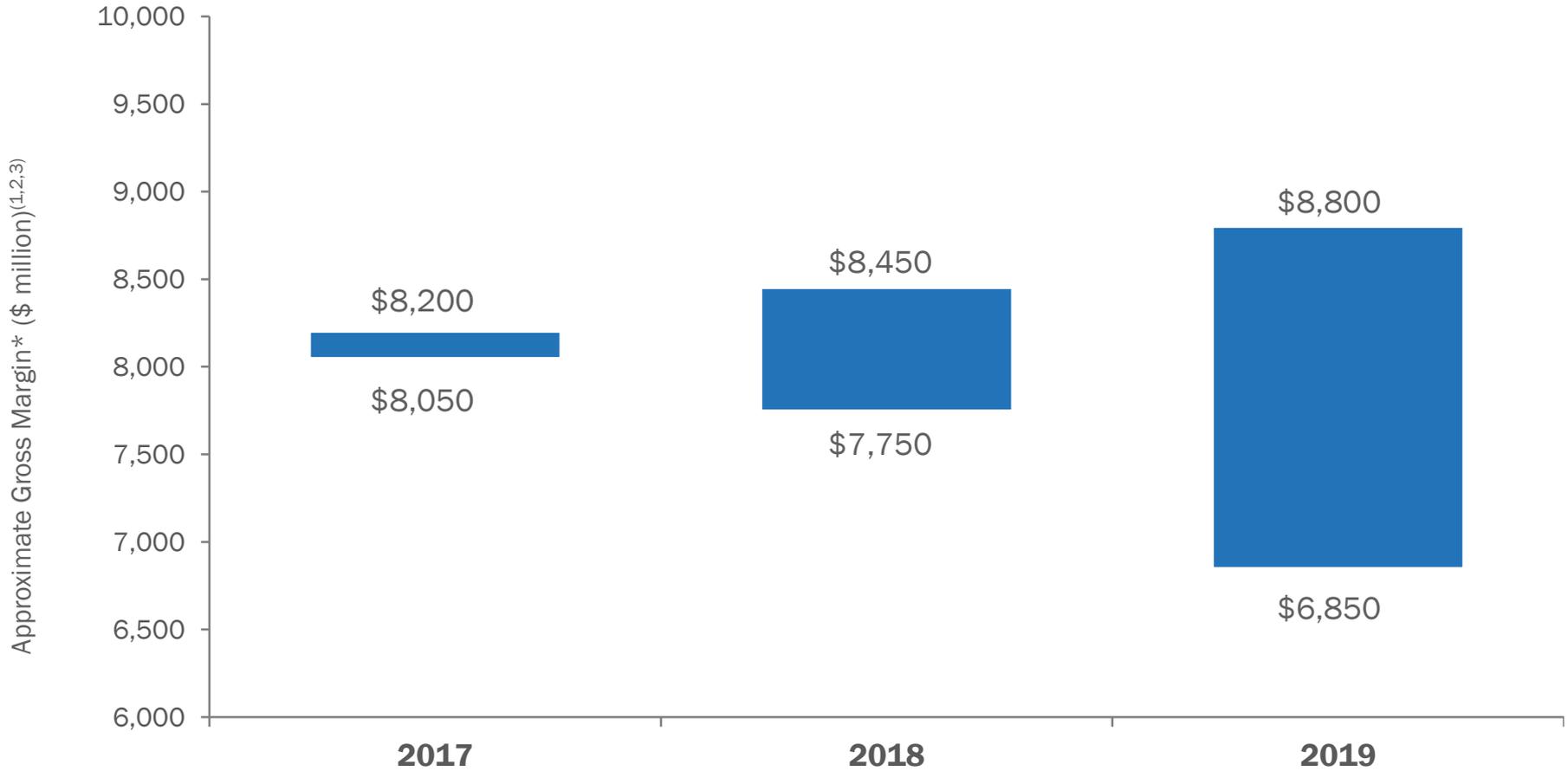
(6) Reflects ownership of FitzPatrick as of April 1, 2017, and TMI and Oyster Creek retirements in September 2019 and December 2019, respectively. EGTP removal impacts partial year 2017 and full year 2018 and 2019.

ExGen Hedged Gross Margin* Sensitivities

Gross Margin* Sensitivities (with Existing Hedges) ⁽¹⁾	2017	2018	2019
Henry Hub Natural Gas (\$/Mmbtu)			
+ \$1/Mmbtu	\$25	\$240	\$555
- \$1/Mmbtu	\$30	\$(220)	\$(540)
NiHub ATC Energy Price			
+ \$5/MWh	-	\$145	\$300
- \$5/MWh	-	\$(145)	\$(295)
PJM-W ATC Energy Price			
+ \$5/MWh	-	\$65	\$165
- \$5/MWh	\$5	\$(70)	\$(155)
NYPP Zone A ATC Energy Price			
+ \$5/MWh	-	\$20	\$45
- \$5/MWh	\$(5)	\$(20)	\$(50)
Nuclear Capacity Factor			
+/- 1%	+/- \$20	+/- \$35	+/- \$35

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

ExGen Hedged Gross Margin* Upside/Risk



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

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

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

Illustrative Example of Modeling Exelon Generation 2018 Gross Margin*

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 billion —————→						
(B)	Capacity and ZEC	←————— \$2.2 billion —————→						
(C)	Expected Generation (TWh)	96.0	60.3	20.7	15.4	8.3		
(D)	Hedge % (assuming mid-point of range)	67.5%	81.5%	66.5%	73.5%	82.5%		
(E=C*D)	Hedged Volume (TWh)	64.8	49.1	13.8	11.3	6.8		
(F)	Effective Realized Energy Price (\$/MWh)	\$29.50	\$37.00	\$3.00	\$34.50	\$4.50		
(G)	Reference Price (\$/MWh)	\$27.81	\$30.55	\$2.26	\$27.95	\$4.90		
(H=F-G)	Difference (\$/MWh)	\$1.69	\$6.45	\$0.74	\$6.55	(\$0.40)		
(I=E*H)	Mark-to-Market value of hedges (\$ million) ⁽¹⁾	\$110	\$315	\$10	\$75	(\$5)		
(J=A+B+I)	Hedged Gross Margin (\$ million)	\$6,750						
(K)	Power New Business / To Go (\$ million)	\$850						
(L)	Non-Power Margins Executed (\$ million)	\$150						
(M)	Non-Power New Business / To Go (\$ million)	\$350						
(N=J+K+L+M)	Total Gross Margin*	\$8,100 million						

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

Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in \$M) ⁽¹⁾	2017	2018	2019
Revenue Net of Purchased Power and Fuel Expense^{*(2,3)}	\$8,675	\$8,725	\$8,300
Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at merger date	\$50	-	-
Other Revenues ⁽⁴⁾	\$(150)	\$(225)	\$(200)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses ⁽⁵⁾	\$(425)	\$(400)	\$(400)
Total Gross Margin* (Non-GAAP)	\$8,150	\$8,100	\$7,700

Key ExGen Modeling Inputs (in \$M) ^(1,6)	2017
Other ⁽⁷⁾	\$150
Adjusted O&M*	\$(4,850)
Taxes Other Than Income (TOTI) ⁽⁸⁾	\$(375)
Depreciation & Amortization ⁽⁹⁾	\$(1,100)
Interest Expense ⁽¹⁰⁾	\$(400)
Effective Tax Rate	32.0%

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

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

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

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

(5) Reflects the cost of sales of certain Constellation and Power businesses

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

(7) Other reflects Other Revenues excluding gross receipts tax revenues, nuclear decommissioning trust fund earnings from unregulated sites, and the minority interest in ExGen Renewables JV and Bloom

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

(9) Excludes P&L neutral decommissioning depreciation

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

Exelon Utilities Rate Case Filing Summaries

Exelon Utilities Distribution Rate Case Schedule

	6/17	7/17	8/17	9/17	10/17	11/17	12/17
ComEd Electric Distribution Formula Rate		Rebuttal Testimony Mid-July	Hearings August 28		Proposed Order October 19		Commission Order Expected December 9
Pepco Electric Distribution Rates - DC		Commission Order Received July 25					
Pepco Electric Distribution Rates - MD	Intervenor Direct Testimony June 30		Rebuttal Testimony Aug. 1	Evidentiary Hearings Sept. 5-15	Commission Order Expected Oct. 20		
Delmarva Electric Distribution Rates - MD		Rate Case Filed July 14					
ACE Electric Distribution Rates - NJ			Intervenor Direct Testimony Aug. 1	Rebuttal Testimony Sept. 6	Evidentiary Hearings Oct. 2-13		

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

Delmarva DE (Electric) Distribution Rate Case Final Order

Docket #	16-0649	Approved Black Box Settlement
Test Year	2015 Calendar Year	
Test Period	12 months actual	
Authorized Common Equity Ratio	49.44%	
Authorized Rate of Return	ROE: 10.60%; ROR: 7.19%	ROE: 9.70%
Rate Base⁽¹⁾	\$839M	
Authorized Revenue Requirement Increase^(2,3)	\$60.2M	\$31.5M Revenue increase includes approx. \$7.5M of new depreciation and amortization expense
Residential Total Bill % Increase	7.25%	4.80%
Notes	<ul style="list-style-type: none"> • 5/17/16 DPL DE filed application with the Delaware Public Service Commission (DPSC) seeking increase in electric distribution base rates • 18 month forward-looking reliability and other plant additions from January 2016 through June 2017 (\$8.4M of Revenue Requirement based on 10.60% ROE) included in revenue requirement request • Includes the Pay as You Go Program, a proposed pilot program that would be cooperatively designed to use the capability of the AMI meters to offer a voluntary pre-paid metering option for customers 	<ul style="list-style-type: none"> • 3/8/17 Unanimous settlement filed with the DPSC • New depreciation rates included in the revenue increase • Recovery of \$28.6M of direct load control and dynamic pricing regulatory assets to be amortized over 10 years • Approval to establish regulatory asset for costs to achieve synergy savings, amortized over 5 years • Actual synergy savings and costs to achieve will be reviewed in next base rate proceeding • Commission Approved Settlement: 5/23/17 • Rates effective June 1; no interim rate refunds

(1) The Settlement is a partial "black box settlement" meaning that the Settling Parties have agreed to some terms in the Settlement, but not others. No adjusted rate base or earnings were documented.

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

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

Delmarva DE (Gas) Distribution Rate Case Final Order

Docket #	16-0650	Approved Black Box Settlement
Test Year	2015 Calendar Year	
Test Period	12 months actual	
Common Equity Ratio	49.44%	
Rate of Return	ROE: 10.60%; ROR: 7.19%	ROE: 9.70%
Rate Base ⁽¹⁾	\$362M	
Revenue Requirement Increase ^(2,3)	\$22.2M	\$4.9M Revenue increase includes net reduction of \$4.8M in new depreciation and amortization expense
Residential Total Bill % Increase	10.40%	2.70%
Notes	<ul style="list-style-type: none"> 5/17/16 DPL DE filed application with the DPSC seeking increase in gas distribution base rates 	<ul style="list-style-type: none"> 4/6/17 Unanimous settlement filed with the DPSC New depreciation rates included in the revenue increase Incremental labor costs for the Interface Management Unit (IMU) battery replacement project deferred into a regulatory asset for review in a future proceeding Approval to establish regulatory asset for costs to achieve synergy savings, amortized over 5 years Actual synergy savings and costs to achieve will be reviewed against actuals in next base rate proceeding Commission approved settlement: 6/6/17 Rates effective July 1 Refund will be issued for amounts collected, under interim rates, in excess of \$4.9M revenue requirement increase

(1) The Settlement is a partial "black box settlement" meaning that the Settling Parties have agreed to some terms in the Settlement, but not others. No adjusted rate base or earnings were documented.

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

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

Pepco DC Rate Case Final Order

Formal Case No.	1139	Per Commission Order
Test Year	April 1, 2015 – March 31, 2016	
Test Period	12 months actual	
Requested Common Equity Ratio	49.14%	49.14%
Requested Rate of Return	ROE: 10.60%; ROR: 8.00%	ROE: 9.50%; ROR: 7.46%
Proposed Rate Base (Adjusted)	\$1.7B	\$1.6B
Requested Revenue Requirement Increase	\$76.8M ⁽¹⁾	\$36.9M EBIT impact is currently estimated at \$39M related to new items per the Order
Residential Total Bill % Increase	4.62%	2.52%
Notes	<ul style="list-style-type: none"> 6/30/16 Pepco filed application with District of Columbia Public Service Commission (DCPSC) seeking increase in electric distribution base rates <p>Intervenor Positions:</p> <ul style="list-style-type: none"> Office of People’s Council (OPC) revenue increase of \$25.8M based on 8.60% ROE Apartment and Office Building Association (AOBA) revenue increase of \$62.2M based on 9.25% ROE Healthcare Council of the National Capital Area (HCNCA) revenue increase of \$16.8M based on 8.75% ROE District of Columbia Water and Sewer Authority (DC Water) revenue increase of \$52.7M based on 9.10% ROE 	<ul style="list-style-type: none"> 7/25/17 DCPSC issued Final Order Bill Stabilization Adjustment (BSA) remains unchanged Approval to establish regulatory asset for costs to achieve (CTA) Customer Base Rate Credit (CBRC) will offset monthly bill increases <ul style="list-style-type: none"> \$15M allocated to residential customers \$2.3M designated to certain small commercial customers \$6-7M reserved for disabled and senior citizens on fixed incomes in future rate cases Recovery of \$27.4M of AMI, direct load control and dynamic pricing regulatory assets to be amortized over 5 years

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

Pepco MD Rate Case Filing

Formal Case No.	9443
Test Year	May 1, 2016 – April 30, 2017
Test Period	8 months actual and 4 months estimated
Requested Common Equity Ratio	50.15%
Requested Rate of Return	ROE: 10.10%; ROR: 7.74%
Proposed Rate Base (Adjusted)	\$1.7B
Requested Revenue Requirement Increase⁽¹⁾	\$68.6M
Residential Total Bill % Increase	5.6%
Notes	<ul style="list-style-type: none"> • 3/24/17 Pepco MD filed application with the Maryland Public Service Commission (MDPSC) seeking increase in electric distribution base rates • Size of ask is driven by Continued Investments in the electric distribution system to maintain and increase reliability and customer service • Normalization of tax benefits on pre-1981 removal costs • 8 month forward looking reliability and other plant additions from May 2017 through December 2017 (\$13.3M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request • Company is seeking recovery of the restoration portion of the Supplemental Executive Retirement Plan (SERP) <p>Procedural Schedule:</p> <ul style="list-style-type: none"> • Intervenor Direct Testimony Due: 6/30/17 • Rebuttal Testimony Due: 8/1/17 • Evidentiary Hearings: 9/5/17 – 9/15/17 • Brief Due: 10/3/17 • Commission Order Expected: 10/20/17

(1) Revenue requirement includes changes in depreciation and amortization expense, which have no impact on pre-tax earnings. Updated June 7, 2017.

Atlantic City Electric NJ Rate Case Filing

BPU Docket No.	ER17030308
Test Year	August 1, 2016 – July 31, 2017
Test Period	5 months actual and 7 months estimated
Requested Common Equity Ratio	50.14%
Requested Rate of Return	ROE: 10.10%; ROR: 7.83%
Proposed Rate Base (Adjusted)	\$1.4B
Requested Revenue Requirement Increase⁽¹⁾	\$72.6M
Residential Total Bill % Increase	6.57%
Notes	<ul style="list-style-type: none"> • 3/30/17 ACE filed application with the New Jersey Board of Public Utilities (NJBPU) seeking increase in electric distribution base rates • Recovery of investment in infrastructure to maintain and harden the electric distribution system • Ratemaking adjustments to address declining sales • 8 month forward-looking reliability and other plant additions from August 2017 through March 2018 (\$8.4M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request • Proposal of a Non-Incremental System Renewal Recovery Charge for recovery of non-incremental reliability spend over four years (2018-2021) of \$376 million. <p>Procedural Schedule:</p> <ul style="list-style-type: none"> • Settlement Meeting: 7/17/17 • Intervenor Direct Testimony Due: 8/1/17 • Rebuttal Testimony Due: 9/6/17 • Evidentiary Hearings: 10/2/17 – 10/13/17 • Commission Order Expected: March 2018

(1) Updated on July 14, 2017

Delmarva Power & Light MD Rate Case Filing

Formal Case No.	9455
Test Year	October 1, 2016 – September 30, 2017
Test Period	7 months actual and 5 months estimated
Requested Common Equity Ratio	50.68%
Requested Rate of Return	ROE: 10.10%; ROR: 7.05%
Proposed Rate Base (Adjusted)	\$791M
Requested Revenue Requirement Increase	\$27.0M
Residential Total Bill % Increase	1.9%
Notes	<ul style="list-style-type: none"> • 7/14/17 DPL MD filed application with the Maryland Public Service Commission (MDPSC) seeking increase in electric distribution base rates • Size of ask is driven by continued investments in the electric distribution system to maintain and increase reliability and customer service • Forward looking reliability and other plant additions through April 2018 (\$3.1M of Revenue Requirement based on 10.10% ROE) included in revenue requirement request • Requested year end rate base treatment (\$4.1M of Revenue Requirement based on 10.10% ROE) • Commission Order expected: 2/14/18

ComEd April 2017 Distribution Formula Rate

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

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

Docket #	17-0196
Filing Year	2016 Calendar Year Actual Costs and 2017 Projected Net Plant Additions are used to set the rates for calendar year 2018. Rates currently in effect (docket 16-0259) for calendar year 2017 were based on 2015 actual costs and 2016 projected net plant additions.
Reconciliation Year	Reconciles Revenue Requirement reflected in rates during 2016 to 2016 Actual Costs Incurred. Revenue requirement for 2016 is based on docket 15-0287 (2014 actual costs and 2015 projected net plant additions) approved in December 2015.
Common Equity Ratio	~ 46% for both the filing and reconciliation year
ROE	8.40% for the filing year (2016 30-yr Treasury Yield of 2.60% + 580 basis point risk premium) and 8.34% for the reconciliation year (2016 30-yr Treasury Yield of 2.60% + 580 basis point risk premium – 6 basis points performance metrics penalty). For 2017 and 2018, the actual allowed ROE reflected in net income will ultimately be based on the average of the 30-year Treasury Yield during the respective years plus 580 basis point spread, absent any metric penalties
Requested Rate of Return	~ 6.5% for both the filing and reconciliation years
Rate Base⁽¹⁾	\$9,662 million – Filing year (represents projected year-end rate base using 2016 actual plus 2017 projected capital additions). 2017 and 2018 earnings will reflect 2017 and 2018 year-end rate base respectively. \$8,807 million - Reconciliation year (represents year-end rate base for 2016)
Revenue Requirement Increase⁽¹⁾	\$95.6M increase (\$17.5M increase due to the 2016 reconciliation and collar adjustment in addition to a \$78.1M increase related to the filing year). The 2016 reconciliation impact on net income was recorded in 2016 as a regulatory asset.
Timeline	<ul style="list-style-type: none"> • 04/13/17 Filing Date • 240 Day Proceeding • ICC Order on FRU expected to be issued by December 9, 2017

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

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

Appendix

Reconciliation of Non-GAAP Measures

Q2 2016 QTD GAAP EPS Reconciliation

<u>Three Months Ended June 30, 2016</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>PHI</u>	<u>Other</u>	<u>Exelon</u>
2016 GAAP Earnings (Loss) Per Share	\$0.00	\$0.16	\$0.11	\$0.03	\$0.06	(\$0.06)	\$0.29
Mark-to-market impact of economic hedging activities	0.20	-	-	-	-	-	0.20
Unrealized gains related to NDT fund investments	(0.03)	-	-	-	-	-	(0.03)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Long-Lived asset impairments	0.02	-	-	-	-	-	0.02
Plant retirements and divestitures	0.14	-	-	-	-	-	0.14
Cost management program	-	-	-	-	-	-	0.01
CENG noncontrolling interest	0.01	-	-	-	-	-	0.01
2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.35	\$0.16	\$0.11	\$0.03	\$0.06	\$(0.06)	\$0.65

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

Q2 2017 QTD GAAP EPS Reconciliation (continued)

Three Months Ended June 30, 2017	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2017 GAAP (Loss) Earnings Per Share	(\$0.27)	\$0.13	\$0.09	\$0.05	\$0.07	\$0.02	\$0.09
Mark-to-market impact of economic hedging activities	0.12	-	-	-	-	-	0.12
Unrealized gains related to NDT fund investments	(0.05)	-	-	-	-	-	(0.05)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	0.01	-	-	-	-	-	0.01
Long-lived asset impairments	0.29	-	-	-	-	-	0.29
Plant retirements and divestitures	0.07	-	-	-	-	-	0.07
Cost management program	-	-	-	-	-	-	0.01
Like-kind exchange tax position	-	0.02	-	-	-	(0.05)	(0.03)
CENG noncontrolling interest	0.02	-	-	-	-	-	0.02
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.22	\$0.15	\$0.10	\$0.05	\$0.07	\$(0.03)	\$0.54

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

Q2 2016 YTD GAAP EPS Reconciliation

Six Months Ended June 30, 2016	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2016 GAAP Earnings (Loss) Per Share	\$0.31	\$0.28	\$0.25	\$0.14	(\$0.28)	\$(0.23)	\$0.48
Mark-to-market impact of economic hedging activities	0.12	-	-	-	-	-	0.12
Unrealized gains related to NDT fund investments	(0.07)	-	-	-	-	-	(0.07)
Merger and integration costs	0.02	-	-	-	0.04	0.04	0.09
Merger commitments	-	-	-	-	0.30	0.12	0.43
Long-lived asset impairments	0.10	-	-	-	-	-	0.10
Plant retirements and divestitures	0.14	-	-	-	-	-	0.14
Reassessment of state deferred income taxes	0.01	-	-	-	-	(0.01)	-
Cost management program	0.02	-	-	-	-	-	0.02
CENG noncontrolling interest	0.02	-	-	-	-	-	0.02
2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.69	\$0.28	\$0.25	\$0.14	\$0.06	\$(0.08)	\$1.33

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

Q2 2017 YTD GAAP EPS Reconciliation (continued)

Six Months Ended June 30, 2017	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2017 GAAP Earnings (Loss) Per Share	\$0.19	\$0.28	\$0.23	\$0.18	\$0.22	\$0.06	\$1.15
Mark-to-market impact of economic hedging activities	0.15	-	-	-	-	-	0.15
Unrealized gains related to NDT fund investments	(0.15)	-	-	-	-	-	(0.15)
Amortization of commodity contract intangibles	0.02	-	-	-	-	-	0.02
Merger and integration costs	0.04	-	-	-	-	-	0.04
Merger commitments	(0.02)	-	-	-	(0.06)	(0.06)	(0.15)
Long-lived asset impairments	0.29	-	-	-	-	-	0.29
Plant retirements and divestitures	0.07	-	-	-	-	-	0.07
Reassessment of state deferred income taxes	-	-	-	-	-	(0.02)	(0.02)
Cost management program	0.01	-	-	-	-	-	0.01
Tax settlements	(0.01)	-	-	-	-	-	(0.01)
Bargain purchase gain	(0.24)	-	-	-	-	-	(0.24)
Like-kind exchange tax position	-	0.02	-	-	-	(0.05)	(0.03)
CENG noncontrolling interest	0.06	-	-	-	-	-	0.06
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.40	\$0.30	\$0.23	\$0.18	\$0.15	(\$0.08)	\$1.19

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

GAAP to Operating Adjustments

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

GAAP to Non-GAAP Reconciliations

YE 2017 Exelon FFO Calculation (\$M) ^(1,2)		YE 2017 Exelon Adjusted Debt Calculation (\$M) ^(1,2)	
GAAP Operating Income	\$3,450	Long-Term Debt (including current maturities)	\$32,025
Depreciation & Amortization	\$3,375	Short-Term Debt	\$1,225
EBITDA	\$6,825	+ PPA Imputed Debt ⁽⁵⁾	\$350
+/- Non-operating activities and nonrecurring items ⁽³⁾	\$550	+ Operating Lease Imputed Debt ⁽⁶⁾	\$875
- Interest Expense	(\$1,450)	+ Pension/OPEB Imputed Debt ⁽⁷⁾	\$3,450
+ Current Income Tax (Expense)/Benefit	\$25	- Off-Credit Treatment of Debt ⁽⁸⁾	(\$1,725)
+ Nuclear Fuel Amortization	\$1,075	- Surplus Cash Adjustment ⁽⁹⁾	(\$550)
+/- Other S&P Adjustments ⁽⁴⁾	\$375	+/- Other S&P Adjustments ⁽⁴⁾	\$275
= FFO (a)	\$7,400	= Adjusted Debt (b)	\$35,925

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

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

GAAP to Non-GAAP Reconciliations

YE 2017 ExGen Net Debt Calculation (\$M) ⁽¹⁾	
Long-Term Debt (including current maturities)	\$8,875
Short-Term Debt	\$375
- Surplus Cash Adjustment	<u>(\$300)</u>
= Net Debt (a)	\$8,950

YE 2017 ExGen Operating EBITDA Calculation (\$M) ⁽¹⁾	
GAAP Operating Income	\$775
Depreciation & Amortization	<u>\$1,400</u>
EBITDA	\$2,175
+/- Non-operating activities and nonrecurring items ⁽²⁾	<u>\$875</u>
= Operating EBITDA (b)	\$3,050

YE 2017 Book Debt / EBITDA	
Net Debt (a)	= 2.9x
Operating EBITDA (b)	

YE 2017 ExGen Net Debt Calculation (\$M) ⁽¹⁾	
Long-Term Debt (including current maturities)	\$8,875
Short-Term Debt	\$375
- Surplus Cash Adjustment	(\$300)
- Nonrecourse Debt	<u>(\$1,900)</u>
= Net Debt (a)	\$7,050

YE 2017 ExGen Operating EBITDA Calculation (\$M) ⁽¹⁾	
GAAP Operating Income	\$775
Depreciation & Amortization	<u>\$1,400</u>
EBITDA	\$2,175
+/- Non-operating activities and nonrecurring items ⁽²⁾	\$875
- EBITDA from projects financed by nonrecourse debt	<u>(\$250)</u>
= Operating EBITDA (b)	\$2,800

YE 2017 Recourse Debt / EBITDA	
Net Debt (a)	= 2.5x
Operating EBITDA (b)	

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

(2) Reflects impact of operating adjustments on GAAP EBITDA

GAAP to Non-GAAP Reconciliations

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

ExGen Adjusted O&M Reconciliation (\$M) ⁽²⁾	2017
GAAP O&M	\$6,300
Decommissioning ⁽³⁾	25
TMI Retirement	(100)
EGTP Impairment	(425)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses ⁽⁴⁾	(425)
O&M for managed plants that are partially owned	(425)
Other	(100)
Adjusted O&M (Non-GAAP)	\$4,850

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

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

(3) Reflects earnings neutral O&M

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

GAAP to Non-GAAP Reconciliations

2017 Adjusted Cash from Ops Calculation (\$M) ⁽¹⁾	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
Net cash flows provided by operating activities (GAAP)	\$1,150	\$750	\$700	\$1,150	\$3,450	(\$250)	\$6,975
Other cash from investing activities	-	-	-	-	(\$275)	-	(\$275)
Intercompany receivable adjustment	(\$350)	-	-	-	-	\$350	-
Counterparty collateral activity	-	-	-	-	\$225	-	\$225
Adjusted Cash Flow from Operations	\$800	\$750	\$700	\$1,150	\$3,425	\$100	\$6,950

2017 Cash From Financing Calculation (\$M) ⁽¹⁾	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	\$1,000	\$175	\$200	\$175	(\$275)	\$350	\$1,625
Dividends paid on common stock	\$425	\$300	\$200	\$325	\$650	(\$650)	\$1,250
Intercompany receivable adjustment	\$350	-	-	-	-	(\$350)	-
Financing Cash Flow	\$1,775	\$475	\$400	\$500	\$375	(\$650)	\$2,875

Exelon Total Cash Flow Reconciliation ⁽¹⁾	2017
GAAP Beginning Cash Balance	\$650
Adjustment for Cash Collateral Posted	<u>\$400</u>
Adjusted Beginning Cash Balance ⁽³⁾	\$1,050
Net Change in Cash (GAAP) ⁽²⁾	<u>\$375</u>
Adjusted Ending Cash Balance ⁽³⁾	\$1,425
Adjustment for Cash Collateral Posted	<u>(\$625)</u>
GAAP Ending Cash Balance	\$775

(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