

Earnings Conference Call Third Quarter 2019

October 31, 2019



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 2018 Annual Report on Form 10-K in (a) Part I, ITEM 1A. Risk Factors, (b) Part II, ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part II, ITEM 8. Financial Statements and Supplementary Data: Note 22, Commitments and Contingencies; (2) Exelon's Third Quarter 2019 Quarterly Report on Form 10-Q (to be filed on October 31, 2019) in (a) Part II, ITEM 1A. Risk Factors; (b) Part 1, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, ITEM 1. Financial Statements: Note 16, Commitments and Contingencies; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this presentation. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

Non-GAAP Financial Measures

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, asset impairments, certain amounts associated with plant retirements and divestitures, costs related to cost management programs, asset retirement obligations 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

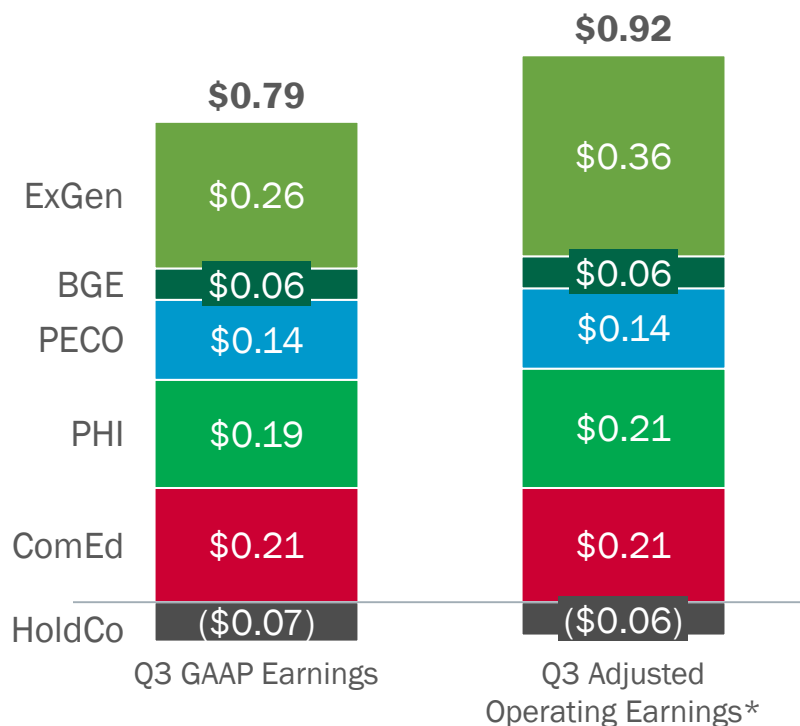
This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of Exelon's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business.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

Third Quarter Results

EPS Results



- GAAP earnings were \$0.79 per share in Q3 2019 vs. \$0.76 per share in Q3 2018
- Adjusted operating earnings* were \$0.92 per share in Q3 2019 vs. \$0.88 per share in Q3 2018, exceeding our guidance range of \$0.80-\$0.90 per share

Key Developments

- Named to Dow Jones Sustainability Index for 14th consecutive year
- Launched \$20 million Climate Change Investment Initiative
- Constructive final Order received in Pepco Maryland distribution rate case filing
- Maryland Public Service Commission approved the implementation of multi-year rate plans (PC 51)
- NY ZEC program upheld by New York State Supreme Court
- Pennsylvania intends to join the Regional Greenhouse Gas Initiative
- Reached agreement with Maryland which will allow for continued operation of Conowingo Dam
- Announcing an additional \$100M of cost savings

Note: Amounts may not sum due to rounding

Operating Highlights

Exelon Utilities Operational Metrics

Operations	Metric	YTD 2019			
		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	Gas Odor Response		No Gas Operations		

- ComEd continued its top decile performance in SAIFI
- Reliability metrics at our Mid-Atlantic utilities were challenged by an increased number of minor storms; plans to improve reliability have been implemented
- Each utility continued to deliver on key customer operations metrics:
 - BGE, ComEd and PHI achieved top decile performance in Abandon Rate, while ComEd and PHI continued to perform in the top decile in Service Level
 - BGE, ComEd and PECO recorded top decile performance in Customer Satisfaction
 - PECO and PHI performed in top decile in Gas Odor Response

Quartile

Q1	Q2
Q3	Q4

(1) 2.5 Beta SAIFI is YE projection

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

Exelon Generation Operational Performance

Exelon Nuclear Fleet⁽²⁾

- Best in class performance across our Nuclear fleet:
 - Q3 2019 Nuclear Capacity Factor: 95.5%
 - Owned and operated Q3 2019 production of 39.2 TWh



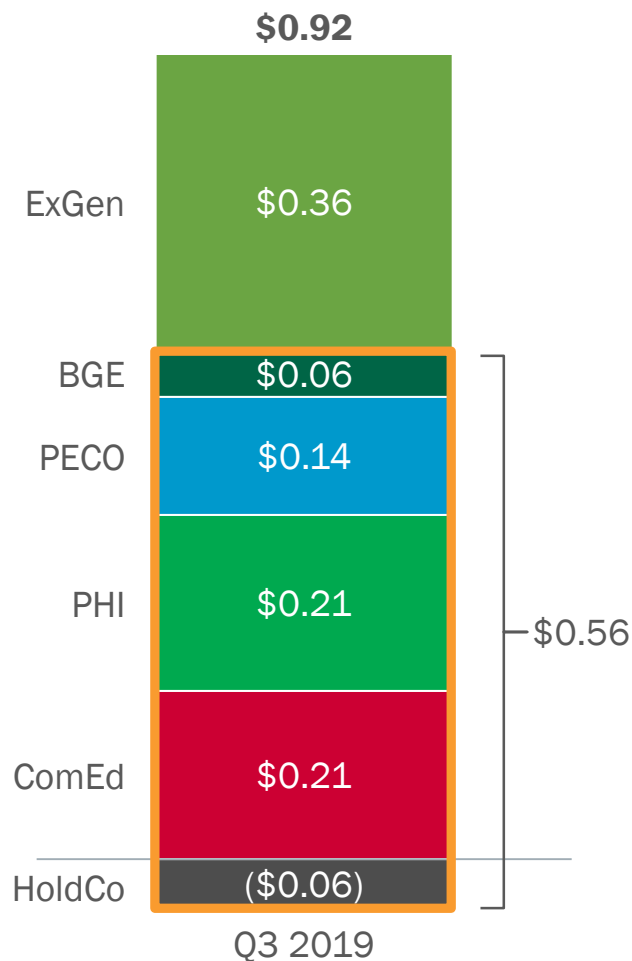
Fossil and Renewable Fleet

- Q3 2019 Power Dispatch Match: 97.5%
- Q3 2019 Renewables Energy Capture: 96.5%

Third Quarter Adjusted Operating Earnings* Drivers

Q3 2019 Adjusted Operating EPS* Results

Q3 2019 vs. Guidance of \$0.80 - \$0.90



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

Exelon Utilities

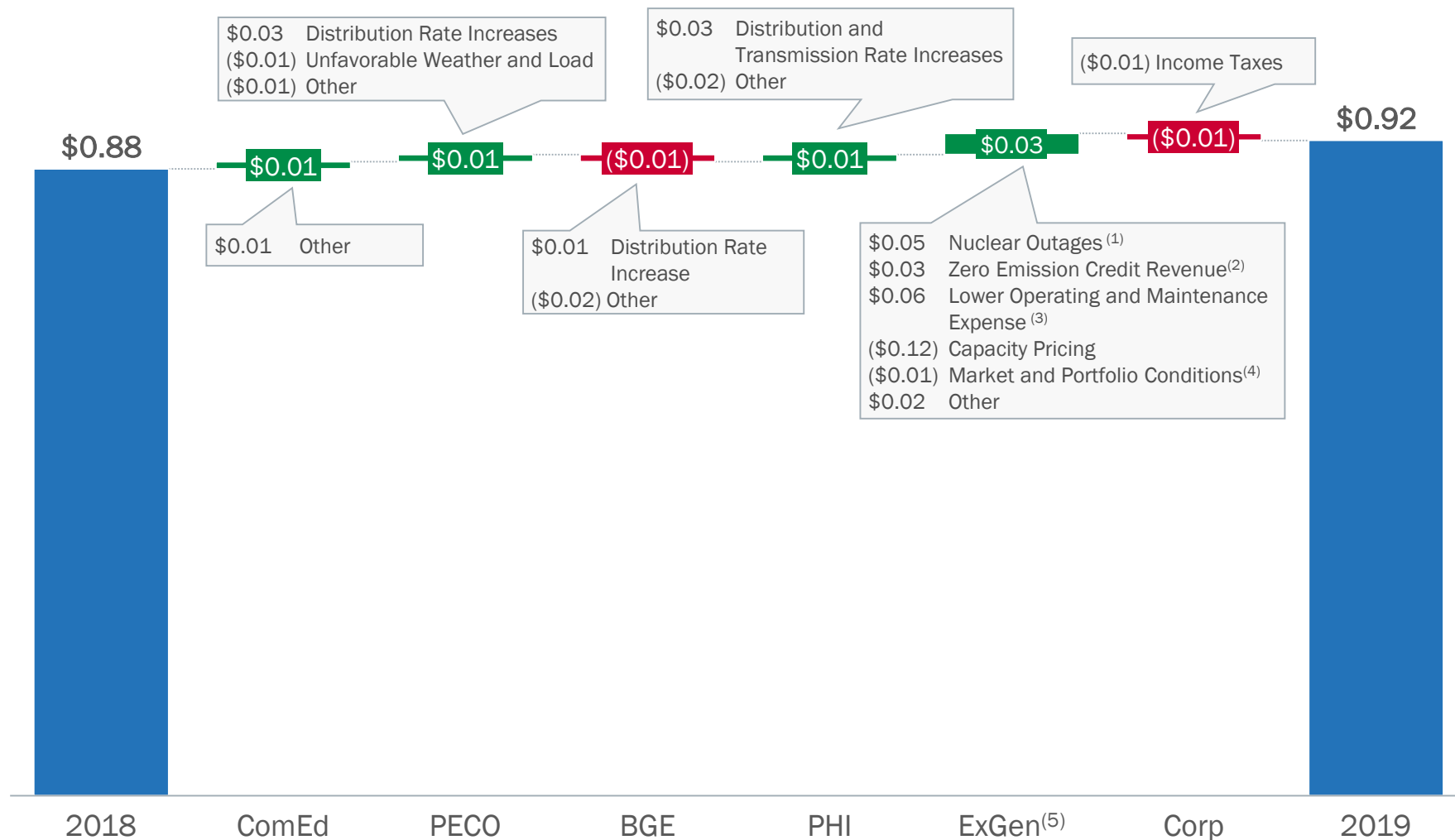
- ↑ Timing of O&M
- ↑ Favorable weather

Exelon Generation

- ↓ Owned and contracted assets in ERCOT and lower portfolio optimization

Note: Amounts may not sum due to rounding

Q3 2019 QTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

(1) Reflects the revenue and operating and maintenance expense impacts of lower nuclear outage days in 2019

(2) Primarily reflects an increase in New York ZEC prices and the approval of the New Jersey ZEC Program in the second quarter of 2019

(3) Includes the impacts of previous cost management programs and lower pension and OPEB costs

(4) Primarily reflects lower realized energy prices

(5) Drivers reflect CENG ownership at 100%

Narrowing 2019 Guidance Range

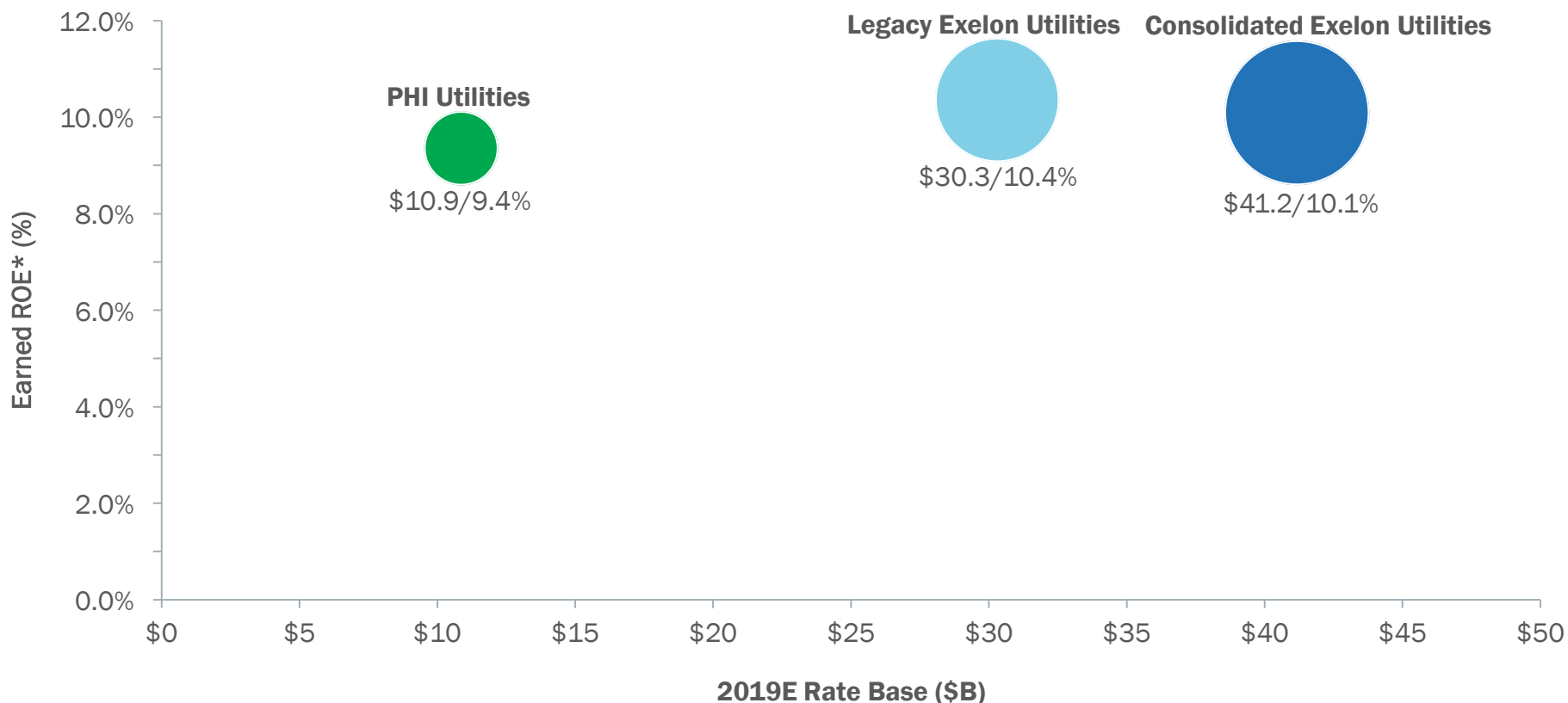


Note: Amounts may not sum due to rounding

(1) 2019 Adjusted Operating Earnings* Initial and Revised Guidance are based on expected average outstanding shares of 973M and 974M, respectively

Exelon Utilities Trailing Twelve Month Earned ROEs*

Q3 2019: Trailing Twelve Month Earned ROEs*



TTM ROEs*	PHI Utilities	Legacy Exelon Utilities	Consolidated Exelon Utilities
Q3 2019	9.4%	10.4%	10.1%
Q2 2019	9.1%	10.5%	10.2%

Note: Represents the twelve-month period ending September 30, 2019 and June 30, 2019. Earned ROEs* represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Electric Transmission). Size of bubble based on rate base.

Exelon Utilities' Distribution Rate Case Updates

Rate Case Schedule and Key Terms

	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Revenue Requirement	Requested ROE / Equity Ratio	Expected Order
Pepco MD Electric		FO											\$10.3M ⁽¹⁾	9.60% / 50.46%	Aug 12, 2019
ComEd	RT	EH	IB RB			FO							(\$16.9M) ^(1,2)	8.91% / 47.97%	Dec 4, 2019
BGE			IT	RT SA		FO							\$79.0M ^(1,4)	Elec: 9.70%; Gas: 9.75% / N/A ⁽³⁾	Dec 20, 2019
Pepco DC Electric								IT		RT		EH	\$160.0M ^(1,5) 3-Year MYP	10.30% / 50.68%	Q4 2020

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: Unless otherwise noted, based on schedules of Illinois Commerce Commission, Maryland Public Service Commission, Pennsylvania Public Utility Commission, Delaware Public Service Commission, Public Service Commission of the District of Columbia, and New Jersey Board of Public Utilities that are subject to change

- (1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings
- (2) Revenue requirement in initial filing was a decrease of (\$6.4M). Through the discovery period in the current proceeding, ComEd agreed to ~(\$10.5M) in adjustments to limit issues in the case.
- (3) Rate of Return and Return on Equity are used solely for AFUDC, surcharges and regulatory asset carrying charges and sets no precedent
- (4) Current revenue requirement reflects \$25.0M increase for electric and \$54.0M increase for gas. Increase reflects \$7.1M of ERI (electric) and \$8.7M of STRIDE (gas) that will be transferred from the ERI and STRIDE surcharges to base rates.
- (5) Reflects 3-year cumulative multi-year plan. Company proposed incremental revenue requirement increases of \$84M, \$40M and \$36M with rates effective November 1, 2020, January 1, 2021 and January 1, 2022, respectively.

Featured Utility Capital Investments

BGE's Key Crossing Reliability Initiative

- **Forecasted project cost:**
 - \$232 million
- **In service date:**
 - Overhead construction and removal of the existing underground circuit and terminal stations are expected to be completed by year-end 2023 (subject to regulatory approval)
- **Project scope:**
 - Installation of a double circuit, 230kV overhead electric transmission line across the Patapsco River, including eight utility monopoles and vessel collision protection barriers to prevent damage to critical infrastructure
 - Replaces the existing 2.25 mile underground circuit, which is a critical link to Baltimore's regional transmission system, transporting electricity in and out of BGE's service territory and supporting the area's growing energy demands
 - Improves grid reliability by reducing risk of power outages caused by aging infrastructure and supports faster restoration of customer interruptions



ACE's Lewis Higbee Ontario Rebuild Project

- **Forecasted project cost:**
 - \$62 million
- **In service date:**
 - Project to be completed in May 2020
- **Project scope:**
 - Upgrade of the existing Atlantic City transmission system, including rebuilding three 69kV transmission lines totaling ~16.5 line miles, 220 new galvanized steel utility poles and a 795 kcmil conductor
 - Addresses aging infrastructure that services 13,720 customers, including 52 high-profile businesses such as the AtlantiCare Regional Medical Center, the Municipal Utilities Authority, the Atlantic City Convention Center, and nine casinos
 - Improves transmission resiliency and reliability by replacing obsolete wood utility poles that are inadequate for wetland conditions and prone to damage from severe storms such as Super Storm Sandy



Exelon Generation: Gross Margin* Update

Gross Margin Category (\$M) ⁽¹⁾	September 30, 2019			Change from June 30, 2019		
	2019	2020	2021	2019	2020	2021
Open Gross Margin* ^(2,5) (including South, West, New England, Canada hedged gross margin)	\$3,800	\$4,000	\$3,550	\$200	\$450	\$250
Capacity and ZEC Revenues ^(2,5)	\$2,050	\$1,900	\$1,850	-	-	-
Mark-to-Market of Hedges ^(2,3)	\$1,150	\$400	\$250	\$(100)	\$(350)	\$(150)
Power New Business / To Go	\$150	\$500	\$750	\$(100)	\$(100)	\$(50)
Non-Power Margins Executed	\$400	\$250	\$150	\$50	\$50	-
Non-Power New Business / To Go	\$100	\$250	\$350	\$(50)	\$(50)	\$(50)
Total Gross Margin*^(4,5)	\$7,650	\$7,300	\$6,900	-	-	-

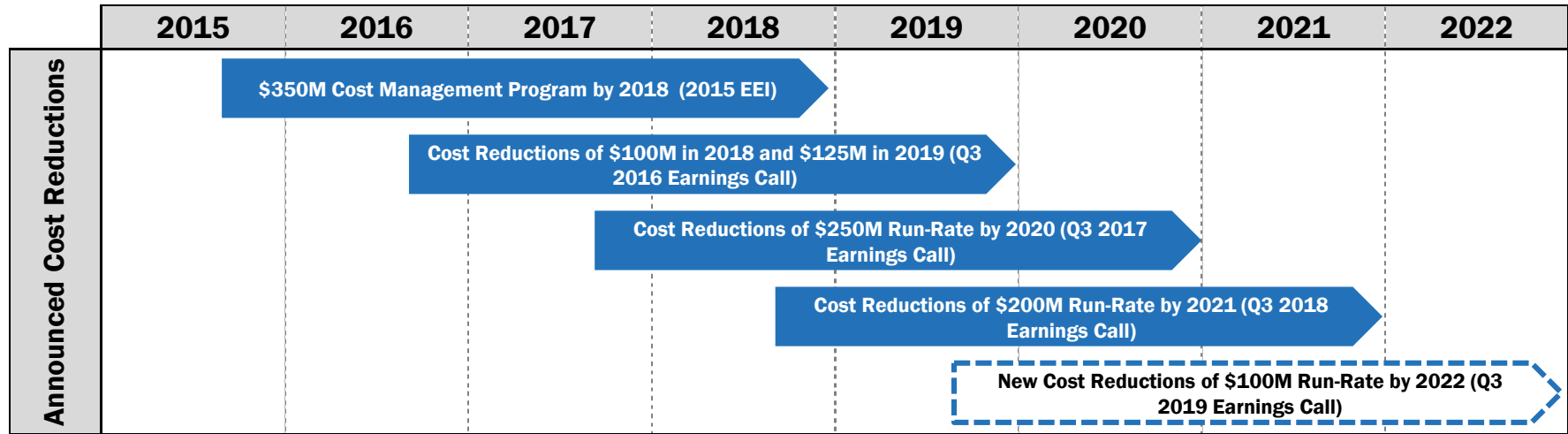
Recent Developments

- 2019 Total Gross Margin* is flat due to increased power prices offset by our hedges and execution of a combined \$150M of power and non-power new business
- 2020 and 2021 Total Gross Margins* are flat due to increased power prices, offset by our hedges and new business target reductions; executed a combined \$100M of power and non-power new business in 2020
- The combined \$50M and \$100M power and non-power new business target reductions in 2020 and 2021, respectively, are due to decreased optimization opportunities from a low price and low volatility market
- Behind ratable hedging position reflects the fundamental upside we see in power prices
 - ~5-8% behind ratable in 2020 when considering cross commodity hedges
 - ~1-4% behind ratable in 2021 when considering cross commodity hedges

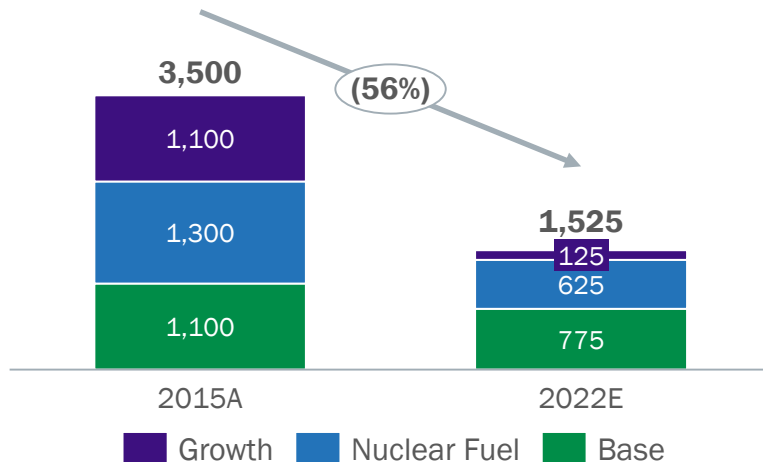
(1) Gross margin* categories rounded to nearest \$50M
 (2) Excludes EDF's equity ownership share of the CENG Joint Venture
 (3) Mark-to-Market of Hedges assumes mid-point of hedge percentages
 (4) Based on September 30, 2019 market conditions
 (5) Reflects TMI retirement in September 2019

Exelon is Committed to Managing its Costs

Since 2015 Exelon has announced more than \$1B of cost reductions



ExGen CapEx (\$M)⁽¹⁾



Key Commentary

- We are looking at all aspects of the ExGen business to find efficiencies and reduce costs
- Since 2015 we have reduced costs by more than ~\$1B and CapEx by more than 50%
- Committing to **\$100M** in additional run-rate cost reductions at ExGen by 2022
 - \$75M of O&M savings
 - \$25M of other P&L savings

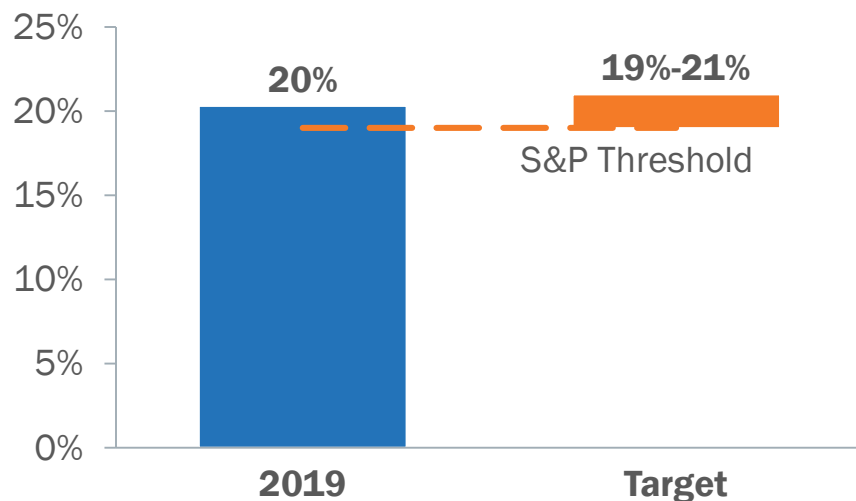
(1) Capital spend represents cash CapEx with CENG at 100% and excludes merger commitments. Base and Growth figures as disclosed in 2016 Analyst Day deck and Nuclear Fuel as disclosed in the 2015 EEI deck.

Maintaining Strong Investment Grade Credit Ratings is a Top Financial Priority

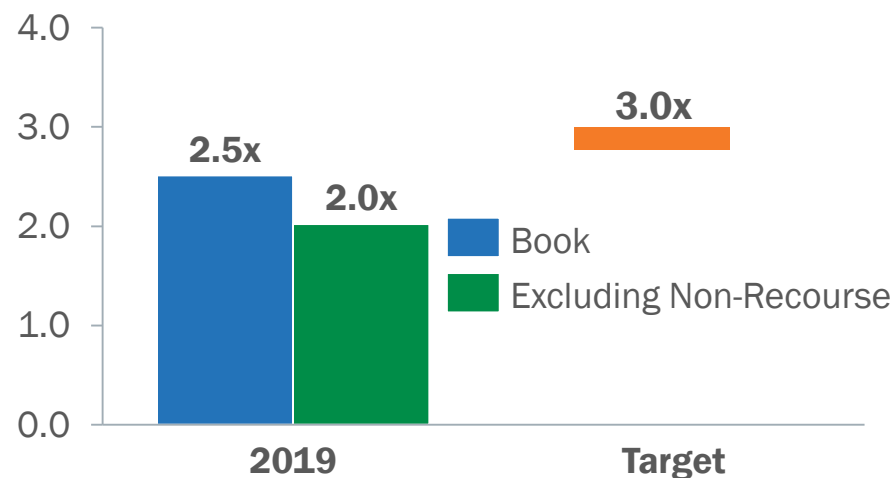
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Exelon S&P FFO/Debt %^{*(1,2)}



ExGen Debt/EBITDA Ratio^{*(4)}



Credit Ratings by Operating Company

Current Ratings ⁽³⁾	ExCorp	ExGen	ComEd	PECO	BGE	ACE	DPL	Pepco
Moody's	Baa2	Baa2	A1	Aa3	A3	A2	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) Exelon Corp downgrade threshold (orange dotted line) is based on the S&P Exelon Corp Summary Report; represents minimum level to maintain current Issuer Credit Rating at Exelon Corp

(3) Current senior unsecured ratings as of September 30, 2019, for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco

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

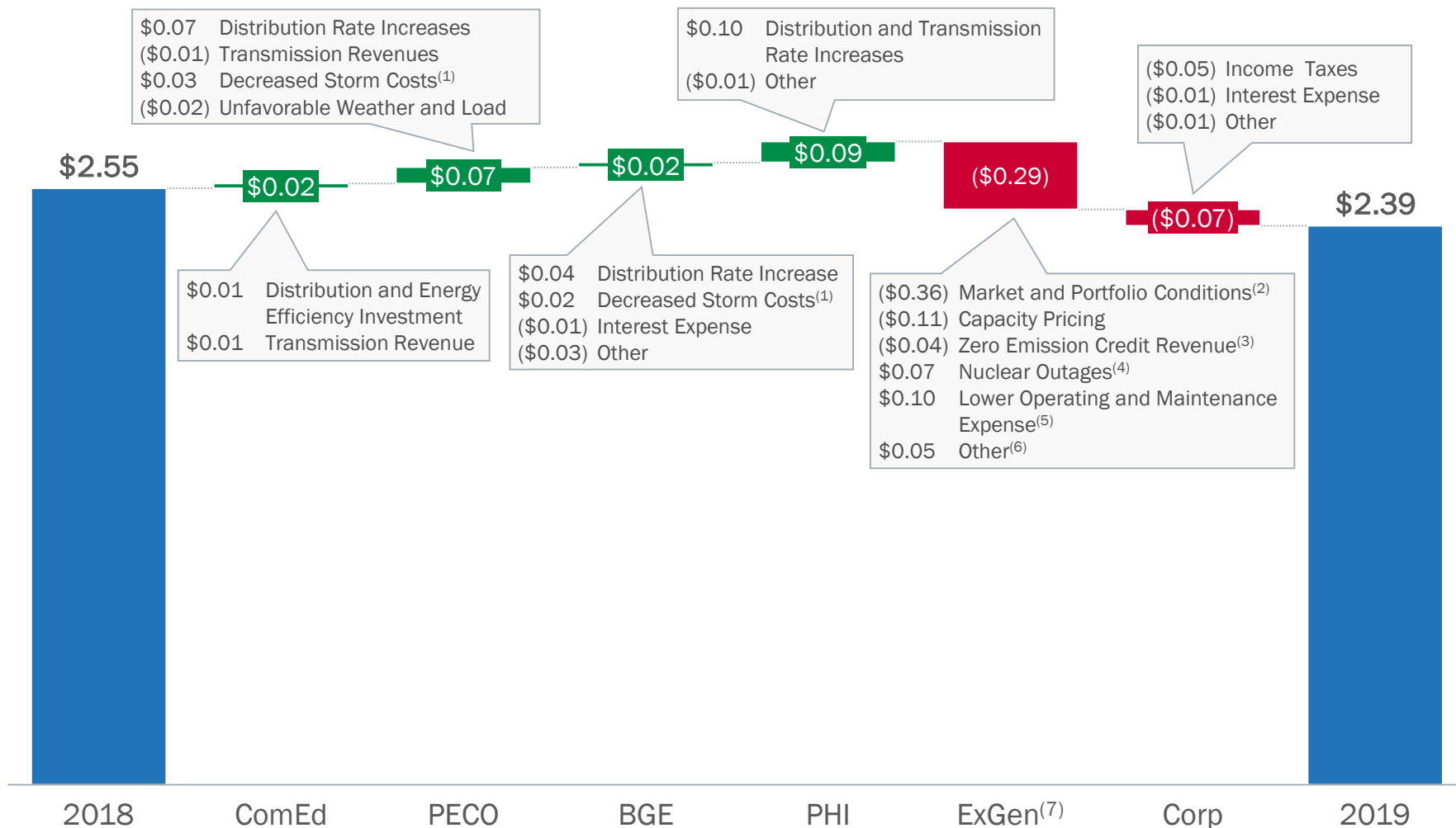
The Exelon Value Proposition

- **Regulated Utility Growth** with utility EPS rising 6-8% annually from 2018-2022 and rate base growth of 7.8%, representing an expanding majority of earnings
- **ExGen's strong free cash generation** will provide ~\$4.2B for utility growth and reduce debt by ~\$2.5B 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 2022 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

Q3 2019 YTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

(1) Primarily reflects the absence of the March 2018 winter storms.

(2) Primarily reflects lower realized energy prices

(3) Primarily reflects the absence of revenue recognized in the first quarter 2018 related to zero emissions credits generated in Illinois from June through December 2017, partially offset by an increase in New York ZEC prices and the approval of the New Jersey ZEC Program in the second quarter of 2019

(4) Reflects the revenue and operating and maintenance impacts of lower nuclear outage days in 2019, excluding Salem, partially offset by the impacts of higher nuclear outage days at Salem in 2019

(5) Includes the impacts of previous cost management programs and lower pension and OPEB costs

(6) Primarily reflects the elimination of activity attributable to noncontrolling interest, primarily for CENG, partially offset by lower realized NDT fund gains

(7) Drivers reflect CENG ownership at 100%

2019 Projected Sources and Uses of Cash

(\$M) ⁽¹⁾	BGE	ComEd	PECO	PHI	Total Utilities	ExGen	Corp ⁽⁸⁾	Exelon	Cash Balance	
Beginning Cash Balance⁽²⁾									1,825	
Adjusted Cash Flow from Operations ⁽²⁾	750	1,375	775	1,025	3,925	3,800	(350)	7,350		
Base CapEx and Nuclear Fuel ⁽³⁾	-	-	-	-	-	(1,775)	(75)	(1,825)		
Free Cash Flow*	750	1,375	775	1,025	3,925	2,025	(425)	5,525		
Debt Issuances	400	700	325	375	1,800	-	-	1,800		
Debt Retirements	-	(300)	-	-	(300)	(625)	-	(925)		
Project Financing	n/a	n/a	n/a	n/a	n/a	(100)	n/a	(100)		
Equity Issuance/Share Buyback	-	-	-	-	-	-	-	-		
Contribution from Parent	200	250	175	175	800	-	(800)	-		
Other Financing ⁽⁴⁾	75	250	-	50	400	(125)	150	450		
Financing*⁽⁵⁾	675	900	500	625	2,700	(850)	(650)	1,200		
Total Free Cash Flow and Financing	1,425	2,275	1,275	1,650	6,625	1,175	(1,075)	6,725		
Utility Investment	(1,175)	(1,875)	(1,000)	(1,400)	(5,450)	-	-	(5,450)		
ExGen Growth ^(3,6)	-	-	-	-	-	(125)	-	(125)		
Acquisitions and Divestitures	-	-	-	-	-	50	-	50		
Equity Investments	-	-	-	-	-	(25)	-	(25)		
Dividend ⁽⁷⁾	-	-	-	-	-	-	-	(1,400)		
Other CapEx and Dividend	(1,175)	(1,875)	(1,000)	(1,400)	(5,450)	(100)	-	(6,975)		
Total Cash Flow*	250	375	275	250	1,175	1,075	(1,075)	(250)		
Ending Cash Balance⁽²⁾									1,575	

(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, tax sharing from the parent, renewable JV distributions, tax equity cash flows, EDF Tax distributions and capital leases

(5) Financing cash flow* excludes intercompany dividends

(6) ExGen Growth CapEx primarily includes Retail Solar and W. Medway

(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 \$5,525M of free cash flow*, including \$2,025M at ExGen and \$3,925M at the Utilities

Supported by a strong balance sheet

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

- ✓ \$1,500M of long-term debt at the utilities, net of refinancing, to support continued growth and retirement of \$725M of ExGen debt

Enable growth & value creation

Creating value for customers, communities and shareholders

- ✓ Investing \$5,575M of growth CapEx, with \$5,450M at the Utilities and \$125M at ExGen

Note: Amounts may not sum due to rounding

Exelon Utilities

Pepco MD (Electric) Distribution Rate Case Filing

Rate Case Filing Details		Notes
Case No.	9602	<ul style="list-style-type: none"> Pepco MD filed an application with the Maryland Public Service Commission (MDPSC) on January 15, 2019, 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 On July 9, the CPULJ issued the proposed order with the final MDPSC order issued on August 12
Test Year	February 1, 2018 – January 31, 2019	
Test Period	12 months actual	
Common Equity Ratio	50.46%	
Rate of Return	ROE: 9.60%; ROR: 7.45%	
Rate Base (Adjusted)	\$2.0B	
Revenue Requirement Increase	\$10.3M ⁽¹⁾	
Residential Total Bill % Increase	1.40%	

Detailed Rate Case Schedule

	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
Filed rate case		▲ 1/15/2019										
Intervenor testimony					▲ 4/12/2019							
Rebuttal testimony						▲ 4/30/2019						
Evidentiary hearings						■ 5/21/2019 - 5/24/2019						
Initial briefs							▲ 6/17/2019					
Commission order									▲ 8/12/2019			

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

ComEd Distribution Rate Case Filing

Rate Case Filing Details		Notes
Docket No.	19-0387	<ul style="list-style-type: none"> April 8, 2019, ComEd filed its annual distribution formula rate update with the Illinois Commerce Commission seeking a decrease to distribution base rates October 23, 2019, ComEd received the ALJ proposed order. No additional adjustments to the revenue requirement were recommended. The Final Order from the Commission is expected on December 4, 2019.
Test Year	January 1, 2018 – December 31, 2018	
Test Period	2018 Actual Costs + 2019 Projected Plant Additions	
Proposed Common Equity Ratio	47.97%	
Proposed Rate of Return	ROE: 8.91%; ROR: 6.51%	
Proposed Rate Base (Adjusted)	\$11,355M	
Requested Revenue Requirement Decrease	(\$16.9M) ^(1,2)	
Residential Total Bill % Decrease	(0.7%)	

Detailed Rate Case Schedule

	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Filed rate case		▲ 4/8/2019										
Intervenor testimony				▲ 6/20/2019								
Rebuttal testimony					▲ 7/17/2019							
Evidentiary hearings						▲ 8/29/2019						
Initial briefs							▲ 9/12/2019					
Reply briefs								▲ 9/26/2019				
Commission order expected										▲ 12/4/2019		

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

(2) Revenue requirement in initial filing was a decrease of (\$6.4M). Through the discovery period in the current proceeding, ComEd agreed to ~(\$10.5M) in adjustments to limit issues in the case.

BGE Distribution Rate Case Filing

Rate Case Filing Details		Notes
Docket No.	Case No. 9610	<ul style="list-style-type: none"> Case originally filed on May 24, 2019 seeking an increase in electric and gas distribution revenues October 25, 2019, BGE filed a settlement agreement with the MDPSC. The black box agreement does not stipulate the Capital structure or Rate Base. MDPSC scheduled hearings for November 14 & 15, 2019 The Commission is expected to issue an order on this case on or before December 20, 2019
Test Year	August 1, 2018 – July 31, 2019	
Test Period	8 months actual + 4 months estimated	
Proposed Common Equity Ratio	N/A	
Proposed Rate of Return⁽²⁾	Electric [ROE: 9.70%; ROR: 6.94%] Gas [ROE: 9.75%; ROR: 6.97%]	
Proposed Rate Base (Adjusted)	N/A	
Requested Revenue Requirement Increase	\$79.0M ^(1,3)	
Residential Total Bill % Increase	~2.9% ⁽⁴⁾	

Detailed Rate Case Schedule

	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr
Filed rate case	▲ 5/24/2019											
Intervenor testimony					▲ 9/10/2019							
Rebuttal testimony						▲ 10/4/2019						
Settlement Agreement							▲ 10/25/2019					
Commission order expected by								▲ 12/20/2019				

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

(2) Rate of Return and Return on Equity are used solely for AFUDC, surcharges and regulatory asset carrying charges and sets no precedent


(3) Current revenue requirement reflects \$25.0M increase for electric and \$54.0M increase for gas. Increase reflects \$7.1M of ERI (electric) and \$8.7M of STRIDE (gas) that will be transferred from the ERI and STRIDE surcharges to base rates.

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

Pepco DC (Electric) Distribution Rate Case Filing

Multi-Year Plan Case Filing Details		Notes
Formal Case No.	1156	<ul style="list-style-type: none"> May 30, 2019, Pepco DC filed a three year multi-year plan (MYP) request with the Public Service Commission of the District of Columbia (DCPSC) 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 MYP proposes five Performance Incentive Mechanisms (PIMs) focused on system reliability, customer service and interconnection Distributed Energy Resources (DER)
Test Year	January 1 – December 31	
Test Period	2020, 2021, 2022	
Proposed Common Equity Ratio	50.68%	
Proposed Rate of Return	ROE: 10.30%; ROR: 7.69%	
2020-2022 Proposed Rate Base (Adjusted)	\$2.2B, \$2.4B, \$2.6B	
2020-2022 Requested Revenue Requirement Increase ^(1,2)	\$84M, \$40M, \$36M	
2020-2022 Residential Total Bill % Increase ⁽²⁾	7.0%, 4.2%, 3.7%	

Detailed Rate Case Schedule

	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Filed rate case	▲ 5/30/2019																			
Intervenor testimony	▲ 2/19/2020																			
Rebuttal testimony	▲ 4/8/2020																			
Evidentiary hearings	■ 6/29/2020 - 7/3/2020																			
Initial briefs	▲ 8/26/2020																			
Reply briefs	▲ 9/10/2020																			
Commission order expected	Q4 2020 																			

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

(2) Company proposed incremental revenue requirement increases with rates effective November 1, 2020, January 1, 2021 and January 1, 2022, respectively.

Exelon Generation Disclosures

September 30, 2019

Portfolio Management Strategy

Strategic Policy Alignment

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

Three-Year Ratable Hedging

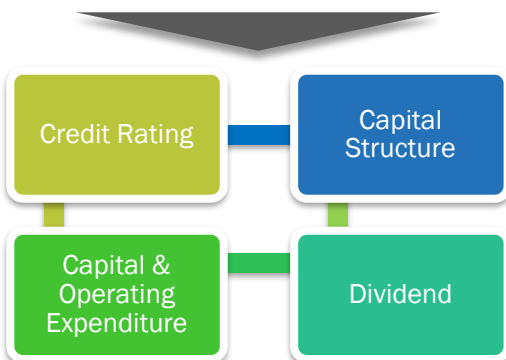
- Ensure stability in near-term cash flows and earnings
- Disciplined approach to hedging
- Tenor aligns with customer preferences and market liquidity
- Multiple channels to market that allow us to maximize margins
- Large open position in outer years to benefit from price upside

Bull / Bear Program

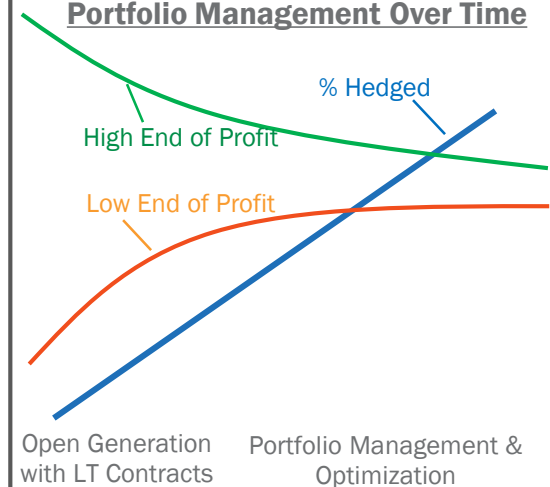
- Ability to exercise fundamental market views to create value within the ratable framework
- Modified timing of hedges versus purely ratable
- Cross-commodity hedging (heat rate positions, options, etc.)
- Delivery locations, regional and zonal spread relationships

Align Hedging & Financials

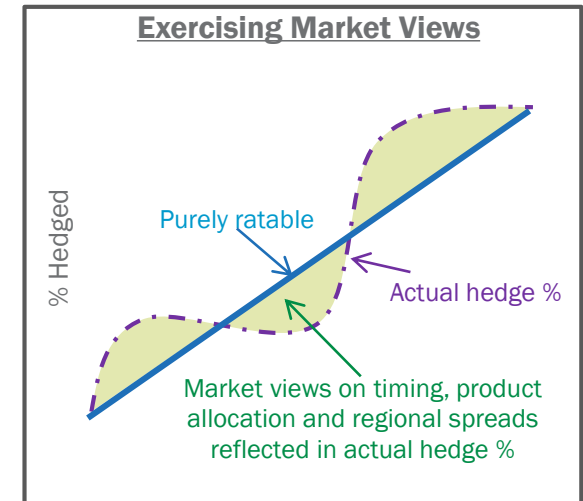
Establishing Minimum Hedge Targets



Portfolio Management Over Time



Exercising Market Views



Protect Balance Sheet

Ensure Earnings Stability

Create Value

Components of Gross Margin* Categories

Gross margin* linked to power production and sales

Open Gross Margin*

- Generation Gross Margin* at current market prices, including ancillary revenues, nuclear fuel amortization and fuels expense
- Power Purchase Agreement (PPA) Costs and Revenues
- Provided at a consolidated level for all regions (includes hedged gross margin* for South, West, New England 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 four major regions. Provided indirectly for each of the four major regions via Effective Realized Energy Price (ERP), 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, New England & Canada region will be included with Open Gross Margin; no expected generation, hedge %, ERP or reference prices provided for this region
- (2) MtM of hedges provided directly for the four larger regions; MtM of hedges is not provided directly at the regional level but can be easily estimated using ERP, 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, New England & Canada regions and optimization of fuel and PPA activities captured in Open Gross Margin*

ExGen Disclosures

Gross Margin Category (\$M) ⁽¹⁾	September 30, 2019		
	2019	2020	2021
Open Gross Margin (including South, West, New England & Canada hedged GM) ^(2,5)	\$3,800	\$4,000	\$3,550
Capacity and ZEC Revenues ^(2,5)	\$2,050	\$1,900	\$1,850
Mark-to-Market of Hedges ^(2,3)	\$1,150	\$400	\$250
Power New Business / To Go	\$150	\$500	\$750
Non-Power Margins Executed	\$400	\$250	\$150
Non-Power New Business / To Go	\$100	\$250	\$350
Total Gross Margin*^(4,5)	\$7,650	\$7,300	\$6,900

Reference Prices ⁽⁴⁾	2019	2020	2021
Henry Hub Natural Gas (\$/MMBtu)	\$2.61	\$2.42	\$2.45
Midwest: NiHub ATC prices (\$/MWh)	\$23.86	\$24.41	\$23.36
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$26.88	\$29.41	\$28.27
ERCOT-N ATC Spark Spread (\$/MWh)	\$15.67	\$13.78	\$9.48
HSC Gas, 7.2HR, \$2.50 VOM			
New York: NY Zone A (\$/MWh)	\$25.79	\$27.63	\$27.60

- (1) Gross margin* categories rounded to nearest \$50M
(2) Excludes EDF's equity ownership share of the CENG Joint Venture
(3) Mark-to-Market of Hedges assumes mid-point of hedge percentages
(4) Based on September 30, 2019 market conditions
(5) Reflects TMI retirement in September 2019

ExGen Disclosures

September 30, 2019

Generation and Hedges	2019	2020	2021
Exp. Gen (GWh)⁽¹⁾	188,200	185,700	181,600
Midwest	97,500	96,500	95,600
Mid-Atlantic ^(2,6)	54,100	47,600	48,300
ERCOT	19,900	25,900	21,100
New York ⁽²⁾	16,700	15,700	16,600
% of Expected Generation Hedged⁽³⁾	96%-99%	84%-87%	54%-57%
Midwest	97%-100%	85%-88%	53%-56%
Mid-Atlantic ^(2,6)	96%-99%	90%-93%	60%-63%
ERCOT	92%-95%	72%-75%	50%-53%
New York ⁽²⁾	95%-98%	80%-83%	46%-49%
Effective Realized Energy Price (\$/MWh)⁽⁴⁾			
Midwest	\$29.50	\$27.50	\$26.50
Mid-Atlantic ^(2,6)	\$39.00	\$36.00	\$32.00
ERCOT ⁽⁵⁾	\$4.50	\$4.00	\$7.50
New York ⁽²⁾	\$34.50	\$33.00	\$26.00

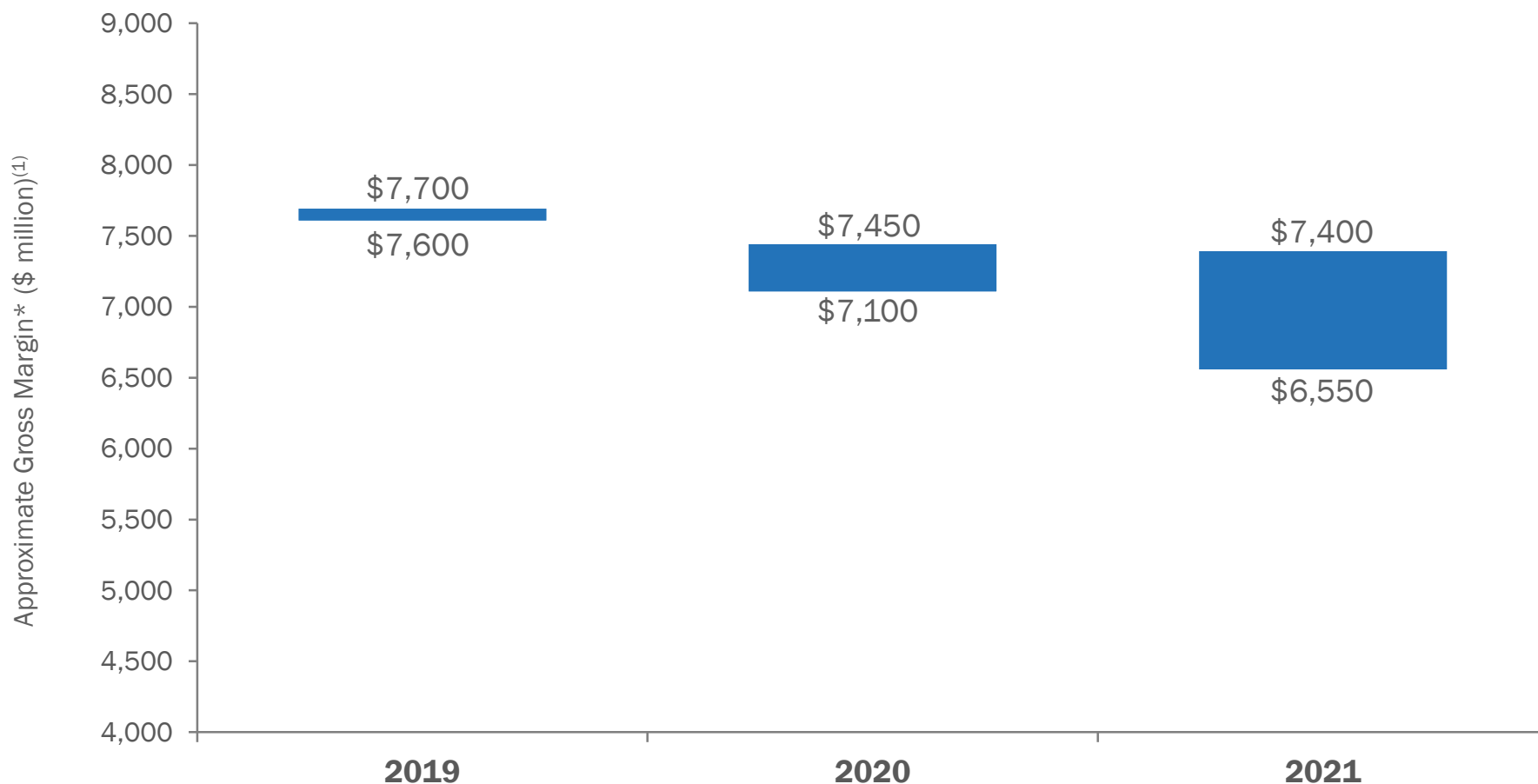
- (1) Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 11 refueling outages in 2019, 14 in 2020, and 13 in 2021 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 95.4%, 93.9%, and 94.2% in 2019, 2020, and 2021, respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2020 and 2021 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
- (6) Reflects TMI retirement in September 2019

ExGen Hedged Gross Margin* Sensitivities

Gross Margin* Sensitivities (with existing hedges) ⁽¹⁾	2019	2020	2021
Henry Hub Natural Gas (\$/MMBtu)			
+ \$1/MMBtu	-	\$155	\$465
- \$1/MMBtu	\$(10)	\$(150)	\$(440)
NiHub ATC Energy Price			
+ \$5/MWh	-	\$50	\$210
- \$5/MWh	-	\$(50)	\$(210)
PJM-W ATC Energy Price			
+ \$5/MWh	-	\$10	\$80
- \$5/MWh	-	\$(15)	\$(100)
NYPP Zone A ATC Energy Price			
+ \$5/MWh	-	\$10	\$40
- \$5/MWh	\$(5)	\$(10)	\$(40)
Nuclear Capacity Factor			
+/- 1%	+/- \$15	+/- \$30	+/- \$30

(1) Based on September 30, 2019 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 2020 and 2021 do not represent earnings guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years; the price distributions that generate this range are calibrated to market quotes for power, fuel, load following products, and options as of September 30, 2019. Gross Margin* Upside/Risk based on commodity exposure which includes open generation and all committed transactions. Reflects TMI retirement in September 2019.

Illustrative Example of Modeling Exelon Generation 2020 Total Gross Margin*

ZECJ-FIN-21

PUBLIC

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	South, West, NE & Canada
(A)	Start with fleet-wide open gross margin*	←————→		\$4 billion	————→	
(B)	Capacity and ZEC	←————→		\$1.9 billion	————→	
(C)	Expected Generation (TWh)	96.5	47.6	25.9	15.7	
(D)	Hedge % (assuming mid-point of range)	86.5%	91.5%	73.5%	81.5%	
(E=C*D)	Hedged Volume (TWh)	83.5	43.6	19.0	12.8	
(F)	Effective Realized Energy Price (\$/MWh)	\$27.50	\$36.00	\$4.00	\$33.00	
(G)	Reference Price (\$/MWh)	\$24.41	\$29.41	\$13.78	\$27.63	
(H=F-G)	Difference (\$/MWh)	\$3.09	\$6.59	(\$9.78)	\$5.37	
(I=E*H)	Mark-to-Market value of hedges (\$ million) ⁽¹⁾	\$255	\$285	(\$185)	\$65	
(J=A+B+I)	Hedged Gross Margin* (\$ million)			\$6,300		
(K)	Power New Business / To Go (\$ million)			\$500		
(L)	Non-Power Margins Executed (\$ million)			\$250		
(M)	Non-Power New Business / To Go (\$ million)			\$250		
(N=J+K+L+M)	Total Gross Margin*			\$7,300 million		

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

Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in \$M)⁽¹⁾	2019	2020	2021
Revenue Net of Purchased Power and Fuel Expense^{*(2,3)}	\$8,075	\$7,725	\$7,375
Other Revenues ⁽⁴⁾	\$(150)	\$(200)	\$(200)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses	\$(275)	\$(225)	\$(275)
Total Gross Margin* (Non-GAAP)	\$7,650	\$7,300	\$6,900

Key ExGen Modeling Inputs (in \$M)^(1,5)	2019
Other ⁽⁶⁾	\$125
Adjusted O&M ^{*(7)}	\$(4,325)
Taxes Other Than Income (TOTI) ⁽⁸⁾	\$(400)
Depreciation & Amortization ^{*(9)}	\$(1,125)
Interest Expense	\$(400)
Effective Tax Rate	21.0%

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

(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) Adjusted O&M* includes \$200M of non-cash expense related to the increase in the ARO liability due to the passage of time

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

(9) 2020 Depreciation & Amortization is favorable to 2019 by \$50M, while 2021 Depreciation & Amortization is favorable to 2019 by \$25M

Appendix

Reconciliation of Non-GAAP Measures

Q3 QTD GAAP EPS Reconciliation

Three Months Ended September 30, 2019	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
2019 GAAP Earnings (Loss) Per Share	\$0.21	\$0.14	\$0.06	\$0.19	\$0.26	(\$0.07)	\$0.79
Mark-to-market impact of economic hedging activities	-	-	-	-	(0.01)	0.01	-
Unrealized gains related to NDT funds	-	-	-	-	(0.04)	-	(0.04)
Asset Impairments	-	-	-	-	0.12	-	0.12
Plant retirements and divestitures	-	-	-	-	0.12	-	0.12
Cost management program	-	-	-	-	0.01	-	0.01
Asset retirement obligation	-	-	-	-	(0.09)	-	(0.09)
Change in environmental liabilities	-	-	-	0.02	-	-	0.02
Income Tax-Related Adjustments	-	-	-	-	0.01	-	0.01
Noncontrolling interests	-	-	-	-	(0.02)	-	(0.02)
2019 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.21	\$0.14	\$0.06	\$0.21	\$0.36	(\$0.06)	\$0.92

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

Q3 QTD GAAP EPS Reconciliation (continued)

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

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

Q3 YTD GAAP EPS Reconciliation

Nine Months Ended September 30, 2019	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
2019 GAAP Earnings (Loss) Per Share	\$0.56	\$0.42	\$0.27	\$0.42	\$0.75	(\$0.20)	\$2.22
Mark-to-market impact of economic hedging activities	-	-	-	-	0.08	0.02	0.10
Unrealized gains related to NDT funds	-	-	-	-	(0.19)	-	(0.19)
Asset Impairments	-	-	-	-	0.12	-	0.12
Plant retirements and divestitures	-	-	-	-	0.12	-	0.12
Cost management program	-	-	-	-	0.02	-	0.03
Litigation settlement gain	-	-	-	-	(0.02)	-	(0.02)
Asset retirement obligation	-	-	-	-	(0.09)	-	(0.09)
Change in environmental liabilities	-	-	-	0.02	-	-	0.02
Income Tax-Related Adjustments	-	-	-	-	0.01	-	0.01
Noncontrolling interests	-	-	-	-	0.06	-	0.06
2019 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.56	\$0.42	\$0.27	\$0.45	\$0.87	(\$0.18)	\$2.39

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

Q3 YTD GAAP EPS Reconciliation (continued)

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

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

Projected GAAP to Operating Adjustments

- **Exelon's projected 2019 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 funds to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements;
 - Asset impairments;
 - Impacts related to early plant retirements and divestitures;
 - Certain costs incurred to achieve cost management program savings;
 - Asset retirement obligations;
 - Other unusual items; and
 - Generation's noncontrolling interest related to CENG exclusion items.

GAAP to Non-GAAP Reconciliations⁽¹⁾

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

Exelon FFO Calculation⁽²⁾

GAAP Operating Income
 + Depreciation & Amortization
 = EBITDA
 - Interest Expense
 +/- Cash Taxes
 + Nuclear Fuel Amortization
 +/- Mark-to-Market Adjustments (Economic Hedges)
 +/- Other S&P Adjustments
 = **FFO (a)**

Exelon Adjusted Debt Calculation⁽¹⁾

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

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

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

GAAP to Non-GAAP Reconciliations⁽¹⁾

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

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

ExGen Net Debt Calculation

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

ExGen Net Debt Calculation Excluding Non-Recourse

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

ExGen Operating EBITDA Calculation

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

ExGen Operating EBITDA Calculation Excluding Non-Recourse

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

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

GAAP to Non-GAAP Reconciliations

Q3 2019 Operating TTM ROE Reconciliation (\$M)	PHI Utilities	Legacy EXC Utilities	Consolidated EU
Net Income (GAAP)	\$485	\$1,551	\$2,036
Operating Exclusions	\$27	\$6	\$33
Adjusted Operating Earnings	\$512	\$1,557	\$2,070
Average Equity	\$5,477	\$15,034	\$20,511
Operating TTM ROE (Adjusted Operating Earnings/Average Equity) (Non-GAAP)	9.4%	10.4%	10.1%

Q2 2019 Operating TTM ROE Reconciliation (\$M)	PHI Utilities	Legacy EXC Utilities	Consolidated EU
Net Income (GAAP)	\$473	\$1,539	\$2,012
Operating Exclusions	\$25	\$6	\$31
Adjusted Operating Earnings	\$499	\$1,545	\$2,043
Average Equity	\$5,457	\$14,665	\$20,122
Operating TTM ROE (Adjusted Operating Earnings/Average Equity) (Non-GAAP)	9.1%	10.5%	10.2%

ExGen Adjusted O&M Reconciliation (\$M) ⁽¹⁾	2019
GAAP O&M	\$4,875
Decommissioning ⁽²⁾	200
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses ⁽³⁾	(250)
O&M for managed plants that are partially owned	(400)
Other	(125)
Adjusted O&M (Non-GAAP)	\$4,325

Note: Amounts may not sum due to rounding

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

(2) Reflects asset retirement obligation update and earnings neutral O&M

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

GAAP to Non-GAAP Reconciliations

2019 Adjusted Cash from Ops Calculation (\$M) ⁽¹⁾	BGE	ComEd	PECO	PHI	ExGen	Other	Exelon
Net cash flows provided by operating activities (GAAP)	\$750	\$1,375	\$775	\$1,025	\$3,675	(\$350)	\$7,250
Other cash from investing activities	-	-	-	-	(\$275)	-	(\$275)
Counterparty collateral activity	-	-	-	-	\$400	-	\$400
Adjusted Cash Flow from Operations (Non-GAAP)	\$750	\$1,375	\$775	\$1,025	\$3,800	(\$350)	\$7,350

2019 Cash From Financing Calculation (\$M) ⁽¹⁾	BGE	ComEd	PECO	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	\$450	\$400	\$150	\$275	(\$1,750)	\$275	(\$200)
Dividends paid on common stock	\$225	\$500	\$350	\$350	\$900	(\$925)	\$1,400
Financing Cash Flow (Non-GAAP)	\$675	\$900	\$500	\$625	(\$850)	(\$650)	\$1,200

Exelon Total Cash Flow Reconciliation ⁽¹⁾	2019
GAAP Beginning Cash Balance	\$1,250
Adjustment for Cash Collateral Posted	\$575
Adjusted Beginning Cash Balance ⁽³⁾	\$1,825
Net Change in Cash (GAAP) ⁽²⁾	(\$250)
Adjusted Ending Cash Balance ⁽³⁾	\$1,575
Adjustment for Cash Collateral Posted	(\$850)
GAAP Ending Cash Balance	\$725

Note: Amounts may not sum due to rounding

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

(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