Earnings Conference Call
Third Quarter 2020

November 3, 2020

Exelon®

Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain written and oral forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties including among others those related to the expected or potential impact of the novel coronavirus (COVID-19) pandemic, and the related responses of various governments and regulatory bodies, our customers, and the company, on our business, financial condition and results of operations; any such forward-looking statements, whether concerning the COVID-19 pandemic or otherwise, involve risks, assumptions and uncertainties. Words such as "could," "may," "expects," "anticipates," "will," "targets," "goals," "projects," "intends," "plans," "believes," "seeks," "estimates," "predicts," and variations on such words, and similar expressions that reflect our current views with respect to future events and operational, economic and financial performance, are intended to identify such forward-looking statements.

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) the Registrants' 2019 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 18, Commitments and Contingencies; (2) the Registrants' Third Quarter 2020 Quarterly Report on Form 10-Q (to be filed on November 3, 2020) in (a) Part II, ITEM 1A. Risk Factors; (b) Part I, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, ITEM 1. Financial Statements: Note 14, Commitments and Contingencies; and (3) other factors discussed in filings with the SEC by the Registrants.

Investors are cautioned not to place undue reliance on these forward-looking statements, whether written or oral, 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

Exelon.

Non-GAAP Financial Measures Continued

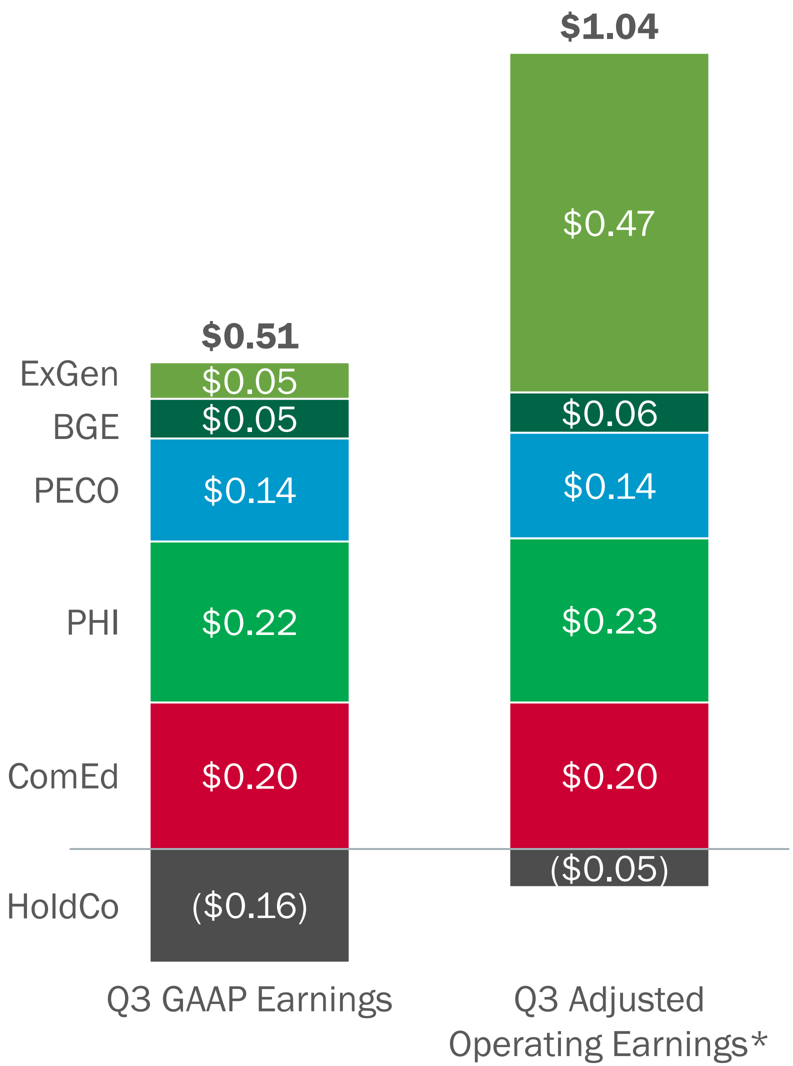
This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of Exelon's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business.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

Third Quarter Results

Q3 2020 EPS Results[1]



Q3 2020 Highlights/Key Developments

- Active summer storm season, including Tropical Storm Isaias
- Named 30 suppliers and professional services firms to Exelon Diversity and Inclusion Honor Roll
- Selected 10 startups as part of Climate Change Investment Initiative
- Announced retirements of Dresden and Byron nuclear stations and Mystic Generating station

(1) Amounts may not sum due to rounding

Exelon.

Operating Highlights

Exelon Utilities Operational Metrics

Operations	Metric	YTD 2020			
		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				
	Abandon Rate				
Gas Operations	Gas Odor Response		No Gas Operations		

- Despite storms that interrupted service in our jurisdictions, reliability performance was strong across the utilities:
  - ComEd delivered top decile CAIDI and SAIFI performance
- Each utility continued to deliver on key customer operations metrics:
  - BGE, ComEd and PECO recorded top decile performance in Customer Satisfaction
  - PHI achieved top decile performance in Abandon Rate
- BGE and PECO performed in top decile in Gas Odor Response

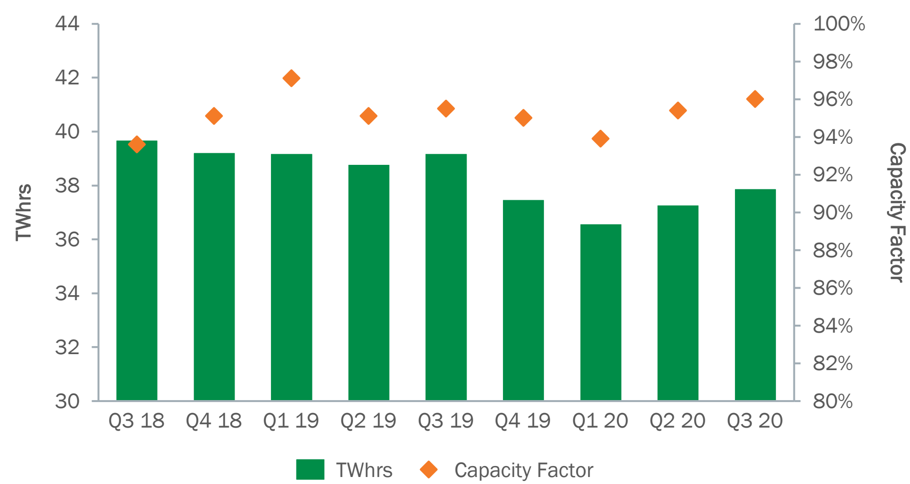
Quartile

Q1	Q2
Q3	Q4

Exelon Generation Operational Performance

Exelon Nuclear Fleet[2]

- Best in class performance across our Nuclear fleet:
  - Q3 2020 Nuclear Capacity Factor: 96.0%
  - Owned and operated Q3 2020 production of 37.9 TWh



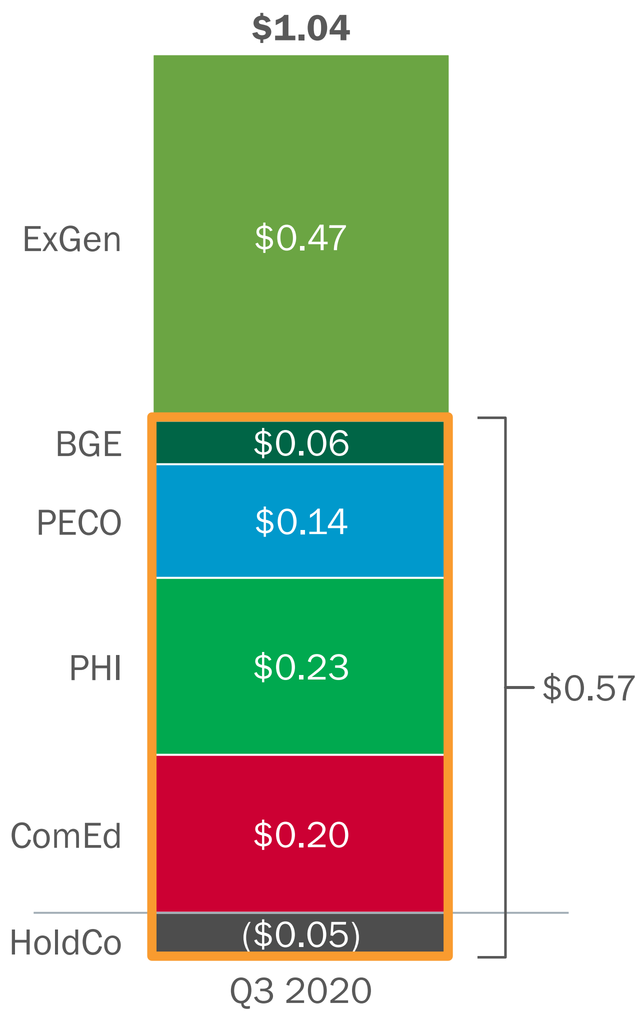
Fossil and Renewable Fleet

- Q3 2020 Power Dispatch Match: 98.9%
- Q3 2020 Renewables Energy Capture: 91.9%

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

Third Quarter Adjusted Operating Earnings* Drivers

Q3 2020 Adjusted Operating EPS* Results



Q3 2020 vs. Guidance of $0.80 - $0.90

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

Exelon Utilities

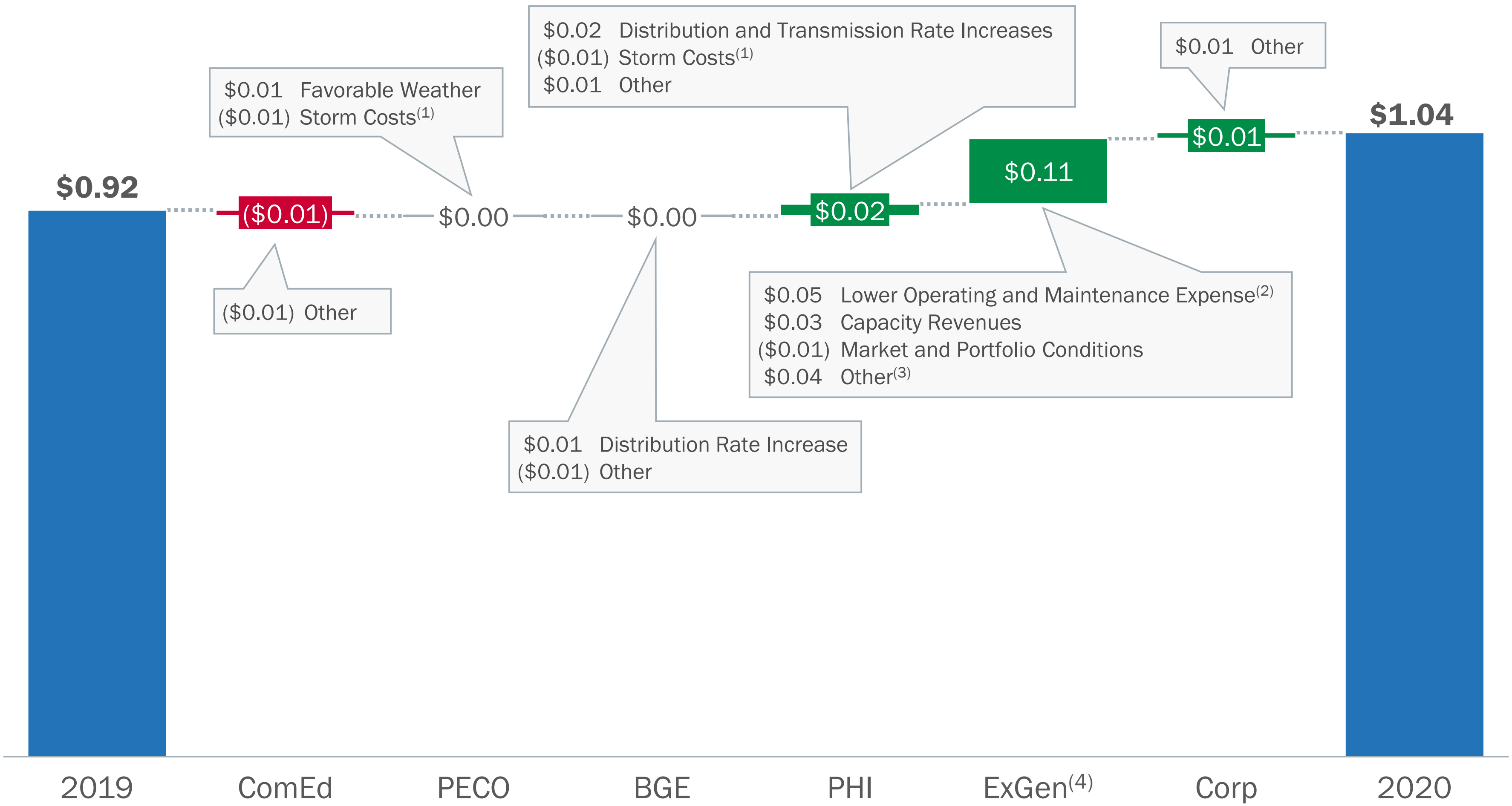
- ⬆ Favorable O&M and taxes
- ⬆ Earlier recognition of bad debt regulatory asset
- ⬆ Favorable weather
- ⬇ Storm costs

Exelon Generation

- ⬆ Favorable O&M
- ⬆ Favorable weather
- ⬆ Lower cost to serve

Note: Amounts may not sum due to rounding

Q3 2020 QTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

(1) Primarily reflects increased costs attributable to the August 2020 storm. At PECO, amount is net of tax repairs.

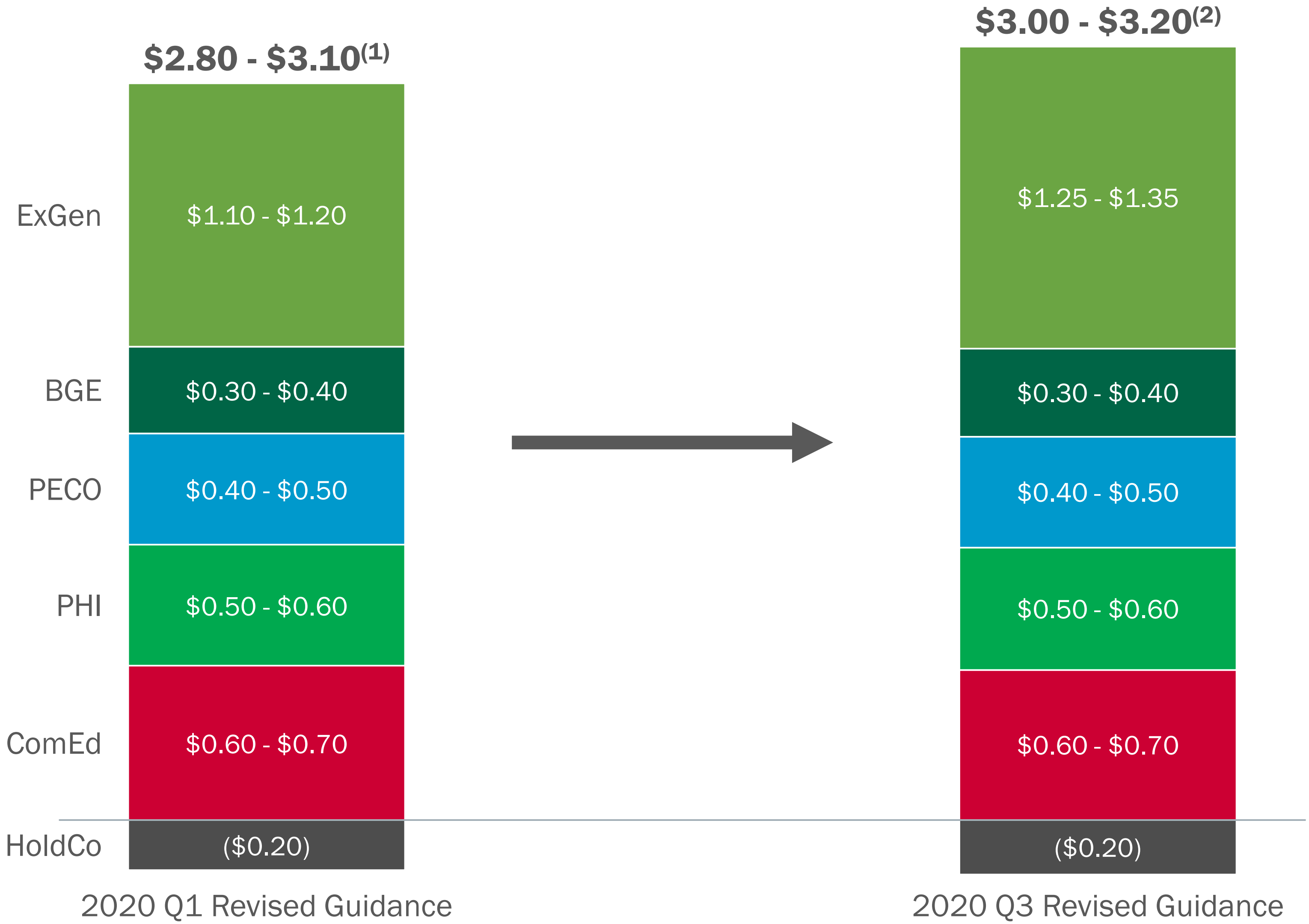
(2) Primarily reflects lower contracting and travel costs

(3) Includes the impacts of lower nuclear fuel costs

(4) Drivers reflect CENG ownership at 100%

Exelon.

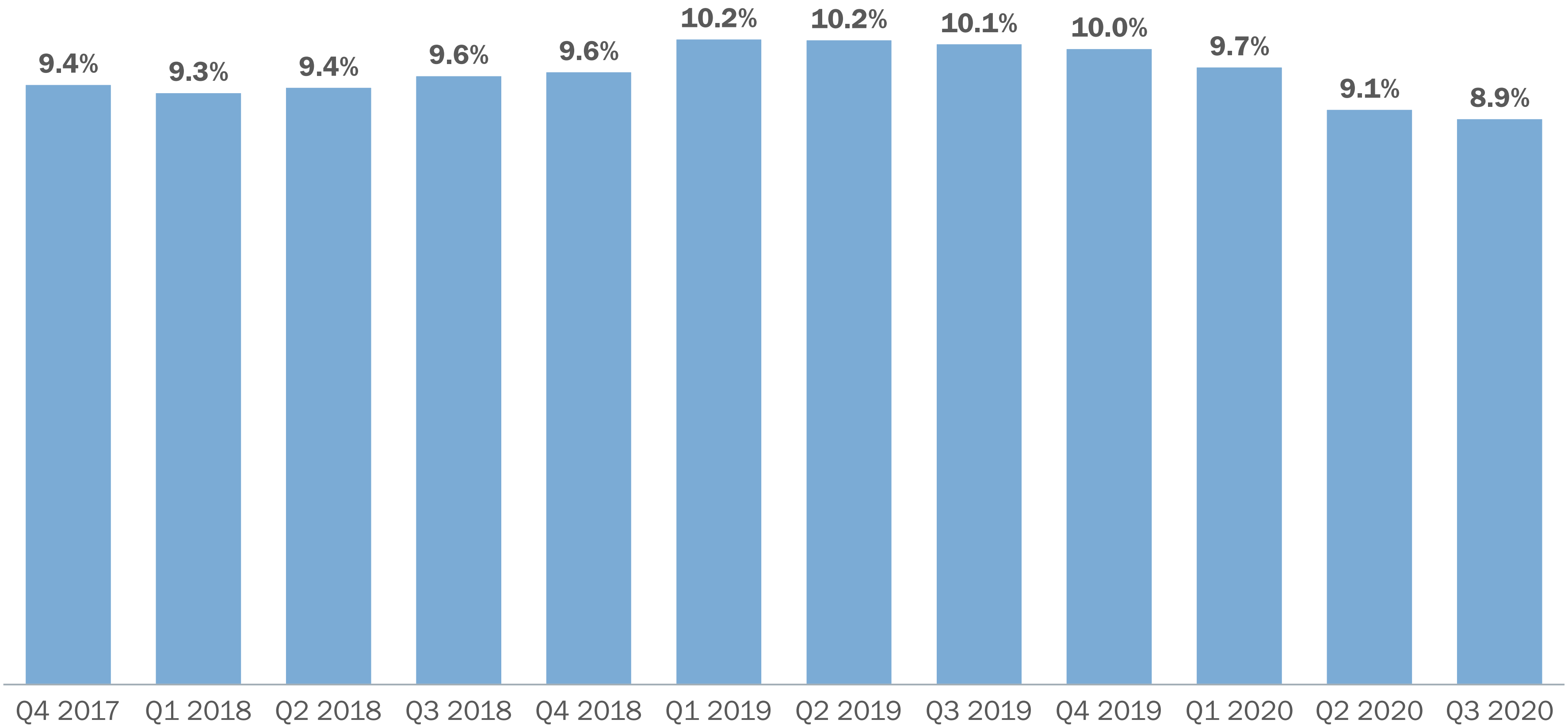
Raising 2020 Adjusted Operating Earnings* Guidance



Note: Amounts may not sum due to rounding
(1) 2020E Q1 revised earnings guidance based on expected average outstanding shares of 976M
(2) 2020E Q3 revised earnings guidance based on expected average outstanding shares of 977M

Exelon Utilities Trailing Twelve Month Earned ROEs*

Exelon Utilities' Consolidated Trailing Twelve Month Earned ROEs*



Exelon Utilities' Consolidated TTM Earned ROE* has dipped slightly below our 9-10% target range due to pressures from declining interest rates, storms and unfavorable Q1 weather

Note: Represents the twelve-month periods ending September 30, 2018-2020, June 30, 2018-2020, March 31, 2018-2020 and December 31, 2017-2019. Earned ROEs* represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Electric Transmission). Q3 2019, Q2 2019, Q1 2019, Q4 2018, Q3 2018, Q2 2018, Q1 2018 and Q4 2017 TTM ROEs* for Consolidated EU were changed from 10.1%, 10.2%, 10.2%, 9.7%, 9.6%, 9.4%, 9.4% and 9.5%, respectively, to 10.1%, 10.2%, 10.2%, 9.6%, 9.6%, 9.4%, 9.3% and 9.4%, respectively, to reflect the correction of an error at PHI.

Exelon Utilities' Distribution Rate Case Updates

Rate Case Schedule and Key Terms

	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Revenue Requirement	Requested ROE / Equity Ratio	Expected Order
ComEd	RT		EH IB	RB		FO							($13.6M)[1,2]	8.38% / 48.16%	Dec 2020
BGE		IT	RT	EH	IB RB	FO							$228.1M[1,3] 3-Year MYP	10.10% / 52.00%	Dec 2020
Pepco DC				EH		IB RB	FO	FO	FO				$135.9M[1,4] 3-Year MYP	9.70% / 50.68%	Q1 2021
DPL DE Gas			IT	RT		EH	IB RB	FO	FO				$7.2M[1,5]	10.30% / 50.37%	Q1 2021
DPL DE Electric			IT	RT				EH		FO	FO	FO	$24.0M[1,6]	10.30% / 50.37%	Q2 2021
Pepco MD				CF							FO		$110.1M[1,7] 3-Year MYP	10.20% / 50.50%	May 2021
PECO[8] Gas			CF			IT	RT	EH				FO	$68.7M[1]	10.95% / 53.38%	Jun 2021

CF Rate case filed
IT Intervenor direct testimony
RT Rebuttal testimony
EH Evidentiary hearings
IB Initial briefs
RB Reply briefs
FO Final commission order
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 ($11.5M). Through the discovery period in the current proceeding, ComEd agreed to ~($2.1M) in adjustments to limit issues in the case.

(3) Reflects 3-year cumulative multi-year plan. Company proposed incremental revenue requirement increases of $0.0M, $0.0M and $228.1M with rates effective January 1, 2021, January 1, 2022 and January 1, 2023, respectively. The proposed revenue requirement in 2023 reflects $137.0M increase for electric and $91.1M increase for gas. BGE's proposal is accomplished through a series of proforma revenue requirement adjustments to accelerate certain tax benefits, among other things.

(4) Pepco filed the multi-year plan enhanced proposal as an alternative to address the impacts of COVID-19. Reflects 3-year cumulative multi-year plan for 2020-2022. Company proposed incremental revenue requirement increases of $72.6M and $63.3M with rates effective January 1, 2022 and January 1, 2023, respectively.

(5) Requested revenue requirement excludes the transfer of $4.4M of revenues from the Distribution System Improvement Charge (DSIC) capital tracker into base distribution rates. As permitted by Delaware law, Delmarva Power implemented full allowable rates on September 21, 2020, subject to refund.

(6) Requested revenue requirement excludes the transfer of $3.4M of revenues from the Distribution System Improvement Charge (DSIC) capital tracker into base distribution rates. As permitted by Delaware law, Delmarva Power implemented full allowable rates on October 6, 2020, subject to refund.

(7) Reflects 3-year cumulative multi-year plan for April 1, 2021 through March 31, 2024. Company proposed incremental revenue requirement increases of $55.9M and $54.2M with rates effective April 1, 2023 and April 1, 2024, respectively.

(8) Anticipated schedule, actual dates will be determined by ALJ at prehearing conference

Exelon.

Featured Utility Capital Investments

Pepco's Streetlight Modernization Project in Maryland

- **Forecasted project cost:**
  - $53 million
- **In service date:**
  - Expected installation in Q1 2022 – Q4 2026
- **Project scope:**
  - Conversion of ~66,000 Maryland streetlights to Smart LEDs and integration of a Central Management System
  - Smart LED technology will reduce annual energy consumption by 60% - 80% and save approximately 119,500 tons of CO_2 over the life of the streetlight
  - Integration of Smart LED streetlights into existing AMI communications network will enable future capabilities such as pollution monitors, traffic sensors and gunshot detectors
  - Automatic notifications from the streetlights to the Central Management System will improve outage response time and maintenance efficiency

Exelon Utilities' Customer Information System Transformation

- **Forecasted project cost:**
  - $130 million
- **In service date:**
  - Completed in September 2020
- **Project scope:**
  - Upgrade of BGE's Customer Care and Billing System and implementation of Oracle's Customer Experience Service Cloud at BGE, ComEd and PECO
  - Implementation of a service-oriented front-end platform drives operational efficiencies and improved customer satisfaction
  - Enhancing existing systems to a more-standardized, cloud-based interface enables greater flexibility and more efficient integration of future strategic capabilities

Exelon Generation: Gross Margin* Update

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

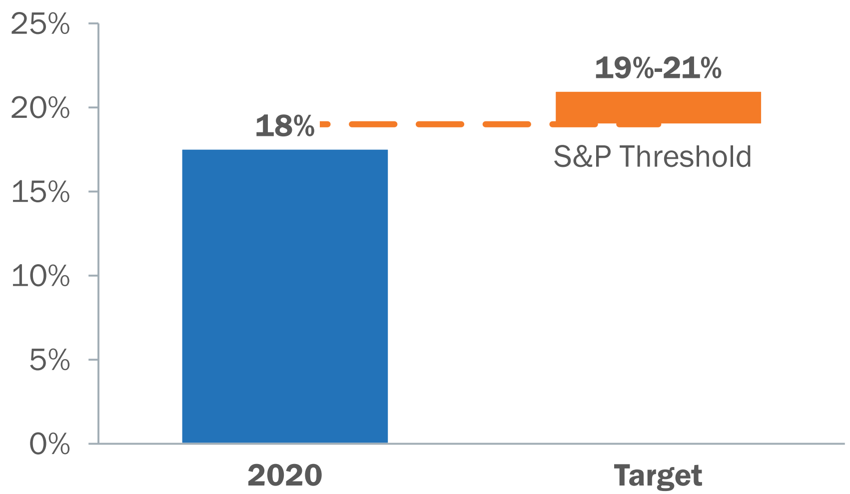
Recent Developments

- 2020 Total Gross Margin* is projected to be $50M higher primarily due to favorable Q3 weather and cost to serve
- 2021 Total Gross Margin* is projected to be $150M lower primarily due to the retirements of Byron and Dresden, which is offset by $100M of O&M, $25M of D&A and $25M of TOTI savings related to the plant closures[5]
- Executed a combined $200M of power and non-power new business in 2020 and $50M of power new business in 2021
- Behind ratable hedging position:
  – ~2-5% behind ratable in 2021 when considering cross commodity hedges

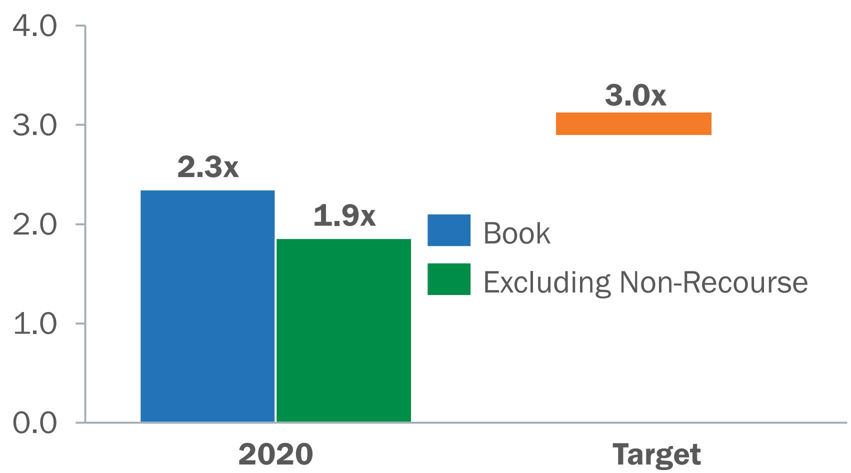
(1) Gross margin* categories rounded to nearest $50M
(2) Excludes EDF's equity ownership share of the CENG Joint Venture
(3) Mark-to-Market of Hedges assumes mid-point of hedge percentages
(4) Based on September 30, 2020 market conditions
(5) Reflects Byron and Dresden retirements in September 2021 and November 2021, respectively. See Additional ExGen Modeling Data (slide 36) for P&L offsets from the plant retirements.

Maintaining Strong Investment Grade Credit Ratings is a Top Financial Priority

Exelon S&P FFO/Debt %*(1)



ExGen Debt/EBITDA Ratio*(2)



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) 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
(2) Reflects net book debt (YE debt less cash on hand) / adjusted operating EBITDA*
(3) Current senior unsecured ratings as of September 30, 2020, for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco

The Exelon Value Proposition

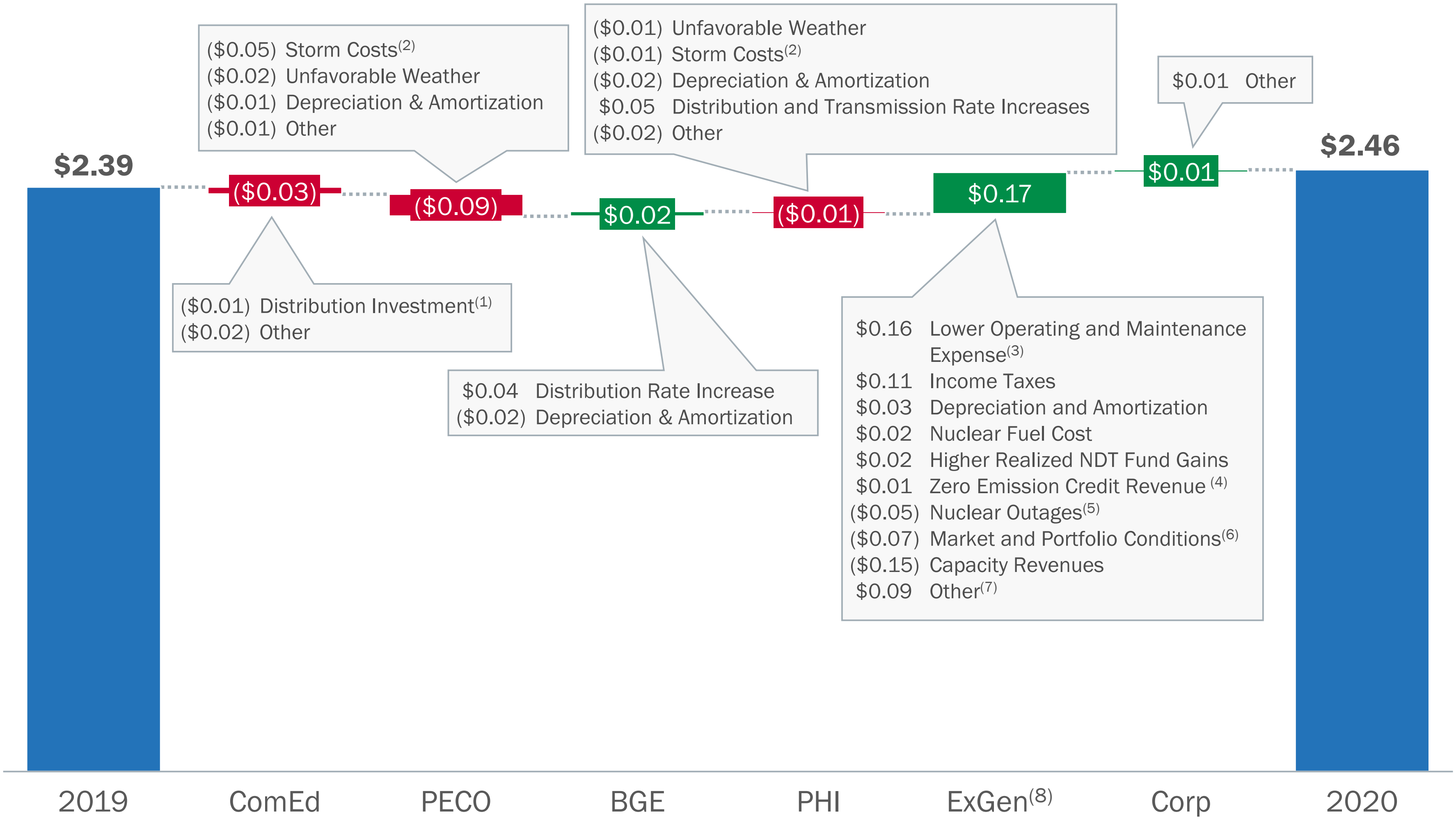
- **Regulated Utility Growth** targeting utility EPS rising 6-8% annually from 2019-2023 and rate base growth of 7.3%, representing an expanding majority of earnings
- **ExGen's free cash generation** will support utility growth, ExGen debt reduction, and the external dividend
- **Optimizing ExGen value 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 2023 planning horizon
- **Capital allocation priorities targeting:**
  - Organic utility growth;
  - Return of capital to shareholders with 5% annual dividend growth through 2020[(1)]; and,
  - Debt reduction

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

Exelon.

Additional Disclosures

Q3 2020 YTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

(1) Reflects lower allowed electric distribution ROE due to a decrease in treasury rates, partially offset by higher rate base

(2) At PECO, primarily reflects increased costs attributable to the June 2020 and August 2020 storms, net of tax repairs. At PHI, primarily reflects increased costs attributable to the August 2020 storm.

(3) Includes the impacts of previous cost management programs, lower contracting costs and lower travel costs

(4) Primarily reflects the approval of the New Jersey ZEC Program in the second quarter of 2019

(5) Reflects the revenue and operating and maintenance expense impacts of higher nuclear outage days in 2020, excluding Salem, partially offset by the impacts of lower nuclear outage days at Salem in 2020

(6) Primarily reflects reduction in load due to mild weather in the first quarter of 2020 and COVID-19, partially offset by higher portfolio optimization

(7) Primarily reflects the elimination of activity attributable to noncontrolling interest, primarily for CENG

(8) Drivers reflect CENG ownership at 100%

2020 Projected Sources and Uses of Cash

($M)[1]	BGE	ComEd	PECO	PHI	Total Utilities	ExGen	Corp[9]	Exelon	Cash Balance
Beginning Cash Balance*[2]									**1,500**
Adjusted Cash Flow from Operations[2]	800	1,250	850	900	3,800	3,500	(350)	6,950	
Base CapEx and Nuclear Fuel[3]	-	-	-	-	-	(1,525)	(125)	(1,650)	
Free Cash Flow*	**800**	**1,250**	**850**	**900**	**3,800**	**1,975**	**(475)**	**5,300**	
Debt Issuances	400	1,000	350	500	2,250	900	2,000	5,150	
Debt Retirements	-	(500)	-	-	(500)	(2,500)	(900)	(3,900)	
Project Financing	-	-	-	-	-	(125)	-	(125)	
Equity Issuance/Share Buyback	-	-	-	-	-	-	-	-	
AR Securitization[4]	-	-	-	-	-	500	-	500	
Contribution from Parent	400	725	225	250	1,600	-	(1,600)	-	
Other[5]	(75)	300	100	200	550	150	(250)	450	
Financing*[6]	**725**	**1,525**	**700**	**950**	**3,900**	**(1,075)**	**(750)**	**2,050**	
Total Free Cash Flow and Financing*	**1,550**	**2,775**	**1,550**	**1,850**	**7,700**	**875**	**(1,225)**	**7,350**	
Utility Investment	(1,300)	(2,325)	(1,200)	(1,625)	(6,450)	-	-	(6,450)	
ExGen Growth[3,7]	-	-	-	-	-	(125)	-	(125)	
Acquisitions and Divestitures	-	-	-	-	-	-	-	-	
Equity Investments	-	-	-	-	-	50	-	50	
Dividend[8]	-	-	-	-	-	-	-	(1,500)	
Other CapEx and Dividend	**(1,300)**	**(2,325)**	**(1,200)**	**(1,625)**	**(6,450)**	**(75)**	**-**	**(8,000)**	
Total Cash Flow*	**250**	**425**	**350**	**225**	**1,275**	**825**	**(1,225)**	**(650)**	
Ending Cash Balance*[2]									**875**

(1) All amounts rounded to the nearest $25M. Figures may not sum due to rounding.
(2) Gross of posted counterparty collateral
(3) Figures reflect cash CapEx and CENG fleet at 100%
(4) Proceeds from securitization of Constellation Accounts Receivable Portfolio
(5) Other primarily includes expected changes in commercial paper, tax sharing from the parent, renewable JV distributions, tax equity cash flows, debt issuance costs and other financing activities
(6) Financing cash flow excludes intercompany dividends
(7) ExGen Growth CapEx primarily includes Retail Solar and W. Medway
(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 $5,300M of free cash flow*, including $1,975M at ExGen and $3,800M at the Utilities

Supported by a strong balance sheet

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

- ✓ $1,750M of long-term debt at the utilities, net of refinancing, to support continued growth
- ✓ Retirement of $1,600M long-term debt at ExGen, net of refinancing and excluding A/R Securitization and Project Financing

Enable growth & value creation

Creating value for customers, communities and shareholders

- ✓ Investing $6,575M of growth CapEx, with $6,450M at the Utilities and $125M at ExGen

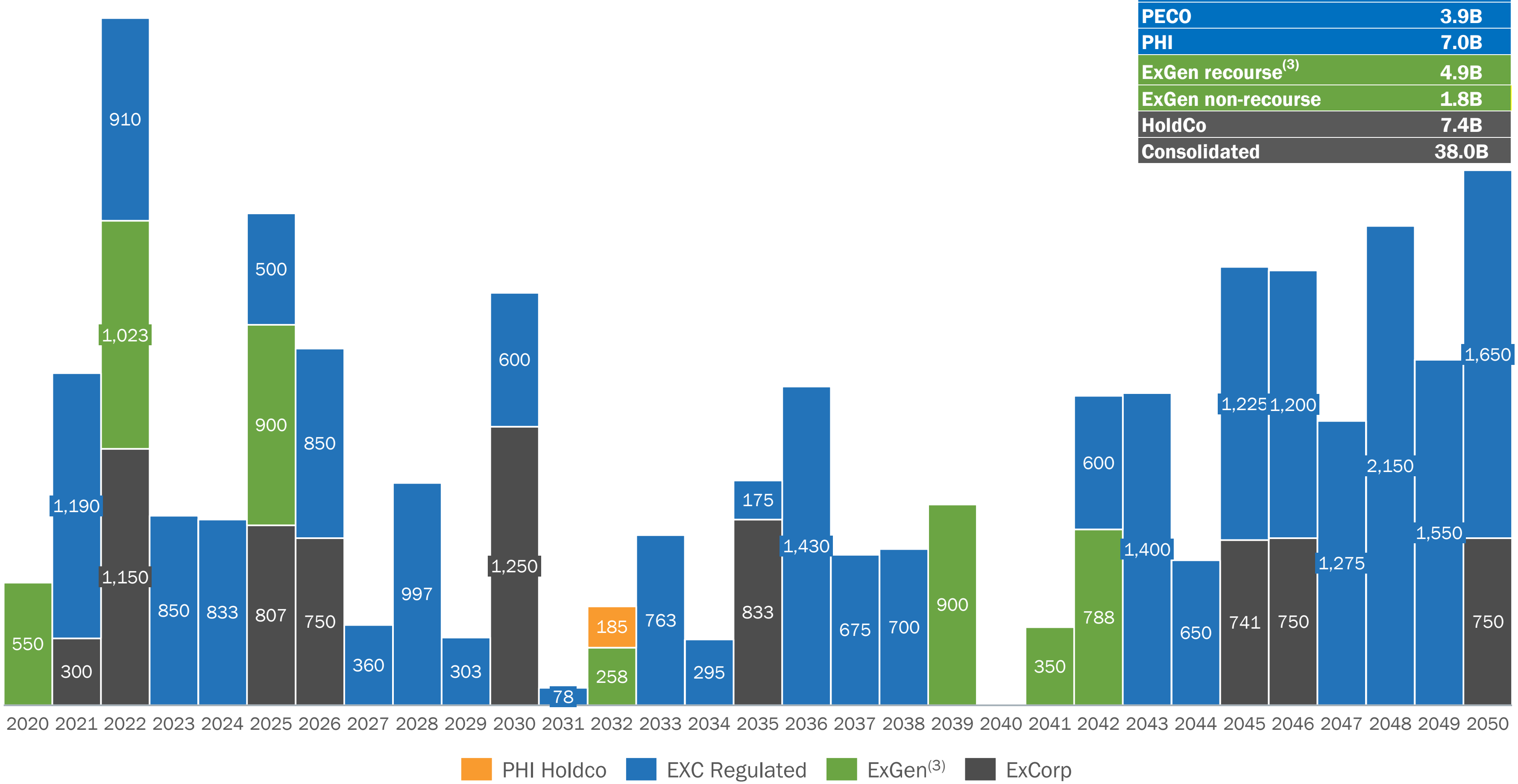
Exelon

Exelon Debt Maturity Profile[1,2]

As of 9/30/2020

($M)

LT Debt Balances (as of 9/30/20)[1,2]	
BGE	3.7B
ComEd	9.2B
PECO	3.9B
PHI	7.0B
ExGen recourse[3]	4.9B
ExGen non-recourse	1.8B
HoldCo	7.4B
Consolidated	38.0B



Exelon's weighted average LTD maturity is approximately 16 years

(1) Maturity profile excludes non-recourse debt, securitized debt, capital leases, fair value adjustments, unamortized debt issuance costs and unamortized discount/premium
(2) Long-term debt balances reflect Q3 2020 10-Q GAAP financials, which include items listed in footnote 1. On October 2, 2020, ExGen retired $550M of legacy CEG debt.
(3) Includes legacy CEG debt of $550M and $258M in 2020 and 2032

Exelon Utilities

ComEd Distribution Rate Case Filing

	Rate Case Filing Details	Notes
Docket No.	20-0393	• April 16, 2020, ComEd filed its annual distribution formula rate update with the Illinois Commerce Commission seeking a decrease to distribution base rates. A Final Order is expected in early December. • October 14, 2020, draft proposed orders were filed by ComEd, ICC Staff and intervenors • A final Order from the Commission is expected in early December
Test Year	January 1, 2019 – December 31, 2019	
Test Period	2019 Actual Costs + 2020 Projected Plant Additions	
Proposed Common Equity Ratio	48.16%	
Proposed Rate of Return	ROE: 8.38%; ROR: 6.28%	
Proposed Rate Base (Adjusted)	$12,051M	
Requested Revenue Requirement Decrease	($13.6M)[1,2]	
Residential Total Bill % Decrease	(1.3%)	

Detailed Rate Case Schedule

	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Filed rate case		4/16/2020										
Intervenor testimony				6/30/2020								
Rebuttal testimony					7/28/2020							
Evidentiary hearings							9/10/2020					
Initial briefs							9/28/2020					
Reply briefs								10/13/2020				
Commission order expected										12/2020		

(1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings
(2) Revenue requirement in initial filing was a decrease of ($11.5M). Through the discovery period in the current proceeding, ComEd agreed to ~($2.1M) in adjustments to limit issues in the case.

BGE Distribution Rate Case Filing

Multi-Year Plan Case Filing Details	
Formal Case No.	9645
Test Year	January 1 – December 31
Test Period	2021, 2022, 2023
Proposed Common Equity Ratio	52.00%
2021-2023 Proposed Rate of Return	ROE: 10.10%, 10.10%, 10.10% ROR: 7.09%, 7.10%, 7.09%
2021-2023 Proposed Rate Base (Adjusted)	\$6.5B, \$7.1B, \$7.7B
2021-2023 Requested Revenue Requirement Increase[1,2]	\$0.0M, \$0.0M, \$228.1M
2021-2023 Residential Total Bill % Increase[2]	0.0%, 0.0%, 8.0%

Notes

- May 15, 2020, BGE filed a three year multi-year plan (MYP) request with the Maryland Public Service Commission (MDPSC) seeking an increase in electric and gas distribution base rates
- Size of ask is driven by continued investments in electric and gas distribution system to maintain and increase reliability and customer service
- In light of COVID-19 pandemic, MYP includes measures to mitigate revenue requirement needs while preserving BGE's ability to execute its capital and O&M plans and earn the authorized return[3]

Detailed Rate Case Schedule

	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan
Filed rate case	5/15/2020								
Intervenor testimony				8/14/2020					
Rebuttal testimony					9/11/2020				
Evidentiary hearings						10/13/2020 - 10/21/2020			
Initial briefs							11/4/2020		
Reply briefs							11/12/2020		
Commission order expected								12/16/2020	

(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 January 1, 2021, January 1, 2022 and January 1, 2023, respectively. The proposed revenue requirement in 2023 reflects \$137.0M increase for electric and \$91.1M increase for gas.
(3) Measures include decreasing a performance adder included in its recommended return on equity and proposing a series of proforma adjustments to change the method for recovery of major storm costs, accelerate certain tax benefits, suspend regulatory asset amortization in 2021 and extend the amortization periods of certain existing regulatory assets

Pepco DC Distribution Rate Case Filing

Multi-Year Plan Case Filing Details

Formal Case No.	1156
Test Year	January 1 – December 31
Test Period	2020, 2021, 2022
Proposed Common Equity Ratio	50.68%
Proposed Rate of Return	ROE: 9.70%; ROR: 7.39%
2020-2022 Proposed Rate Base (Adjusted)	$2.2B, $2.4B, $2.6B
2020-2022 Requested Revenue Requirement Increase(1,2)	$0.0M, $0.0M, $72.6M, $63.3M
2020-2022 Residential Total Bill % Increase(2)	0.0%, 0.0%, 4.6%, 6.6%

Notes

- 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
- MYP proposes five tracking Performance Incentive Mechanisms (PIMs) focused on system reliability, customer service and interconnection Distributed Energy Resources (DER)
- June 1, 2020, Pepco DC filed MYP Enhanced Proposal to address impact of COVID-19. The proposal includes an offset to distribution rates allowing for no overall distribution increase until January 2022 and several customer assistance programs.

Detailed Rate Case Schedule

May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar

Filed rate case	5/30/2019
Intervenor testimony	3/6/2020
Rebuttal testimony	4/8/2020
Evidentiary hearings	10/26/2020 - 10/30/2020
Initial briefs	12/9/2020
Reply briefs	12/23/2020
Commission order expected	Q1 2021

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

(2) Pepco filed the multi-year plan enhanced proposal as an alternative to address the impacts of COVID-19. Reflects 3-year cumulative multi-year plan for 2020-2022. Company proposed incremental revenue requirement increases of $72.6M and $63.3M with rates effective January 1, 2022 and January 1, 2023, respectively.

Exelon

Delmarva DE (Gas) Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	20-0150
Test Year	April 1, 2019 – March 31, 2020
Test Period	9 months actual + 3 months estimated
Proposed Common Equity Ratio	50.37%
Proposed Rate of Return	ROE: 10.30%; ROR: 7.15%
Proposed Rate Base (Adjusted)	$399.7M
Requested Revenue Requirement Increase	$7.2M(1,2)
Residential Total Bill % Increase	4.7%

Notes

- February 21, 2020, Delmarva Power filed an application with the Delaware Public Service Commission (DPSC) seeking an increase in gas distribution base rates
- Size of ask is driven by continued investments in gas distribution system to maintain and increase reliability and customer service

Detailed Rate Case Schedule

Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr

Filed rate case	2/21/2020
Intervenor testimony	9/1/2020
Rebuttal testimony	10/9/2020
Evidentiary hearings	12/3/2020 - 12/4/2020
Initial briefs	1/11/2021
Reply briefs	1/29/2021
Commission order expected	Q1 2021

(1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings
(2) Requested revenue requirement excludes the transfer of $4.4M of revenues from the Distribution System Improvement Charge (DSIC) capital tracker into base distribution rates. As permitted by Delaware law, Delmarva Power implemented full allowable rates on September 21, 2020, subject to refund.

Exelon.

Delmarva DE (Electric) Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	20-0149
Test Year	April 1, 2019 – March 31, 2020
Test Period	9 months actual + 3 months estimated
Proposed Common Equity Ratio	50.37%
Proposed Rate of Return	ROE: 10.30%; ROR: 7.15%
Proposed Rate Base (Adjusted)	$922.1M
Requested Revenue Requirement Increase	$24.0M[1,2]
Residential Total Bill % Increase	3.5%

Notes

- March 6, 2020, Delmarva Power filed an application with the Delaware Public Service Commission (DPSC) seeking an increase in electric distribution base rates
- Size of ask is driven by continued investments in electric distribution system to maintain and increase reliability and customer service

Detailed Rate Case Schedule

Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May Jun Jul

Filed rate case	3/6/2020
Intervenor testimony	9/9/2020
Rebuttal testimony	10/26/2020
Evidentiary hearings	2/11/2021 - 2/12/2021
Initial briefs	
Reply briefs	
Commission order expected	Q2 2021

(1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings
(2) Requested revenue requirement excludes the transfer of $3.4M of revenues from the Distribution System Improvement Charge (DSIC) capital tracker into base distribution rates. As permitted by Delaware law, Delmarva Power implemented full allowable rates on October 6, 2020, subject to refund.

Pepco MD Distribution Rate Case Filing

Multi-Year Plan Case Filing Details	
Formal Case No.	9655
Test Year	April 1 – March 31
Test Period	2022, 2023, 2024
Proposed Common Equity Ratio	50.50%
Proposed Rate of Return	ROE: 10.20%; ROR: 7.54%
2022-2024 Proposed Rate Base (Adjusted)	$2.4B, $2.6B, $2.8B
2022-2024 Requested Revenue Requirement Increase[1,2]	$0.0M, $0.0M, $55.9M, $54.2M
2022-2024 Residential Total Bill % Increase[2]	0.0%, 0.0%, 4.4%, 4.2%

Notes

- October 26, 2020, Pepco MD filed a three-year multi-year plan (MYP) request with the Maryland Public Service Commission (MDPSC) seeking an increase in electric distribution base rates
- MYP proposes five tracking only Performance Incentive Mechanisms (PIMs) focused on system reliability, customer service and environmental
- The proposal includes an offset to distribution rates allowing for no overall distribution increase until April 2023

Detailed Rate Case Schedule

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Filed rate case	▲ 10/26/2020											
Intervenor testimony												
Rebuttal testimony												
Evidentiary hearings												
Initial briefs												
Reply briefs												
Commission order expected									5/2021			

(1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings
(2) Reflects 3-year cumulative multi-year plan for April 1, 2021 through March 31, 2024. Company proposed incremental revenue requirement increases of $55.9M and $54.2M with rates effective April 1, 2023 and April 1, 2024, respectively.

PECO (Gas) Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	R-2020-3018929
Test Year	July 1, 2021 – June 30, 2022
Test Period	12 Months Budget
Proposed Common Equity Ratio	53.38%
Proposed Rate of Return	ROE: 10.95%; ROR: 7.70%
Proposed Rate Base (Adjusted)	$2,462M
Requested Revenue Requirement Increase	$68.7M(1)
Residential Total Bill % Increase	9.0%

Notes

- On September 30, 2020, PECO filed a general base rate filing with the Pennsylvania Public Utility Commission (PAPUC) seeking an increase in gas distribution base rates
- Size of ask is driven by continued investments in gas distribution system to maintain and increase safety, reliability and customer service

Detailed Rate Case Schedule(2)

	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Filed rate case	9/30/2020												
Intervenor testimony				12/2020									
Rebuttal testimony					1/2021								
Evidentiary hearings						2/2021							
Commission order expected										6/2021			

(1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings
(2) Anticipated schedule, actual dates will be determined by ALJ at prehearing conference

Exelon Generation Disclosures

September 30, 2020

Portfolio Management Strategy

Strategic Policy Alignment

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

Three-Year Ratable Hedging

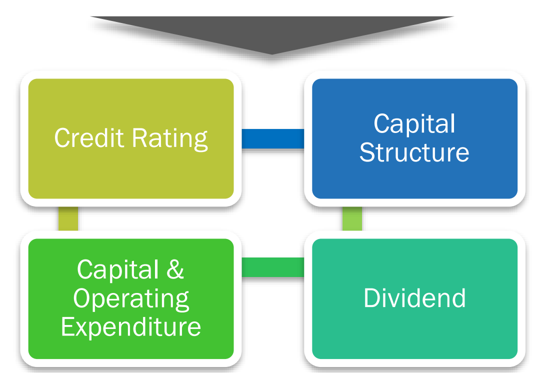
- Ensure stability in near-term cash flows and earnings
  - Disciplined approach to hedging
  - Tenor aligns with customer preferences and market liquidity
  - Multiple channels to market that allow us to maximize margins
  - Large open position in outer years to benefit from price upside

Bull / Bear Program

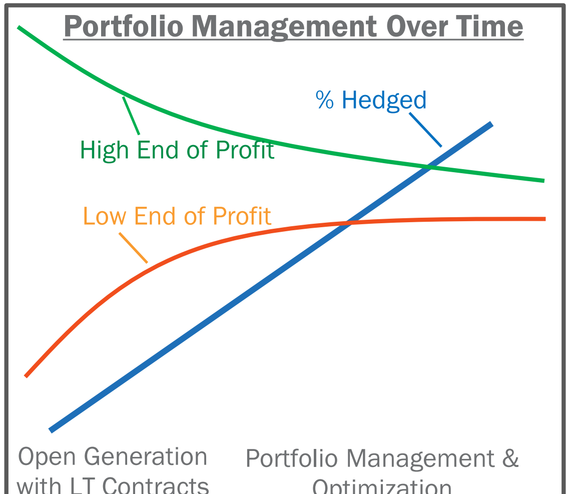
- Ability to exercise fundamental market views to create value within the ratable framework
  - Modified timing of hedges versus purely ratable
  - Cross-commodity hedging (heat rate positions, options, etc.)
  - Delivery locations, regional and zonal spread relationships

Align Hedging & Financials

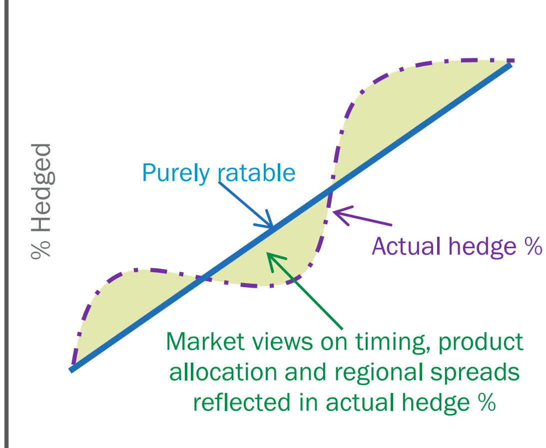
Establishing Minimum Hedge Targets



Portfolio Management Over Time



Exercising Market Views



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

Exelon.

Components of Gross Margin* Categories

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

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

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

(1) Hedged gross margins* for South, West, New England & 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 four 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, 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, 2020 2020	September 30, 2020 2021
Open Gross Margin (including South, West, New England & Canada hedged GM)*[2,5]	$2,750	$3,550
Capacity and ZEC Revenues[2]	$1,900	$1,800
Mark-to-Market of Hedges[2,3]	$1,850	$250
Power New Business / To Go	$100	$550
Non-Power Margins Executed	$400	$250
Non-Power New Business / To Go	$50	$250
Total Gross Margin*[4,5]	**$7,050**	**$6,650**

Reference Prices[4]	2020	2021
Henry Hub Natural Gas ($/MMBtu)	$2.06	$2.92
Midwest: NiHub ATC prices ($/MWh)	$19.22	$24.68
Mid-Atlantic: PJM-W ATC prices ($/MWh)	$21.31	$28.67
ERCOT-N ATC Spark Spread ($/MWh) *HSC Gas, 7.2HR, $2.50 VOM*	$3.71	$8.00
New York: NY Zone A ($/MWh)	$18.80	$26.51

(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, 2020 market conditions
(5) Reflects Byron and Dresden retirements in September 2021 and November 2021, respectively

ExGen Disclosures

Generation and Hedges	September 30, 2020 2020	2021
Expected Generation (GWh)[1]	**179,500**	**173,000**
Midwest[6]	97,900	87,900
Mid-Atlantic[2]	47,900	47,900
ERCOT	18,100	20,600
New York[2]	15,600	16,600
% of Expected Generation Hedged[3]	**97%-100%**	**87%-90%**
Midwest[6]	97%-100%	88%-91%
Mid-Atlantic[2]	98%-101%	88%-91%
ERCOT	97%-100%	87%-90%
New York[2]	95%-98%	80%-83%
Effective Realized Energy Price ($/MWh)[4]		
Midwest[6]	$28.00	$25.50
Mid-Atlantic[2]	$36.50	$31.50
ERCOT[5]	$10.50	$9.00
New York[2]	$30.50	$27.50

(1) Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 14 refueling outages in 2020 and 11 in 2021 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 95.1% and 94.6% in 2020 and 2021, respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 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 Byron and Dresden retirements in September 2021 and November 2021, respectively

ExGen Hedged Gross Margin* Sensitivities

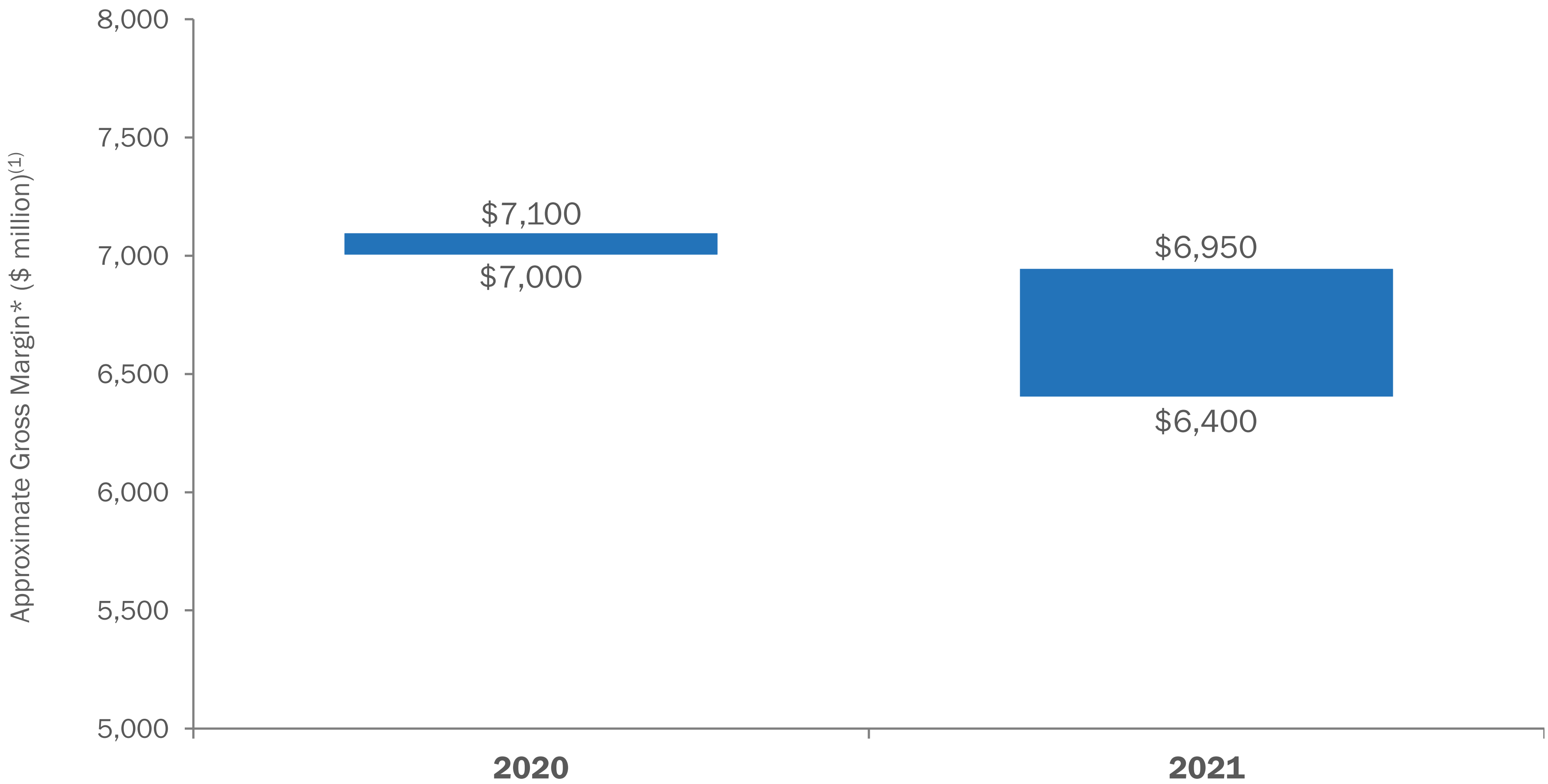
September 30, 2020

Gross Margin* Sensitivities (with existing hedges)[1,2]	2020	2021
Henry Hub Natural Gas ($/MMBtu)		
+ $1/MMBtu	$40	$235
- $1/MMBtu	$(35)	$(170)
NiHub ATC Energy Price		
+ $5/MWh	-	$40
- $5/MWh	-	$(40)
PJM-W ATC Energy Price		
+ $5/MWh	$5	$35
- $5/MWh	$(5)	$(30)
NYPP Zone A ATC Energy Price		
+ $5/MWh	$5	$10
- $5/MWh	$(5)	$(10)
Nuclear Capacity Factor		
+/- 1%	+/- $5	+/- $30

(1) Based on September 30, 2020 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

(2) These sensitivities do not capture changes to underlying assumptions for COVID-19

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 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, 2020. Gross Margin* Upside/Risk based on commodity exposure which includes open generation and all committed transactions. Reflects Byron and Dresden retirements in September 2021 and November 2021, respectively.

Illustrative Example of Modeling Exelon Generation 2021 Total Gross Margin*

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York
(A)	Start with fleet-wide open gross margin*	$3.55 billion			
(B)	Capacity and ZEC	$1.8 billion			
(C)	Expected Generation (TWh)	87.9	47.9	20.6	16.6
(D)	Hedge % (assuming mid-point of range)	89.5%	89.5%	88.5%	81.5%
(E=C*D)	Hedged Volume (TWh)	78.7	42.9	18.2	13.5
(F)	Effective Realized Energy Price ($/MWh)	$25.50	$31.50	$9.00	$27.50
(G)	Reference Price ($/MWh)	$24.68	$28.67	$8.00	$26.51
(H=F-G)	Difference ($/MWh)	$0.82	$2.83	$1.00	$0.99
(I=E*H)	Mark-to-Market value of hedges ($ million)[1]	$65	$125	$20	$15
(J=A+B+I)	Hedged Gross Margin ($ million)	$5,600			
(K)	Power New Business / To Go ($ million)	$550			
(L)	Non-Power Margins Executed ($ million)	$250			
(M)	Non-Power New Business / To Go ($ million)	$250			
(N=J+K+L+M)	**Total Gross Margin***	**$6,650 million**			

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

Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in $M)[1]	2020	2021
Revenue Net of Purchased Power and Fuel Expense*[2,3]	**$7,450**	**$7,075**
Other Revenues[4]	$(175)	$(150)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses	$(225)	$(275)
Total Gross Margin* (Non-GAAP)	**$7,050**	**$6,650**

Key ExGen Modeling Inputs (in $M)[1,5]	2020	2021
Other[6]	$225	$125
Adjusted O&M*[7]	$(4,000)	$(4,050)
Taxes Other Than Income (TOTI)[8]	$(375)	$(350)
Depreciation & Amortization*	$(1,025)	$(1,050)
Interest Expense	$(325)	$(325)
Effective Tax Rate	**20.0%**	**23.0%**

(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 and gross receipts tax revenues
(5) ExGen O&M, TOTI and 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
(7) 2020 and 2021 Adjusted O&M* includes $150M of non-cash expense related to the increase in the ARO liability due to the passage of time
(8) 2020 and 2021 TOTI excludes gross receipts tax of $125M

Appendix

Reconciliation of Non-GAAP Measures

Q3 QTD GAAP EPS Reconciliation

Three Months Ended September 30, 2020	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
2020 GAAP Earnings (Loss) Per Share	**$0.20**	**$0.14**	**$0.05**	**$0.22**	**$0.05**	**($0.16)**	**$0.51**
Mark-to-market impact of economic hedging activities	-	-	-	-	(0.20)	0.01	(0.19)
Unrealized gains related to NDT funds	-	-	-	-	(0.18)	-	(0.18)
Asset Impairments	-	-	-	-	0.38	-	0.38
Plant retirements and divestitures	-	-	-	-	0.34	-	0.34
Cost management program	-	-	-	-	0.01	-	0.02
Change in environmental liabilities	-	-	-	-	0.02	-	0.02
COVID-19 direct costs	-	-	-	-	0.01	-	0.01
Income tax-related adjustments	-	-	-	-	(0.03)	0.09	0.06
Noncontrolling interests	-	-	-	-	0.06	-	0.06
2020 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.20**	**$0.14**	**$0.06**	**$0.23**	**$0.47**	**($0.05)**	**$1.04**

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

Exelon.

Q3 QTD GAAP EPS Reconciliation (continued)

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.

Exelon.

Q3 YTD GAAP EPS Reconciliation

Nine Months Ended September 30, 2020	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
2020 GAAP Earnings (Loss) Per Share	**$0.31**	**$0.32**	**$0.28**	**$0.43**	**$0.58**	**($0.28)**	**$1.64**
Mark-to-market impact of economic hedging activities	-	-	-	-	(0.36)	0.02	(0.34)
Unrealized losses related to NDT funds	-	-	-	-	0.01	-	0.01
Asset Impairments	0.01	-	-	-	0.39	-	0.40
Plant retirements and divestitures	-	-	-	-	0.36	-	0.36
Cost management program	-	-	-	0.01	0.03	-	0.03
Change in Environmental Liabilities	-	-	-	-	0.02	-	0.02
COVID-19 direct costs	-	0.01	-	-	0.02	-	0.04
Deferred Prosecution Agreement payments	0.20	-	-	-	-	-	0.20
Income Tax-Related Adjustments	-	-	-	-	(0.03)	0.10	0.07
Noncontrolling interests	-	-	-	-	0.02	-	0.02
2020 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.53**	**$0.33**	**$0.29**	**$0.44**	**$1.04**	**($0.17)**	**$2.46**

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, 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.

Projected GAAP to Operating Adjustments

- **Exelon's projected 2020 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;
  - Certain costs related to plant retirements;
  - Certain costs incurred to achieve cost management program savings;
  - Certain costs related to changes in environmental liabilities;
  - Direct costs related to COVID-19;
  - Deferred Prosecution Agreement payments;
  - Update to long term state tax marginal rates;
  - Other items not directly related to the ongoing operations of the business; and
  - Generation's noncontrolling interest related to CENG exclusion items.

GAAP to Non-GAAP Reconciliations[1]

Exelon FFO/Debt[2] $= \dfrac{\text{FFO (a)}}{\text{Adjusted Debt (b)}}$

Exelon FFO Calculation[2]

GAAP Operating Income
<u>+ Depreciation & Amortization</u>
= EBITDA
- Interest Expense
+/- Cash Taxes
+ Nuclear Fuel Amortization
+/- Mark-to-Market Adjustments (Economic Hedges)
<u>+/- Other S&P Adjustments</u>
= 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)
+ AR Securitization Imputed Debt
- Off-Credit Treatment of Non-Recourse Debt
- Cash on Balance Sheet
<u>+/- Other S&P Adjustments</u>
= 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

GAAP to Non-GAAP Reconciliations[1]

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

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

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

Consolidated EU Operating TTM ROE Reconciliation ($M)	Q3 2020	Q2 2020	Q1 2020
Net Income (GAAP)	1,747	$1,728	$2,060
Operating Exclusions	243	$254	$31
Adjusted Operating Earnings	1,990	$1,982	$2,091
Average Equity	22,329	$21,885	$21,502
Operating (Non-GAAP) TTM ROE (Adjusted Operating Earnings/Average Equity)	**8.9%**	**9.1%**	**9.7%**

Consolidated EU Operating TTM ROE Reconciliation ($M)	Q4 2019	Q3 2019	Q2 2019	Q1 2019
Net Income (GAAP)	$2,065	$2,037	$2,011	$1,967
Operating Exclusions	$30	$33	$31	$33
Adjusted Operating Earnings	$2,095	$2,070	$2,042	$1,999
Average Equity	$20,913	$20,500	$20,111	$19,639
Operating (Non-GAAP) TTM ROE (Adjusted Operating Earnings/Average Equity)	**10.0%**	**10.1%**	**10.2%**	**10.2%**

Consolidated EU Operating TTM ROE Reconciliation ($M)	Q4 2018	Q3 2018	Q2 2018	Q1 2018
Net Income (GAAP)	$1,836	$1,770	$1,724	$1,643
Operating Exclusions	$32	$40	$13	$32
Adjusted Operating Earnings	$1,869	$1,810	$1,737	$1,675
Average Equity	$19,367	$18,878	$18,467	$17,969
Operating (Non-GAAP) TTM ROE (Adjusted Operating Earnings/Average Equity)	**9.6%**	**9.6%**	**9.4%**	**9.3%**

Consolidated EU Operating TTM ROE Reconciliation ($M)	Q4 2017
Net Income (GAAP)	$1,704
Operating Exclusions	($24)
Adjusted Operating Earnings	$1,680
Average Equity	$17,779
Operating (Non-GAAP) TTM ROE (Adjusted Operating Earnings/Average Equity)	**9.4%**

Note: Represents the twelve-month periods ending September 30, 2018-2020, June 30, 2018-2020, March 31, 2018-2020 and December 31, 2017-2019. Earned ROEs* represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Electric Transmission). Q3 2019, Q2 2019, Q1 2019, Q4 2018, Q3 2018, Q2 2018, Q1 2018 and Q4 2017 TTM ROEs* for Consolidated EU were changed from 10.1%, 10.2%, 10.2%, 9.7%, 9.6%, 9.4%, 9.4% and 9.5%, respectively, to 10.1%, 10.2%, 10.2%, 9.6%, 9.6%, 9.4%, 9.3% and 9.4%, respectively, to reflect the correction of an error at PHI.

GAAP to Non-GAAP Reconciliations

2020 Adjusted Cash from Ops Calculation ($M)[1]	BGE	ComEd	PECO	PHI	ExGen	Other	Exelon
Net cash flows provided by operating activities (GAAP)	$800	$1,250	$850	$900	$2,425	($350)	$5,875
Other cash from investing activities	-	-	-	-	($250)	-	($250)
Counterparty collateral activity	-	-	-	-	($675)	-	($675)
A/R Securitization	-	-	-	-	($500)	-	($500)
Collection of DPP[2]	-	-	-	-	$2,525	-	$2,525
Adjusted Cash Flow from Operations (Non-GAAP)	**$800**	**$1,250**	**$850**	**$900**	**$3,500**	**($350)**	**$6,950**

2020 Cash From Financing Calculation ($M)[1]	BGE	ComEd	PECO	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	$500	$1,025	$350	$575	($3,150)	$750	$50
Dividends paid on common stock	$250	$500	$350	$375	$1,550	($1,525)	$1,500
A/R Securitization	-	-	-	-	$500	-	$500
Financing Cash Flow (Non-GAAP)	**$725**	**$1,525**	**$700**	**$950**	**($1,075)**	**($750)**	**$2,050**

Exelon Total Cash Flow Reconciliation[1]	2020
GAAP Beginning Cash Balance	**$575**
Adjustment for Cash Collateral Posted	$925
Adjusted Beginning Cash Balance[3]	$1,500
Net Change in Cash (GAAP)[4]	($625)
Adjusted Ending Cash Balance[3]	$875
Adjustment for Cash Collateral Posted	($275)
GAAP Ending Cash Balance	**$600**

(1) All amounts rounded to the nearest $25M. Items may not sum due to rounding.
(2) Cash flows from the revolving accounts receivable financing arrangement (A/R Securitization) at ExGen are presented as cash flows from operating activities and cash flows from investing activities for GAAP, but as cash flows from operating activities for Adjusted (Non-GAAP) Cash Flows. The Collection of Deferred Purchase Price (DPP) in the table reflects the rounded amount of $2,518M for the nine months ended September 30, 2020, which is presented as cash flows from investing for GAAP.
(3) Adjusted Beginning and Ending cash balances reflect GAAP Beginning and End Cash Balances excluding counterparty collateral activity
(4) 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%.

Exelon.

GAAP to Non-GAAP Reconciliations

ExGen Adjusted O&M Reconciliation ($M)[1]	2020	2021
GAAP O&M	**$5,100**	**$4,700**
Decommissioning[2]	$75	$75
Byron, Dresden and Mystic 8/9 Retirements[3]	($425)	($25)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses[4]	($225)	($275)
O&M for managed plants that are partially owned	($400)	($425)
Other	($150)	-
Adjusted O&M (Non-GAAP)	**$4,000**	**$4,050**

Note: Items may not sum due to rounding
(1) All amounts rounded to the nearest $25M
(2) Reflects earnings neutral O&M
(3) 2020 includes $350M impact of accelerated earnings neutral O&M from the retirements of Byron and Dresden
(4) Reflects the direct cost of sales of certain businesses, which are included in Total Gross Margin*

Exelon.