Earnings Conference Call
Third Quarter 2021

November 3, 2021

Exelon®

Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties including, among others, those related to the timing, manner, tax-free nature, and expected benefits associated with the potential separation of Exelon's competitive power generation and customer-facing energy business from its six regulated electric and gas utilities. 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' 2020 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 19, Commitments and Contingencies; (2) the Registrants' Third Quarter 2021 Quarterly Report on Form 10-Q (to be filed on Nov. 3, 2021) 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 15, 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.
- ***Adjusted operating revenues*** exclude the Mark-to-Market impact of economic hedging activities due to the volatility and unpredictability of the future changes to power prices
- ***Adjusted purchased power and fuel*** excludes the Mark-to-Market impact of economic hedging activities due to the volatility and unpredictability of the future changes to power prices

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

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Non-GAAP Financial Measures Continued

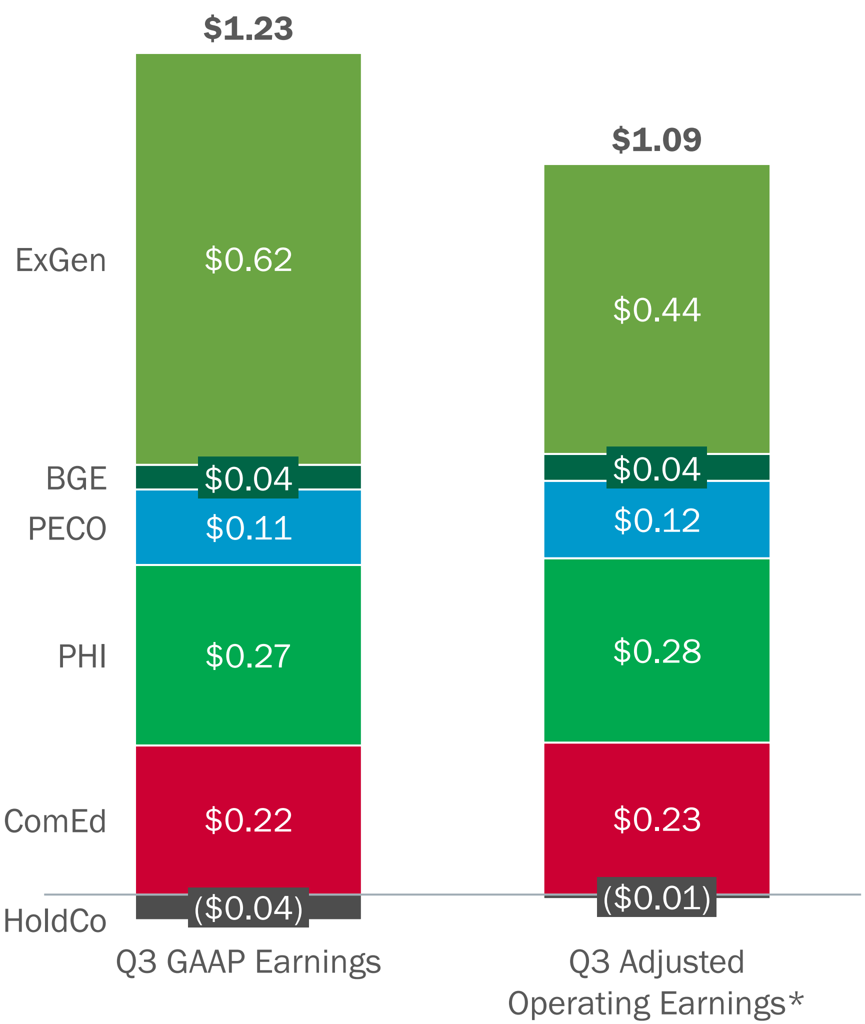
This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of Exelon's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business. 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 32 of this presentation.

Third Quarter Results

Q3 2021 EPS Results



Q3 2021 Highlights/Key Developments

- Passage of clean energy legislation in Illinois
- Announced continued operation of Byron and Dresden nuclear stations
- Completed the acquisition of EDF's ownership stake of CENG nuclear plants
- FERC approved separation of utility and generation businesses
- Awarded DOE grant to support hydrogen production project at Nine Mile Point nuclear station
- Delmarva DE received order in its electric distribution rate case
- Pepco filed 5-Year Action Plan to support D.C.'s clean energy and climate goals
- Exelon launched $36 million Racial Equity Capital Fund and $3 million Exelon HBCU Corporate Scholars Program
- ComEd, PECO and BGE named to Site Selection Magazine's annual list of top 20 utilities in economic development

Note: Amounts may not sum due to rounding

Operating Highlights

Exelon Utilities Operational Metrics

Operations	Metric	YTD 2021			
		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**		

- Reliability performance was strong across the utilities:
  - All utilities delivered top decile SAIFI performance, and ComEd scored in the top decile in CAIDI
- Each utility continued to deliver on key customer operations metrics:
  - BGE, ComEd and PECO achieved top decile performance in customer satisfaction
  - PHI recorded top decile performance in abandon rate
- BGE, PECO and PHI remained top decile in gas odor response
- Focused on improving safety at BGE, ComEd and PECO

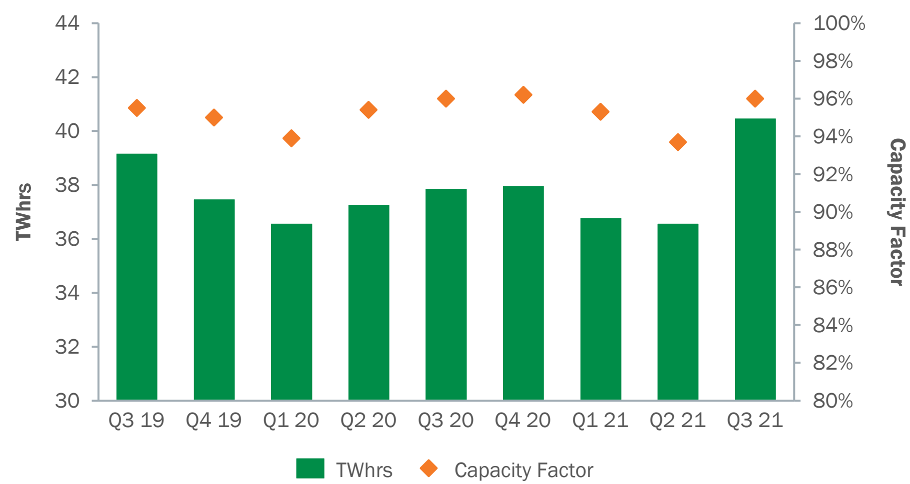
Quartile

Q1	Q2
Q3	Q4

Exelon Generation Operational Performance

Exelon Nuclear Fleet(2)

- Best in class performance across our Nuclear fleet:
  - Q3 2021 Nuclear Capacity Factor: 96.0%
  - Owned and operated Q3 2021 production of 40.5 TWh



Fossil and Renewable Fleet

- Q3 2021 Power Dispatch Match: 99.4%
- Q3 2021 Wind/Solar Energy Capture: 95.8%

(1) 2.5 Beta SAIFI is YE projection
(2) Excludes Salem. Nuclear operations prior to Q3 2021 reflect Exelon's 50.01% ownership share of the CENG Joint Venture. Reflects 100% ownership of CENG beginning August 7, 2021.

Progress on Separation

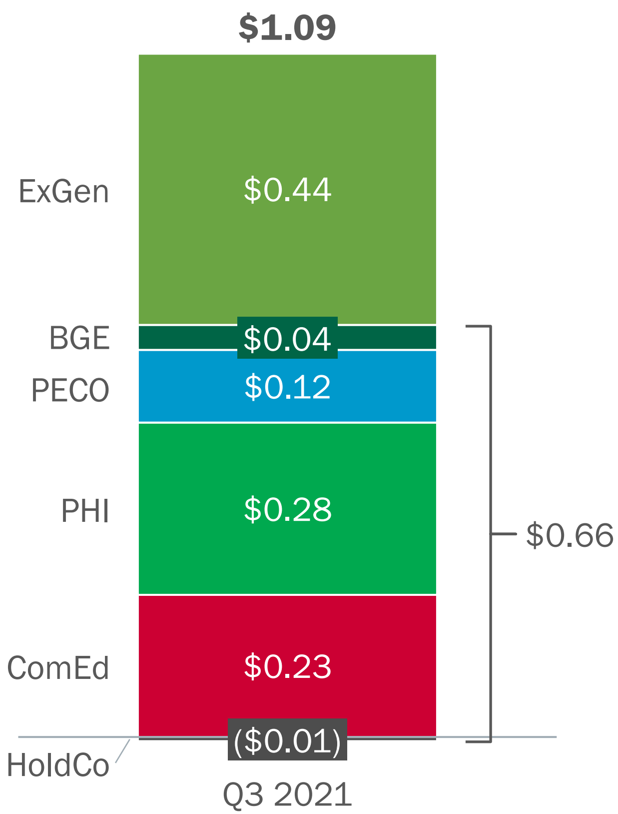
- Named CEOs and direct reports, including CFOs, for Exelon and Constellation
- Separation planning and preparation continues
- Below is the current status of the regulatory filings:

Commission	Application Filing	Key Regulatory Milestones	Approved?
New York Public Service Commission (NY PSC) (Case No. 21-E-0130)	February 25, 2021	• Comments/intervention were due June 8, 2021 • Notice of Impending Settlement Negotiations issued on October 25, 2021	
Federal Energy Regulatory Commission (FERC) (Docket No. EC21-57)	February 25, 2021	• Initial comments/intervention were due March 18, 2021 • Subsequent comments/intervention were due May 13, 2021 • Approved on August 24, 2021	✓
Nuclear Regulatory Commission (NRC)	February 25, 2021	• Comments were due June 23, 2021 • Deadline to request hearing closed July 12, 2021(1) • Updated financials and decommissioning funding status submitted September 29, 2021 • Estimated approval by November 30, 2021	

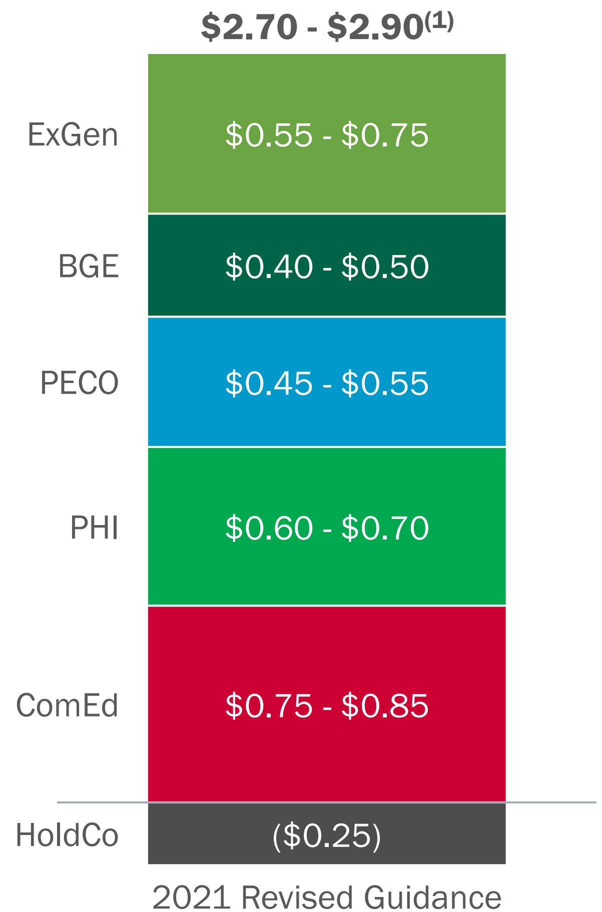
(1) Hearing requests may still be pending and resolved later, but approval will be subject to modification by Commission through hearing process

Third Quarter Adjusted Operating Earnings* Results and Full Year Adjusted Operating Earnings* Guidance

Q3 2021 Adjusted Operating EPS* Results



2021 Adjusted Operating EPS* Guidance



Narrowing 2021 Adjusted Operating Earnings* to $2.70 - $2.90 per share[1]

Note: Amounts may not sum due to rounding

(1) 2021 earnings guidance based on expected average outstanding shares of 980M

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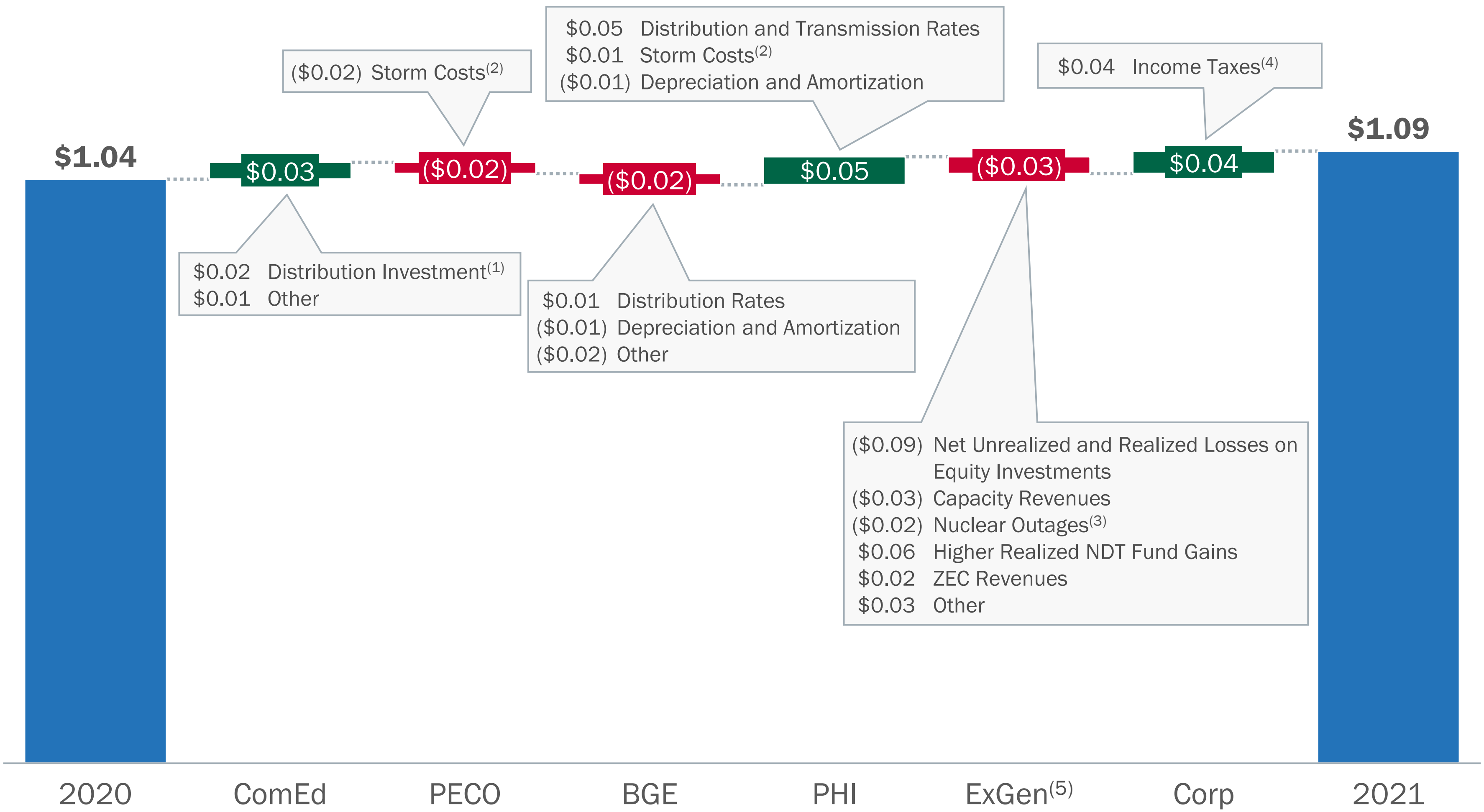
Q3 2021 QTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

(1) Reflects higher rate base and higher allowed electric distribution ROE due to an increase in treasury rates

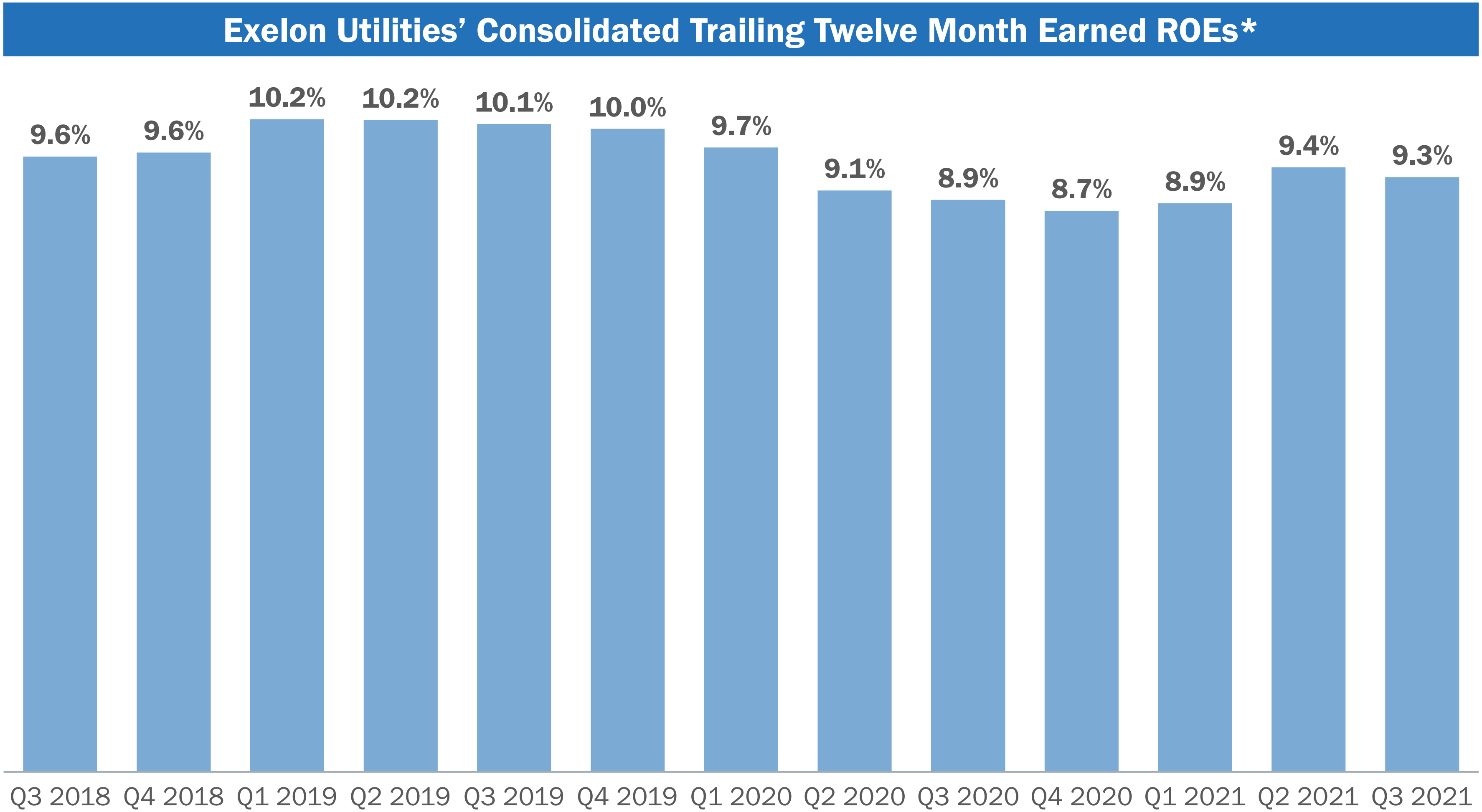
(2) At PECO, primarily reflects a net increase in storm costs resulting from storms in the third quarter of 2021, partially offset by the absence of the August 2020 storms, net of tax repairs. At PHI, primarily reflects the absence of costs in 2021 due to the August 2020 storms.

(3) Reflects revenue and operating and maintenance expense impacts of higher nuclear outage days in 2021, excluding Salem

(4) Reflects the reversal of part of the tax expense recorded in the first quarter due to the loss before income taxes at ExGen resulting from the February 2021 extreme cold weather event

(5) Drivers reflect CENG ownership at 100%

Exelon Utilities Trailing Twelve Month Earned ROEs*



Exelon Utilities' Consolidated TTM Earned ROE* remains within our 9-10% targeted range

Note: Represents the twelve-month periods ending September 30, 2018-2021, June 30, 2019-2021, March 31, 2019-2021 and December 31, 2018-2020. Earned ROEs* represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Electric Transmission).

Exelon Utilities' Distribution Rate Case Updates

Rate Case Schedule and Key Terms

	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Revenue Requirement	Requested ROE / Equity Ratio	Expected Order
ACE	SA FO												$41.0M(1,2)	9.60% / 50.21%	Jul 14, 2021
DPL DE Electric			FO										$13.5M(1,3)	9.60% / 50.37%	Sep 15, 2021(4)
PECO Electric	RT	EH	SA			FO							$132.0M(1)	10.95% / 53.41%	Dec 2021
ComEd	RT		EH	IB RB		FO							$45.8M(1,5)	7.36% / 48.70%	Dec 2021
DPL MD			CF			IT RT	EH	IB	FO				$28.8M(1)	10.10% / 50.61%	Mar 30, 2022

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 (ICC), Maryland Public Service Commission (MDPSC), Pennsylvania Public Utility Commission (PAPUC), Delaware Public Service Commission (DPSC), Public Service Commission of the District of Columbia (DCPSC), and New Jersey Board of Public Utilities (NJBPU) 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) Reflects annual gross incremental revenue requirement (before offsets), effective January 1, 2022. Pro-rated gross incremental revenue requirement for 2021 (July 14, 2021 through December 31, 2021) is approximately $16M and will be offset in customer rates by $16M of certain accelerated tax benefits.
(3) Requested revenue requirement excludes the transfer of $3.2M 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.
(4) The DPSC issued a minute order on September 15, 2021 with new rates effective on September 17, 2021. The final order with further justification is expected shortly.
(5) Revenue requirement in initial filing was an increase of $51.2M. Through the discovery period in the current proceeding, ComEd agreed to ~($5.3M) in adjustments to limit issues in the case.

Exelon Utilities Path to Clean: Advancing Energy Efficiency

Promoting the Expansion of Energy Efficiency Offerings

- Working with stakeholders to expand business, residential and low-income offerings that are needed to achieve state targets
- All six utility jurisdictions have voluntary or mandated targets to increase annual energy savings

Incentivizing Efficiency Upgrades

- Energy audits assess customer efficiency and recommend usage reduction remediation measures
- Offer discounts, rebates, and other incentives to install higher-efficiency equipment and controls

Developing Innovative Solutions For Customers

- Developing strategies to deploy next generation technologies and explore business models through research & development and other pilot programs
- Market development initiatives grow the diversity of our partners and vendors

Reducing Customer Energy Consumption

- Helped our customers save **22.3 million MWhs of electricity** in 2020
- Behavioral programs notify customers about atypical energy use and available load curtailment programs

Supporting Customer Affordability

- Hourly pricing and smart usage rewards programs help customers manage costs during peak-demand hours

Driving Emissions Reductions

- ComEd, BGE and PECO were recognized as top utilities in the nation for efficiency by the American Council for an Energy-Efficient Economy in 2020
- Avoided **8.1 million mtCO$_2$e** emissions in 2020

Exelon Utilities' energy efficiency investments are helping our customers and communities reduce emissions and save money

Exelon Generation: Gross Margin* Update

Gross Margin Category ($M)[1]	September 30, 2021 2021	Change from June 30, 2021 2021
Open Gross Margin*[2] (including South, West, New England, Canada hedged gross margin)	$5,850	$1,600
Capacity and ZEC Revenues[2]	$1,900	$100
Mark-to-Market of Hedges[2,3]	$(1,100)	$(1,000)
Power New Business / To Go	$50	$(200)
Non-Power Margins Executed	$400	$50
Non-Power New Business / To Go	$100	$(50)
Total Gross Margin* (Excluding Impact of February Weather Event)[4]	**$7,200**	**$500**
Estimated Gross Margin Impact of February Weather Event[5]	$(950)	-
Total Gross Margin*	**$6,250**	**$500**

Recent Developments

- 2021 Total Gross Margin* is projected to be $500M higher primarily due to acquisition of EDF's ownership stake of CENG nuclear plants and the reversal of the Byron and Dresden retirements
  - Executed $200M of Power New Business and $50M of Non-Power New Business

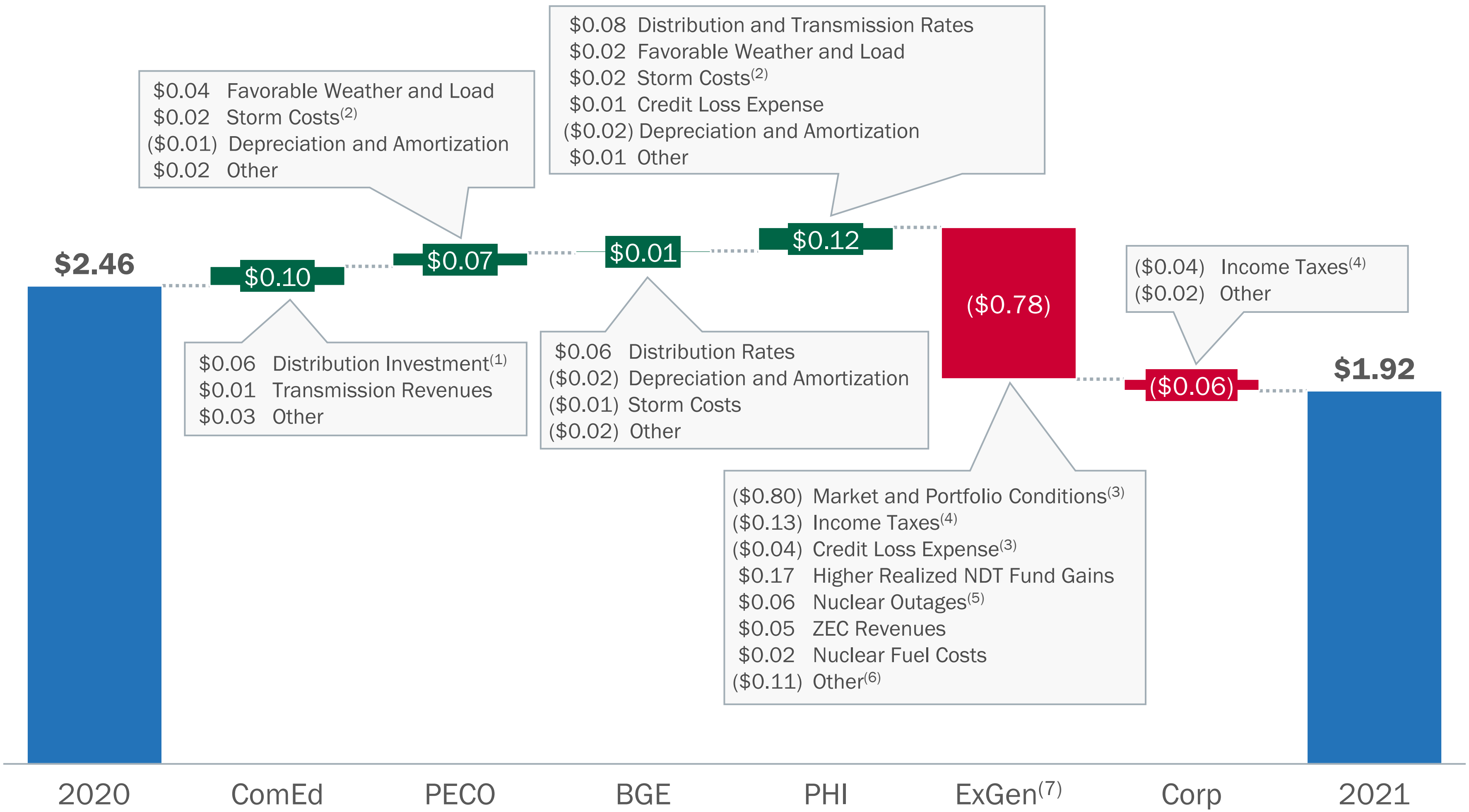
(1) Gross margin* categories rounded to nearest $50M
(2) Reflects Exelon's 50.01% ownership share of CENG Joint venture from January 1 to August 6, 2021 and Exelon's full ownership share beginning August 7, 2021
(3) Mark-to-Market of Hedges assumes mid-point of hedge percentages
(4) Based on September 30, 2021 market conditions
(5) Reflects the midpoint of the current gross margin estimate of $(850)-$(1,050)M across our portfolios. Excludes bad debt and other P&L offsets.

2021 Business Priorities and Commitments

- Maintain industry-leading operational excellence
- Prepare for separation of businesses
- Meet or exceed our financial commitments
- Effectively deploy ~$6.6B of utility capex
- Ensure timely recovery on investments to enable customer benefits
- Support enactment of clean energy policies
- Continued demonstration of corporate responsibility

Additional Disclosures

Q3 2021 YTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

(1) Reflects higher rate base and higher allowed electric distribution ROE due to an increase in treasury rates

(2) At PECO, primarily reflects a net decrease in storm costs resulting from the absence of the June and August 2020 storms, net of tax repairs, partially offset by storm costs in 2021. At PHI, primarily reflects the absence of costs in 2021 due to the August 2020 storms.

(3) Primarily reflects the impacts of the February 2021 extreme cold weather event

(4) ($0.05) at ExGen and the ($0.04) at Corp relate to timing of tax expense driven primarily by the loss before income taxes at ExGen in the first quarter due to the February 2021 extreme cold weather event. These timing impacts will continue to reverse by the end of the year. ($0.07) at ExGen reflects the absence of a prior year one-time tax settlement.

(5) Reflects the revenue and operating and maintenance expense impacts of lower nuclear outage days in 2021, including Salem

(6) Primarily reflects the elimination of activity attributable to noncontrolling interest of ($0.16), primarily for CENG prior to Generation's acquisition of Electricite de France SA's (EDF's) interest in CENG on August 6, 2021

(7) Drivers reflect CENG ownership at 100%

Constellation Technology Ventures' Portfolio

Investing in venture stage energy technology companies(1) that can provide new solutions to Exelon and its customers

PROTERRA Electric buses for public and private mass transit	DEMAND Q HVAC optimization for SMB and C&I	chargepoint EV charging network and service equipment	stem Energy storage systems and controls
bidgely Residential load disaggregation platform	novo Battery monitoring and management software	PosiGen Residential PV and EE for low-to-middle income homeowners	sparkfund EE financing and building optimization for SMB and C&I
XL Class 2-6 HEV and PHEV fleet electrification	PRECISIONHAWK Unmanned aerial vehicle software control platform	measurabl Building sustainability reporting platform	Level10 Energy Renewable PPA Marketplace
	vutility Non-invasive energy data collection and reporting		

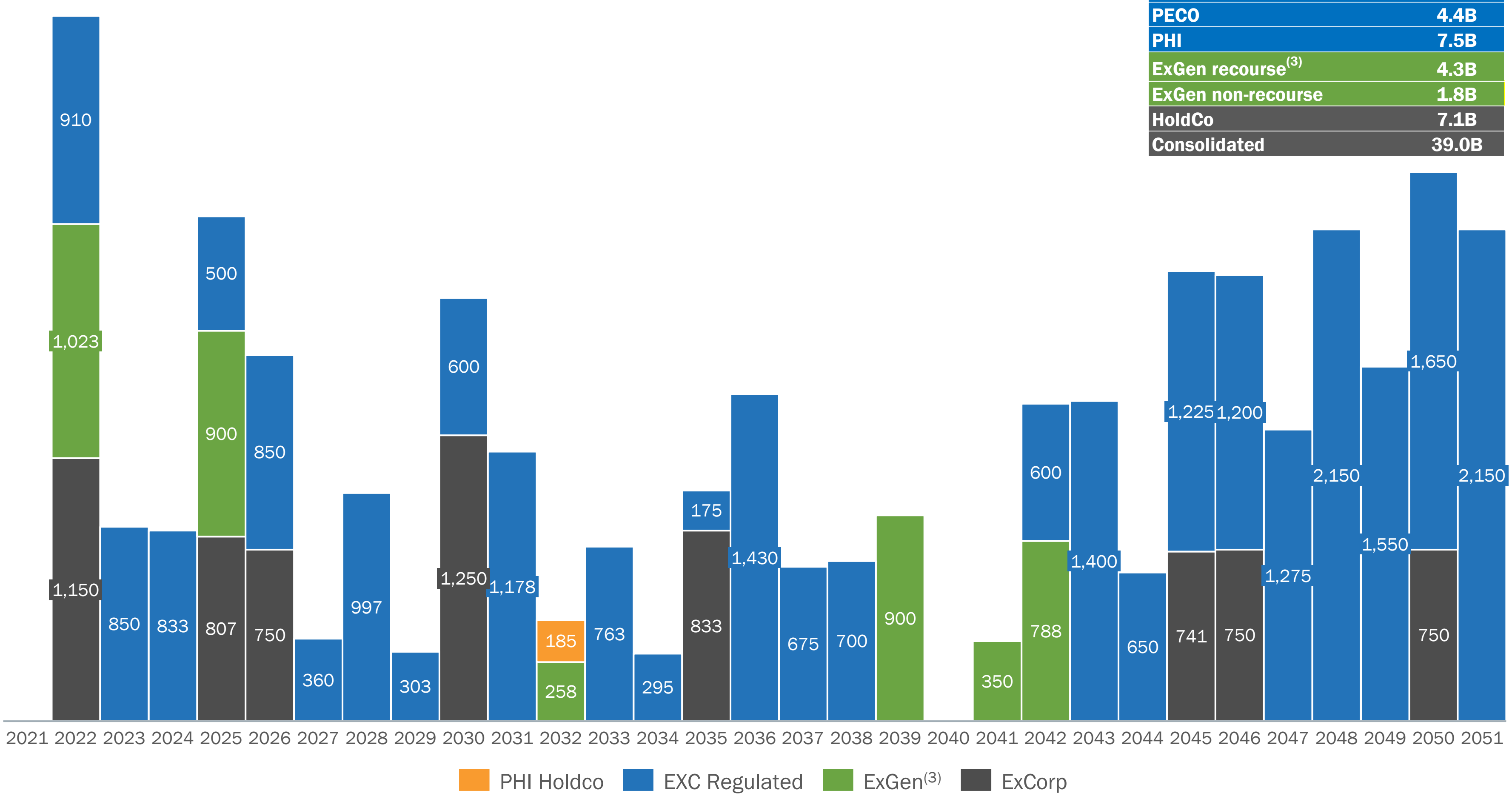
Note: Constellation's active technology investments can be found at http://technologyventures.constellation.com/; reflects current portfolio as of September 30, 2021

(1) Green boxes reflect companies that have executed Initial Public Offerings (IPOs) or merger transactions with Special Purpose Acquisition Companies (SPACs). XL Fleet (SPAC) transaction closed in Q4 2020. ChargePoint (SPAC) transaction closed in Q1 2021. STEM (SPAC) and Proterra (SPAC) transactions closed in Q2 2021.

Exelon Long-Term Debt Maturity Profile[1,2]

As of 9/30/2021
($M)

LT Debt Balances (as of 9/30/21)[1,2]	
BGE	4.0B
ComEd	10.0B
PECO	4.4B
PHI	7.5B
ExGen recourse[3]	4.3B
ExGen non-recourse	1.8B
HoldCo	7.1B
Consolidated	39.0B



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 2021 10-Q GAAP financials, which include items listed in footnote 1
(3) Includes $258M of legacy CEG debt in 2032

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ACE Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	ER20120746
Test Year	January 1, 2020 – December 31, 2020
Test Period	12 months actual
Common Equity Ratio	50.21%
Rate of Return	ROE: 9.60%; ROR: 6.99%
Rate Base (Adjusted)	$1.8B
Revenue Requirement Increase	$41.0M[1,2]
Residential Total Bill % Increase	3.3%

Notes

- December 9, 2020, ACE filed a distribution base rate case with the New Jersey Board of Public Utilities (NJBPU) to increase distribution base rates
- July 14, 2021, the NJBPU approved the settlement with new rates effective on January 1, 2022
- No rate increases to customers until January 1, 2022 due to the acceleration of certain tax benefits

Detailed Rate Case Schedule

	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Filed rate case	▲ 12/9/2020												
Settlement agreement								▲ 7/2/2021					
Commission order								▲ 7/14/2021					

(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 annual gross incremental revenue requirement (before offsets), effective January 1, 2022. Pro-rated gross incremental revenue requirement for 2021 (July 14, 2021 through December 31, 2021) is approximately $16M and will be offset in customer rates by $16M of certain accelerated tax benefits.

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
Common Equity Ratio	50.37%
Rate of Return	ROE: 9.60%; ROR: 6.80%
Rate Base (Adjusted)	$900.0M
Revenue Requirement Increase	$13.5M[1,2]
Residential Total Bill % Increase	2.4%

Notes

- March 6, 2020, Delmarva Power filed an application with the Delaware Public Service Commission (DPSC) seeking an increase in electric distribution base rates
- A partial settlement agreement, primarily on customer care issues, was filed with the DPSC on February 2, 2021
- September 15, 2021, the DPSC issued a minute order with new rates effective on September 17, 2021. The final order with further justification is expected shortly.

Detailed Rate Case Schedule

	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Filed rate case		3/6/2020																			
Intervenor testimony								9/9/2020													
Rebuttal testimony									10/26/2020												
Evidentiary hearings													2/10/2021 - 2/15/2021								
Initial briefs														3/17/2021							
Reply briefs																5/12/2021					
Commission order																				9/15/2021	

(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 $3.2M 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.

PECO (Electric) Distribution Rate Case Filing

	Rate Case Filing Details
Docket No.	R-2021-3024601
Test Year	January 1, 2022 – December 31, 2022
Test Period	12 Months Budget
Proposed Common Equity Ratio	53.41%
Proposed Rate of Return	ROE: 10.95%; ROR: 7.68%
Proposed Rate Base (Adjusted)	$6,386M
Revenue Requirement Increase	$132.0M(1)
Residential Total Bill % Increase	6.6%

Notes

- March 30, 2021, PECO filed a general base rate request with the Pennsylvania Public Utility Commission (PAPUC) seeking an increase in electric distribution base rates
- Rate increase amount is driven by continued investments in infrastructure that will enhance the local electric grid as well as to enable the advancement of clean technologies
- September 15, 2021, PECO filed a Joint Petition for Settlement of Rate Investigation, which included a revenue requirement increase of $132M, but no stipulation on ROE and Equity Ratio

Detailed Rate Case Schedule

	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Filed rate case	3/30/2021											
Intervenor testimony				6/28/2021								
Rebuttal testimony					7/22/2021							
Evidentiary hearings						8/11/2021						
Settlement agreement							9/15/2021					
Commission order expected										12/2021		

(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
Docket No.	21-0367
Test Year	January 1, 2020 – December 31, 2020
Test Period	2020 Actual Costs + 2021 Projected Plant Additions
Proposed Common Equity Ratio	48.70%
Proposed Rate of Return	ROE: 7.36%; ROR: 5.72%
Proposed Rate Base (Adjusted)	$13,035M
Requested Revenue Requirement Increase	$45.8M[1,2]
Residential Total Bill % Increase	0.2%

Notes

- April 16, 2021, ComEd filed its annual distribution formula rate update with the Illinois Commerce Commission (ICC) seeking a $51.2M increase to distribution base rates
- Rate increase amount is driven by continued investments in infrastructure that will enhance the reliability of the grid and enable the advancement of clean technologies and renewable energy
- A final order is expected in early December

Detailed Rate Case Schedule

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Filed rate case	4/16/2021											
Intervenor testimony			6/30/2021									
Rebuttal testimony				7/28/2021								
Evidentiary hearings						9/13/2021						
Initial briefs							10/1/2021					
Reply briefs							10/15/2021					
Commission order expected									12/2021			

(1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings
(2) Revenue requirement in initial filing was an increase of $51.2M. Through the discovery period in the current proceeding, ComEd agreed to ~($5.3M) in adjustments to limit issues in the case.

Delmarva MD Distribution Rate Case Filing

	Rate Case Filing Details
Case No.	9670
Test Year	October 1, 2020 – September 30, 2021
Test Period	9 months actual + 3 months estimated
Proposed Common Equity Ratio	50.61%
Proposed Rate of Return	ROE: 10.10%; ROR: 6.90%
Proposed Rate Base (Adjusted)	$930.1M
Requested Revenue Requirement Increase	$28.8M(1)
Residential Total Bill % Increase	5.0%

Notes

- September 1, 2021, Delmarva Power filed an application with the Maryland Public Service Commission (MDPSC) seeking an increase in electric distribution base rates
- Request is driven by $18.3M of higher depreciation expense related to the Company's updated depreciation study and continued investments in electric distribution system to maintain and increase reliability and customer service

Detailed Rate Case Schedule

	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
Filed rate case		9/1/2021											
Intervenor testimony					12/2/2021								
Rebuttal testimony					12/23/2021								
Evidentiary hearings						1/19/2022 - 1/24/2022							
Initial briefs							2/9/2022						
PULJ proposed order expected(2)							2/28/2022						
Commission order expected								3/30/2022					

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

Exelon Generation Disclosures

September 30, 2021

Portfolio Management Strategy

Strategic Policy Alignment

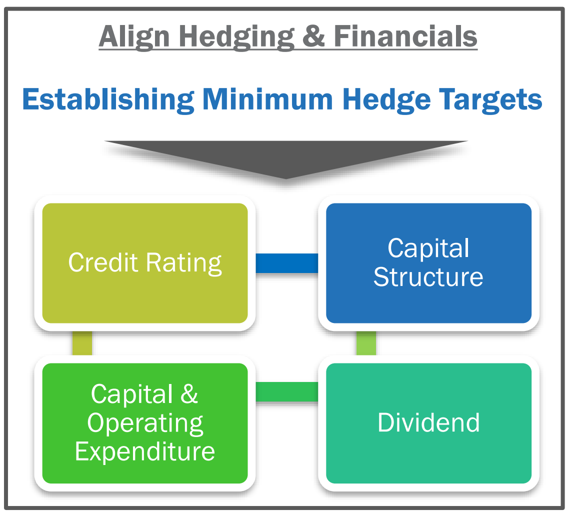
- Aligns hedging program with financial policies and financial outlook
  - Establish minimum hedge targets to meet financial objectives of the company (dividend, credit rating)
  - Hedge enough commodity risk to meet future cash requirements under a stress scenario

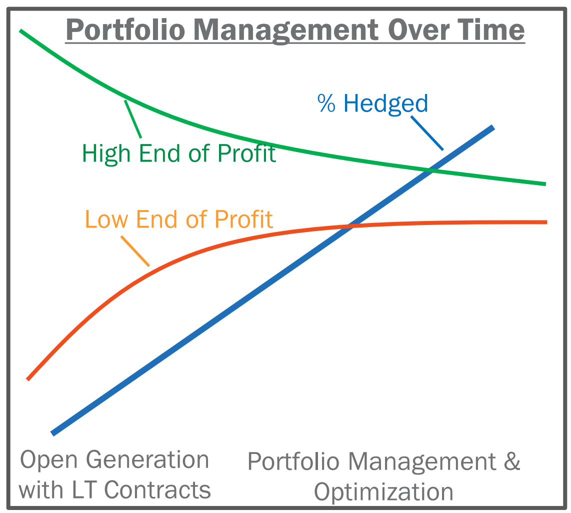
Three-Year Ratable Hedging

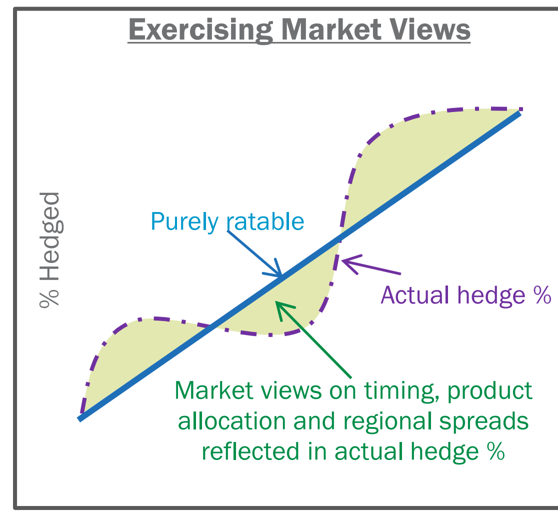
- Ensure stability in near-term cash flows and earnings
  - Disciplined approach to hedging
  - Tenor aligns with customer preferences and market liquidity
  - Multiple channels to market that allow us to maximize margins
  - Large open position in outer years to benefit from price upside

Bull / Bear Program

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







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

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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, 2021 2021
Open Gross Margin (including South, West, New England & Canada hedged GM)*[2]	$5,850
Capacity and ZEC Revenues[2]	$1,900
Mark-to-Market of Hedges[2,3]	$(1,100)
Power New Business / To Go	$50
Non-Power Margins Executed	$400
Non-Power New Business / To Go	$100
Total Gross Margin* (Excluding Impact of February Weather Event)[4]	**$7,200**
Estimated Gross Margin Impact of February Weather Event[5]	$(950)
Total Gross Margin*	**$6,250**

Reference Prices[4,6]	2021
Henry Hub Natural Gas ($/MMBtu)	$3.94
Midwest: NiHub ATC prices ($/MWh)	$36.10
Mid-Atlantic: PJM-W ATC prices ($/MWh)	$39.21
ERCOT-N ATC Spark Spread ($/MWh) *HSC Gas, 7.2HR, $2.50 VOM*	$87.14
New York: NY Zone A ($/MWh)	$31.32

(1) Gross margin* categories rounded to nearest $50M
(2) Reflects Exelon's 50.01% ownership share of CENG Joint venture from January 1 to August 6, 2021 and Exelon's full ownership share beginning August 7, 2021
(3) Mark-to-Market of Hedges assumes mid-point of hedge percentages
(4) Based on September 30, 2021 market conditions
(5) Reflects the midpoint of the current gross margin estimate of $(850)-$(1,050)M across our portfolios. Excludes bad debt and other P&L offsets.
(6) Reflects full year prices based on Exelon's portfolio hedging strategy

ExGen Disclosures

September 30, 2021

Generation and Hedges	2021
Expected Generation (GWh)[1]	**183,400**
Midwest	95,000
Mid-Atlantic[2]	51,500
ERCOT	16,300
New York[2]	20,600
% of Expected Generation Hedged[3]	**96%-99%**
Midwest	96%-99%
Mid-Atlantic[2]	95%-98%
ERCOT	94%-97%
New York[2]	95%-98%
Effective Realized Energy Price ($/MWh)[4]	
Midwest	$27.50
Mid-Atlantic[2]	$34.50
New York[2]	$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 13 refueling outages in 2021 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factor of 94.5% in 2021 at Exelon-operated nuclear plants, at ownership.
(2) Reflects Exelon's 50.01% ownership share of CENG Joint venture from January 1 to August 6, 2021 and Exelon's full ownership share beginning August 7, 2021
(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.

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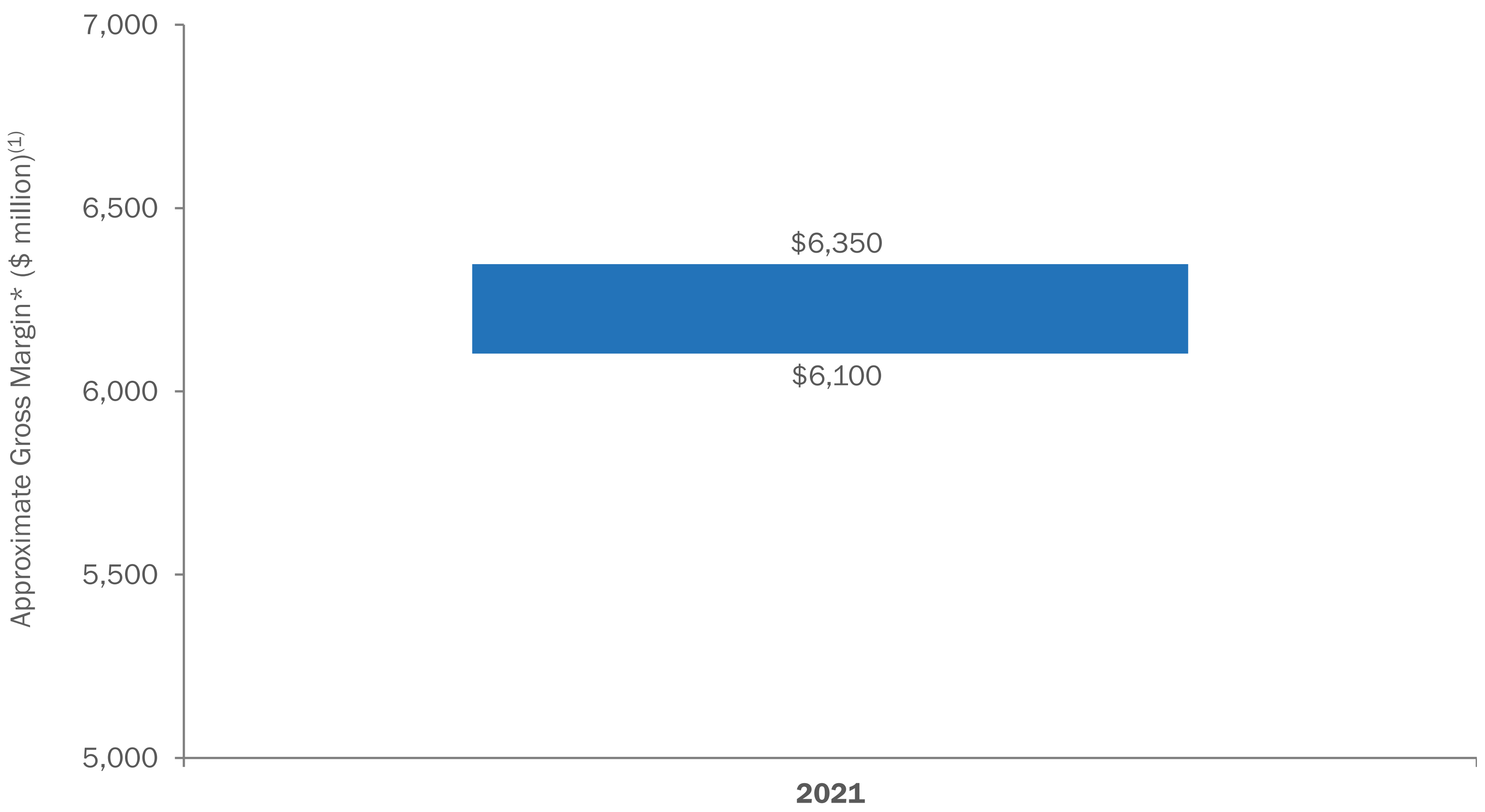
ExGen Hedged Gross Margin* Sensitivities

September 30, 2021

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

(1) Based on September 30, 2021 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; reflects Exelon's 50.01% ownership share of CENG Joint venture from January 1 to August 6, 2021 and Exelon's full ownership share beginning August 7, 2021

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* range is based upon an internal simulation model and are subject to change based upon market inputs, future transactions and potential modeling changes; the price distributions that generate this range are calibrated to market quotes for power, fuel, load following products, and options as of September 30, 2021. Gross Margin* Upside/Risk based on commodity exposure which includes open generation and all committed transactions.

Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in $M)[1]	2021
Adjusted Operating Revenues*[2,3]	**$19,875**
Adjusted Purchased Power and Fuel*[2,3]	$(13,175)
Other Revenues[4]	$(175)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses	$(275)
Total Gross Margin* (Non-GAAP)	**$6,250**

Key ExGen Modeling Inputs (in $M)[1,5]	2021
Other[6]	$350
Adjusted O&M*[7]	$(4,075)
Taxes Other Than Income (TOTI)[8]	$(350)
Depreciation & Amortization*	$(1,025)
Interest Expense	$(300)
Effective Tax Rate	**25.0%**

(1) All amounts rounded to the nearest $25M
(2) Reflects Exelon's 50.01% ownership share of CENG from January 1 to August 6, 2021 and Exelon's full ownership share beginning August 7, 2021
(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) O&M, TOTI and Depreciation & Amortization reflect Exelon's 50.01% ownership share of CENG Joint venture from January 1 to August 6, 2021 and Exelon's full ownership share beginning August 7, 2021
(6) Other reflects Other Revenues excluding gross receipts tax revenues, includes nuclear decommissioning trust fund earnings from unregulated sites, includes the minority interest in ExGen Renewables JV, and unrealized gains or losses from equity investments
(7) 2021 Adjusted O&M* includes $175M of non-cash expense related to the increase in the ARO liability due to the passage of time and a preliminary estimate of bad debt associated with the February weather event that is subject to change
(8) 2021 TOTI excludes gross receipts tax of $100M

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Appendix

Reconciliation of Non-GAAP Measures

Q3 QTD GAAP EPS Reconciliation

Three Months Ended September 30, 2021	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
2021 GAAP Earnings (Loss) Per Share	**$0.22**	**$0.11**	**$0.04**	**$0.27**	**$0.62**	**($0.04)**	**$1.23**
Mark-to-market impact of economic hedging activities	-	-	-	-	(0.58)	0.01	(0.57)
Unrealized losses related to NDT funds	-	-	-	-	0.06	-	0.06
Asset impairments	-	-	-	-	0.03	-	0.03
Plant retirements and divestitures	-	-	-	-	0.22	-	0.22
Cost management program	-	-	-	-	-	-	0.01
COVID-19 direct costs	-	-	-	-	-	-	0.01
Asset retirement obligation	-	-	-	-	(0.04)	-	(0.04)
Acquisition related costs	-	-	-	-	0.01	-	0.01
Planned separation costs	-	-	-	-	0.01	-	0.03
Costs related to suspension of contractual offset	-	-	-	-	0.11	-	0.11
Income tax-related adjustments	-	-	-	-	-	0.02	0.02
Noncontrolling interests	-	-	-	-	(0.02)	-	(0.02)
2021 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.23**	**$0.12**	**$0.04**	**$0.28**	**$0.44**	**($0.01)**	**$1.09**

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, 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.

Q3 YTD GAAP EPS Reconciliation

Nine Months Ended September 30, 2021	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
2021 GAAP Earnings (Loss) Per Share	**$0.62**	**$0.39**	**$0.30**	**$0.55**	**($0.25)**	**($0.26)**	**$1.34**
Mark-to-market impact of economic hedging activities	-	-	-	-	(0.95)	0.01	(0.94)
Unrealized gains related to NDT funds	-	-	-	-	(0.03)	-	(0.03)
Asset impairments	-	-	-	-	0.41	-	0.41
Plant retirements and divestitures	-	-	-	-	0.88	-	0.88
Cost management program	-	-	-	-	0.01	-	0.01
Change in environmental liabilities	-	-	-	-	0.01	-	0.01
COVID-19 direct costs	-	-	-	-	0.02	-	0.02
Asset retirement obligation	-	-	-	-	(0.04)	-	(0.04)
Acquisition related costs	-	-	-	-	0.02	-	0.02
ERP system implementation costs	-	-	-	-	0.01	-	0.01
Planned separation costs	0.01	-	-	0.01	0.02	0.01	0.05
Costs related to suspension of contractual offset	-	-	-	-	0.15	-	0.15
Income tax-related adjustments	-	-	-	-	-	0.02	0.02
Noncontrolling interests	-	-	-	-	0.02	-	0.02
2021 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.63**	**$0.40**	**$0.30**	**$0.56**	**$0.26**	**($0.23)**	**$1.92**

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

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Q3 YTD GAAP EPS Reconciliation (continued)

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.

Projected GAAP to Operating Adjustments

- **Exelon's projected 2021 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 and divestitures;
  - Certain costs incurred to achieve cost management program savings;
  - Direct costs related to the novel coronavirus (COVID-19) pandemic;
  - Certain acquisition-related costs;
  - Costs related to a multi-year Enterprise Resource Program (ERP) system implementation;
  - Costs related to the planned separation;
  - Costs related to the impact of suspension of contractual offset for the Byron units beginning in the second quarter of 2021 through September 15, 2021;
  - Asset retirement obligations;
  - Adjustment to deferred income taxes as a result of changes in forecasted apportionment;
  - Other items not directly related to the ongoing operations of the business; and
  - Generation's noncontrolling interest related to exclusion items.

GAAP to Non-GAAP Reconciliations

Consolidated EU Operating TTM ROE Reconciliation ($M)	Q3 2021	Q2 2021	Q1 2021
Net Income (GAAP)	$2,243	$2,214	$1,841
Operating Exclusions	$42	$36	$249
Adjusted Operating Earnings	$2,284	$2,250	$2,090
Average Equity	$24,651	$23,882	$23,598
Operating (Non-GAAP) TTM ROE (Adjusted Operating Earnings/Average Equity)	**9.3%**	**9.4%**	**8.9%**

Consolidated EU Operating TTM ROE Reconciliation ($M)	Q4 2020	Q3 2020	Q2 2020	Q1 2020
Net Income (GAAP)	1,737	1,747	$1,728	$2,060
Operating Exclusions	246	243	$254	$31
Adjusted Operating Earnings	1,984	1,990	$1,982	$2,091
Average Equity	22,690	22,329	$21,885	$21,502
Operating (Non-GAAP) TTM ROE (Adjusted Operating Earnings/Average Equity)	**8.7%**	**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
Net Income (GAAP)	$1,836	$1,770
Operating Exclusions	$32	$40
Adjusted Operating Earnings	$1,869	$1,810
Average Equity	$19,367	$18,878
Operating (Non-GAAP) TTM ROE (Adjusted Operating Earnings/Average Equity)	**9.6%**	**9.6%**

Note: Represents the twelve-month periods ending September 30, 2018-2021, June 30, 2019-2021, March 31, 2019-2021 and December 31, 2018-2020. Earned ROEs* represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Electric Transmission).

GAAP to Non-GAAP Reconciliations

ExGen Adjusted O&M Reconciliation ($M)[1]	2021
GAAP O&M	**$4,600**
Decommissioning[2]	$25
Byron and Dresden[3]	$575
Asset Impairments[4]	($525)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses[5]	($275)
O&M for managed plants that are partially owned	($250)
Other	($75)
Adjusted O&M (Non-GAAP)	**$4,075**

Note: Items may not sum due to rounding
(1) All amounts rounded to the nearest $25M
(2) Reflects earnings neutral O&M
(3) Includes $500M of accelerated earnings neutral O&M associated with the decision to early retire Byron and Dresden that cannot be reversed. The remaining amount primarily reflects the reversal of one-time charges resulting from the previous decision to retire Byron and Dresden.
(4) Reflects an impairment in the New England asset group, an impairment recorded as a result of the agreement to sell the Albany Green Energy biomass facility, and an impairment of a wind project
(5) Reflects the direct cost of sales of certain businesses, which are included in Total Gross Margin*