

# Earnings Conference Call

## 1<sup>st</sup> Quarter 2016

May 6, 2016



# Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC (PHI), Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2015 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 23; (2) PHI's 2015 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 16; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this presentation. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

# Combined Company at a Glance



## EXC

Exelon is headquartered in Chicago and trades on the NYSE under EXC.

Exelon is the #1 utility company on the FORTUNE 500.



Exelon is America's #1 zero-carbon nuclear energy provider.

## \$34.5B

Operating revenue in 2015



Presence in 48 states

Exelon is a FORTUNE 150 company that works in every stage of the energy business: power generation, competitive energy sales, transmission and delivery.



## 10M

Electric and natural gas utility customers

Exelon's Constellation business serves approx. 2 million residential, public sector and business customers.



Exelon was named to Fortune magazine's 2015 list of the "World's Most Admired Companies."

## 32,700

Megawatts of total power generation



## 19,500

Megawatts of nuclear generation

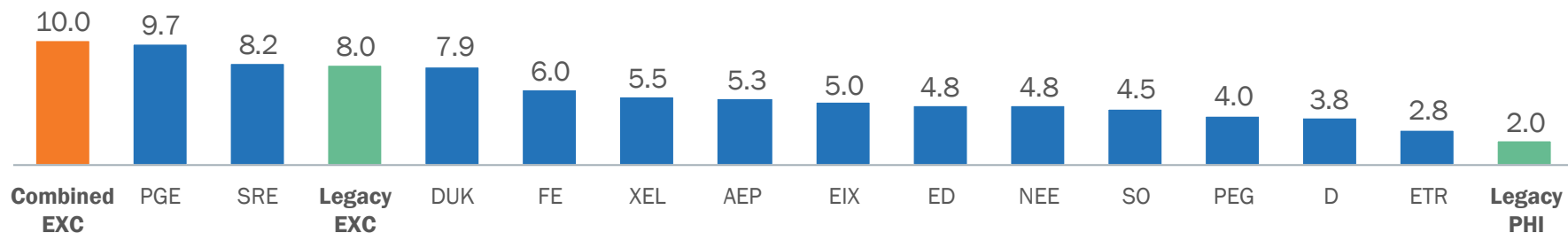


## \$37M

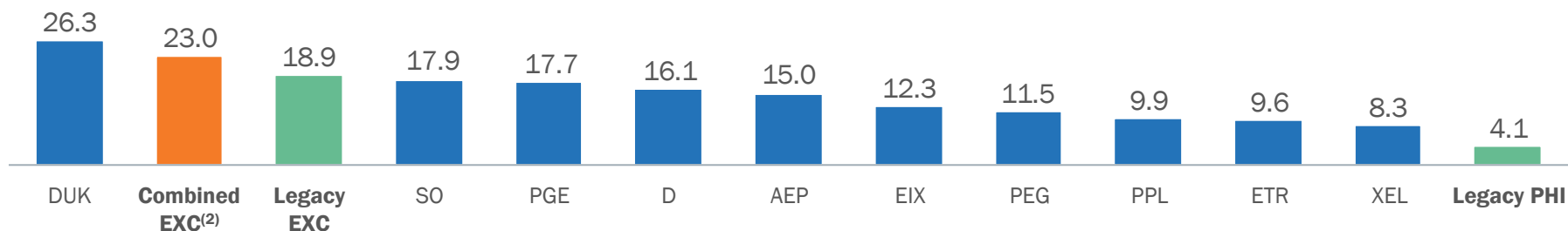
In 2015, Exelon gave approx. \$37 million to charitable and community causes.

# Exelon Utilities are an Industry Leader

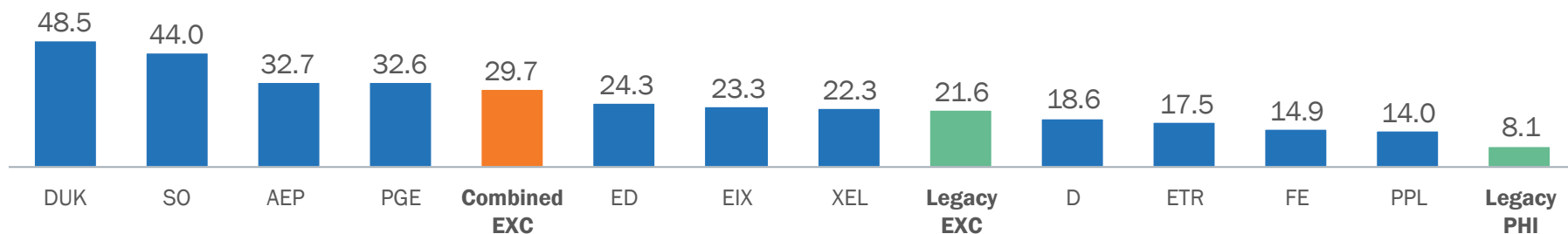
## US Utility Customers (millions)



## Total Capital Expenditures 2016-2018 (\$B)<sup>(1)</sup>



## Total Utility Rate Base (\$B)<sup>(1)</sup>



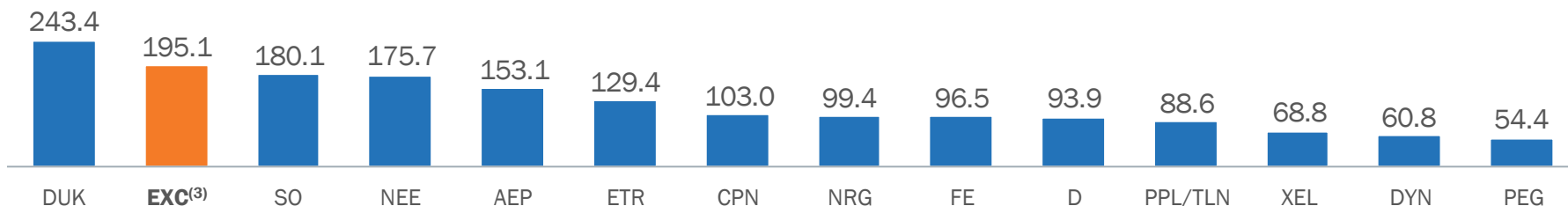
Source: Company Filings

(1) Includes utility and generation

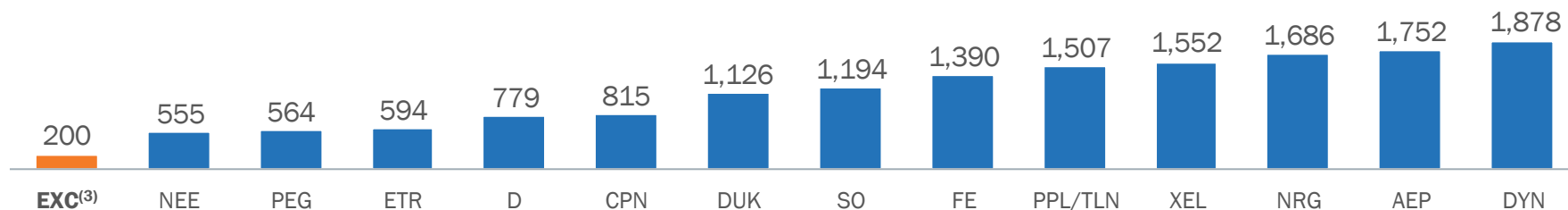
(2) \$23B includes \$15.6B of utility capital expenditures and \$7.4B of generation capital expenditures

# Exelon Generation is an Industry Leader

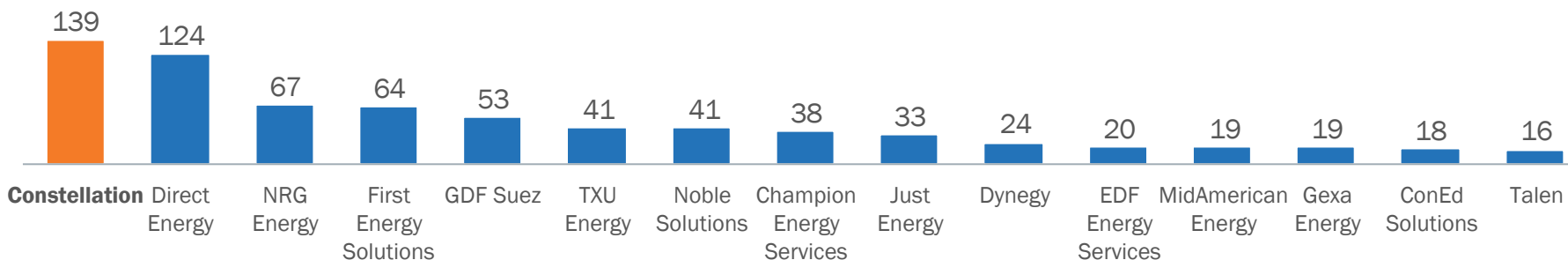
## Total Generation Output (TWh)<sup>(1)</sup>



## Carbon Intensity (lb/MWh)<sup>(1)</sup>



## Retail Load Served (TWhs)<sup>(2)</sup>



(1) Includes regulated and non-regulated generation. Source: Benchmarking Air Emissions, July 2015; <http://mjbradley.com/sites/default/files/Benchmarking-Air-Emissions-2015.pdf>

(2) Source: DNV GL Retail Landscape April 2016

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

# Best in Class Operations

## Legacy Exelon Utilities Operational Metrics

Operations	Metric	2015 YE		
		BGE	PECO	ComEd
Electric Operations	OSHA Recordable Rate			
	2.5 Beta SAIFI (Outage Frequency)			
	2.5 Beta CAIDI (Outage Duration)			
Customer Operations	Customer Satisfaction			
	Service Level % of Calls Answered in <30 sec			
	Abandon Rate			
Gas Operations	Percent of Calls Responded to in <1 Hour			No Gas Operations

Overall Rank	Electric Utility Panel of 24 Utilities	3 <sup>rd</sup>	2 <sup>nd</sup>	3 <sup>rd</sup>
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Exelon Utilities has identified and transferred best practices at each of its utilities to improve operating performance in areas such as:

- System Performance
- Emergency Preparedness
- Corrective and Preventive Maintenance

Q1	Q2
Q3	Q4

## ExGen Operational Metrics

- Continued best in class performance across our Nuclear fleet:
  - Q1 Nuclear Capacity Factor: 95.8%
  - Q1 average refueling outage duration of 24 days versus industry average refueling outage duration of 36 days
- Strong performance across our Fossil and Renewable fleet:
  - Q1 Renewables energy capture: 96.2%
  - Q1 Power dispatch match: 93.5%
  - No employee OSHA or DART recordable events in Q1

# Early Retirement of Clinton and Quad Cities

***We will shut down Clinton Power Station on June 1, 2017 and Quad Cities Generating Station on June 1, 2018 if Illinois does not pass adequate legislation by May 31, 2016 and if Quad Cities does not clear the 19/20 PJM capacity auction in May***

## Impact on Illinois of Plant Closures<sup>(1)</sup>

- The gross impact of shutting down Clinton and Quad Cities would be:
  - \$1.2 billion annually in lost economic activity in Illinois
  - 4,200 jobs lost, many of which are highly skilled, good paying jobs
- According to independent analyses by PJM and MISO, there would be a significant increase in electricity prices for Illinois residents and businesses
- Economic damages associated with an incremental increase in the release of carbon dioxide emissions would cost Illinois consumers nearly \$10 billion over 10 years

## Nuclear Plant Economics Deteriorating

- Illinois legislation aimed at leveling the playing field for zero carbon resources has failed to advance in the past two legislative sessions
- PJM power prices hit 15 year record low in March
- Illinois forward energy prices have declined by roughly 10% in the last year
- From 2009 to 2015, Quad Cities and Clinton have sustained more than \$800 million in cash flow losses on a pre-tax basis<sup>(2)</sup>

(1) Source: January 5, 2015 Response to the IL General Assembly Concerning House Resolution 1146 prepared by Illinois Commerce Commission, Illinois Power Agency, Illinois Environmental Protection Agency, and Illinois Department of Commerce and Economic Opportunity

(2) Revenues include realized energy and capacity revenue excluding any hedges; costs include all site expenses (including taxes other than income taxes), DOE spent fuel fees prior to their suspension in mid-2014, charged and allocated overhead, fuel capex, and non-fuel capex. Losses only reflect the extent to which revenues fell short of cash costs and do not reflect the absence of expected investor return on investment

# Q1 2016 Financial Results

- Delivered adjusted (non-GAAP) operating earnings in Q1 of \$0.68/share near the top of our guidance range of \$0.60-\$0.70/share

- Utilities

↑ Lower bad debt expense

↓ Unfavorable weather

↓ Higher storm costs

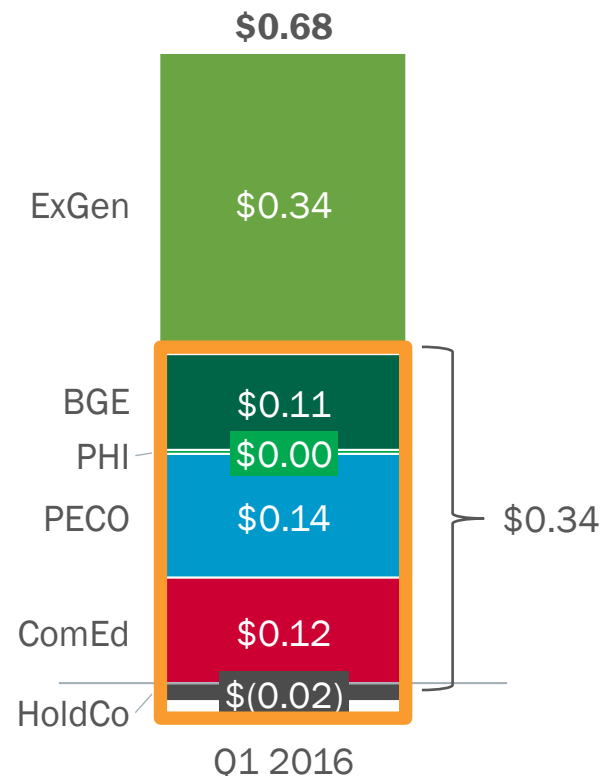
- ExGen

↑ Lower cost to serve load

↑ Strong performance at Constellation

↑ Lower O&M primarily timing within the year

## Adjusted Operating EPS Results <sup>(1,2)</sup>



**Expect Q2 2016 Adjusted Operating Earnings of \$0.50 - \$0.60 per share**

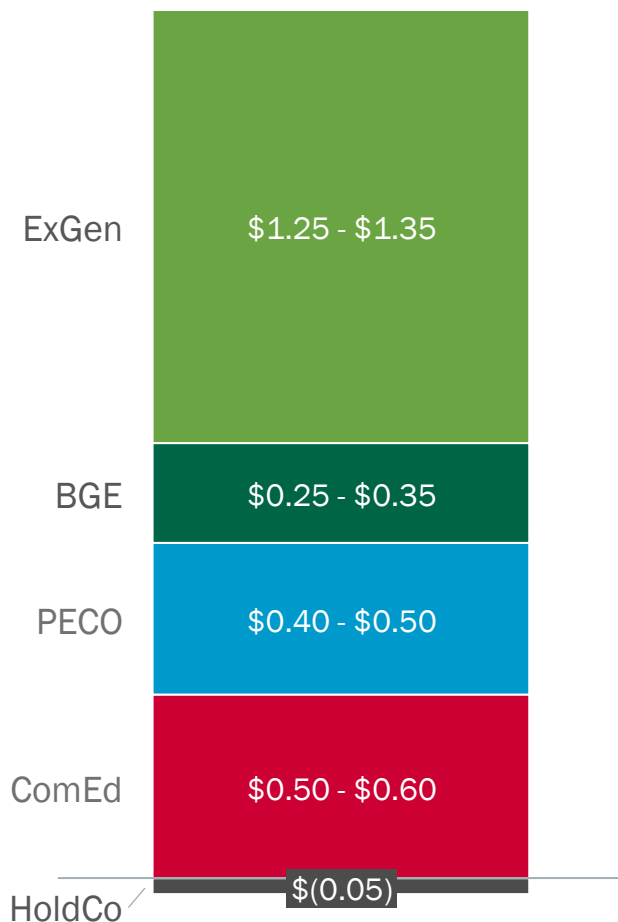
(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

(2) Amounts may not add due to rounding.



# 2016 Adjusted Operating Earnings Guidance

**\$2.40 - \$2.70<sup>(1)</sup>**

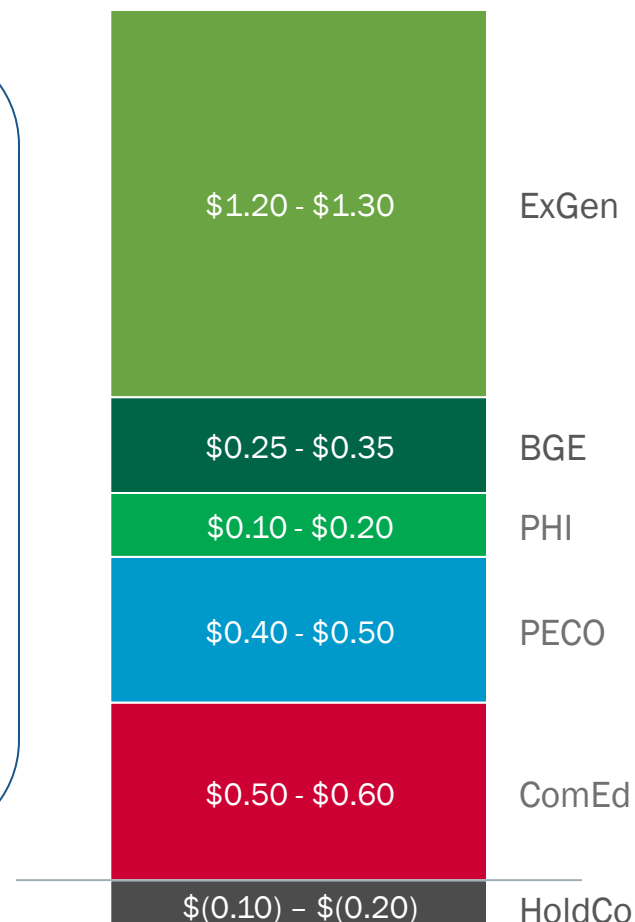


2016 Standalone Guidance

## Key Changes

- Average outstanding share count of 926M vs. 890M from Q4 standalone guidance
- Interest on debt issued for PHI transaction captured at HoldCo
- Includes PHI contribution to earnings for remainder of year

**\$2.40 - \$2.70<sup>(2,3)</sup>**



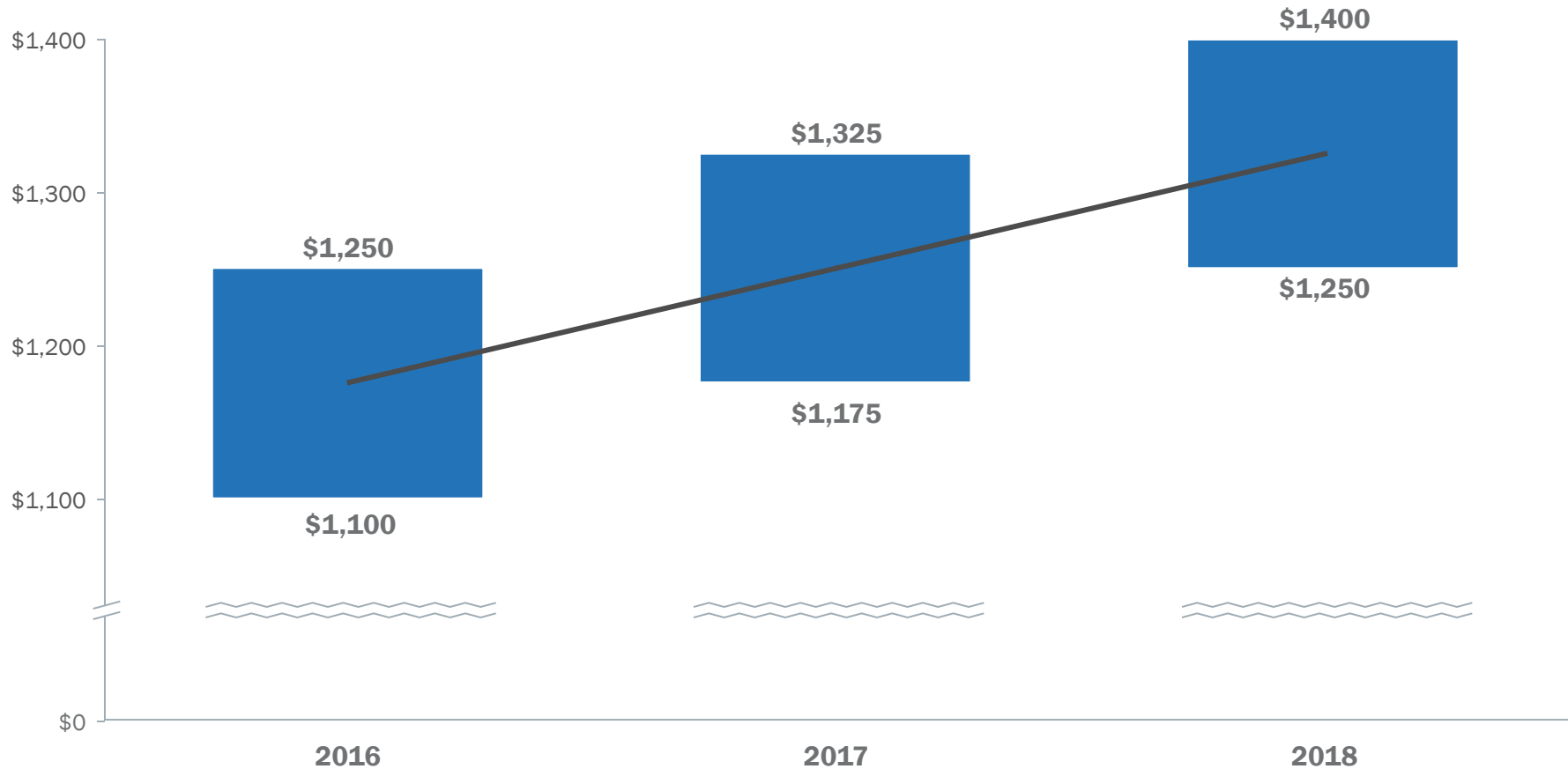
2016 Combined Guidance

**Confirming full-year guidance range of \$2.40 - \$2.70/share<sup>(2,3)</sup>**

- (1) 2016 standalone earnings guidance was based on expected average outstanding shares of 890M and assumed that equity and debt issued for Pepco Holdings acquisition was unwound in 2016. Earnings guidance for OpCos may not add up to consolidated EPS guidance. Refer to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS guidance to GAAP EPS.
- (2) 2016 combined earnings guidance is based on expected average outstanding shares of 926M. Earnings guidance for OpCos may not add up to consolidated EPS guidance.
- (3) ComEd ROE based on 30 Year average Treasury yield of 2.67% as of 3/31/16. 25 basis point move in 30 Year Treasury Rate equates to +/- \$0.01 impact to EPS.

# Reaffirming Legacy Exelon Utilities Net Income Outlook

## Exelon Utilities Net Income (\$M)<sup>(1,2)</sup>



**Legacy Exelon Utilities projected average earnings growth is still in the 7-9% range per year from 2015-2018**

(1) Numbers rounded to nearest \$25M

(2) Does not include PHI net income and represents adjusted (non-GAAP) operating earnings. Refer to slide 41 for a list of adjustments from GAAP EPS to adjusted (non-GAAP) operating earnings.

# Exelon Utilities Distribution Rate Case Schedule

	Q4 2015	Q1 2016	Q2 2016	Q3 2016	Q4 2016	Q1 2017
<b>BGE Electric and Gas Distribution Rates</b>	MD Rate Case Filed November 6		Final Order Expected June			
<b>ComEd Electric Distribution Formula Rate</b>			IL Formula Rate Case Filed April 13		Final Order Expected December	
<b>ACE Electric Distribution Rates</b>		NJ Rate Case Filed March 22				Final Order Expected Q1/Q2
<b>Pepco Electric Distribution Rates - MD</b>			MD Rate Case Filed April 19		Final Order Expected December	
<b>Pepco Electric Distribution Rates - DC</b>			DC Rate Case Filing Planned Q2/Q3			
<b>Delmarva Electric and Gas Distribution Rates - DE</b>			DE Rate Case Filing Planned			Final Order Expected
<b>Delmarva Electric Distribution Rates - MD</b>				MD Rate Case Filing Planned		Final Order Expected

# Exelon Generation: Gross Margin Update

	March 31, 2016			Change from Dec. 31, 2015		
Gross Margin Category (\$M) <sup>(1)</sup>	2016	2017	2018	2016	2017	2018
Open Gross Margin <sup>(3)</sup> (including South, West, Canada hedged gross margin)	\$4,450	\$5,350	\$5,800	\$(750)	\$(450)	\$(350)
Mark-to-Market of Hedges <sup>(3,4)</sup>	\$2,650	\$1,150	\$400	\$950	\$350	\$150
Power New Business / To Go	\$250	\$750	\$1,000	\$(200)	\$(50)	-
Non-Power Margins Executed	\$350	\$150	\$100	\$100	-	-
Non-Power New Business / To Go	\$100	\$300	\$400	\$(100)	-	-
<b>Total Gross Margin <sup>(2)</sup></b>	<b>\$7,800</b>	<b>\$7,700</b>	<b>\$7,700</b>	<b>-</b>	<b>\$(150)</b>	<b>\$(200)</b>

## Recent Developments

- Executed \$200M of Power New Business and \$100M of Non-Power New Business in Q1
- Behind ratable hedging position reflects the fundamental upside we see in power prices
  - Generation ~28-31% open in 2017
  - Power position ~5-8% behind ratable, considering cross-commodity hedges

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

2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses. Excludes Pepco Energy Services. See Slide 26 for a Non-GAAP to GAAP reconciliation of Total Gross Margin.

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

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

# Financial Developments Since Q4 2015

## Incremental Combined Company Tax Impacts<sup>(1)</sup>

	2017	2018	2019
<b>EPS</b>	\$(0.00) - \$(0.02)	\$(0.06) - \$(0.08)	\$(0.00) - \$(0.01)
<b>Cash Flow</b>	\$50M-\$100M	\$200M-\$300M	\$400M-\$500M
<b>Consolidated Tax Rate</b>	33%	34%	32%
<b>Cash Tax Rate</b>	5%	5%	10%

- ExGen earnings are lower as increased cash tax benefits reduce the Domestic Production Activities Deduction (DPAD) in 2018 but should normalize in 2019
- PHI increases cash flow by \$700M-\$850M for 2017-19 due to bonus depreciation and legacy NOLs
- Consolidated tax rate increases by as much as 200 bps through 2018 due to lower DPAD, but is expected to normalize to ~32% in 2019

## ComEd ROE Sensitivity to Interest Rates<sup>(2)</sup>

	2017	2018	2019
<b>ComEd EPS - 30 Year Treasury Rate</b>			
+25 basis points	\$0.01	\$0.01	\$0.01
-25 basis points	\$(0.01)	\$(0.01)	\$(0.01)

- ComEd allowed ROEs are calculated at the 30-Year Treasury + 580 bps with every 25 bps move in the 30-Year impacting EPS by +/- \$0.01

(1) Tax impacts are incremental to the standalone bonus depreciation impacts disclosed on the Q4 2015 earnings call for earnings in 2016: \$(0.09), 2017: \$(0.11), and 2018: \$(0.06); and for cash in 2016: \$625M, 2017: \$675M, and 2018: \$600M

(2) ComEd ROE based on 30 Year average Treasury yield of 2.67% as of 3/31/16

# Delivering Value to Shareholders Through a Defined Capital Allocation Policy

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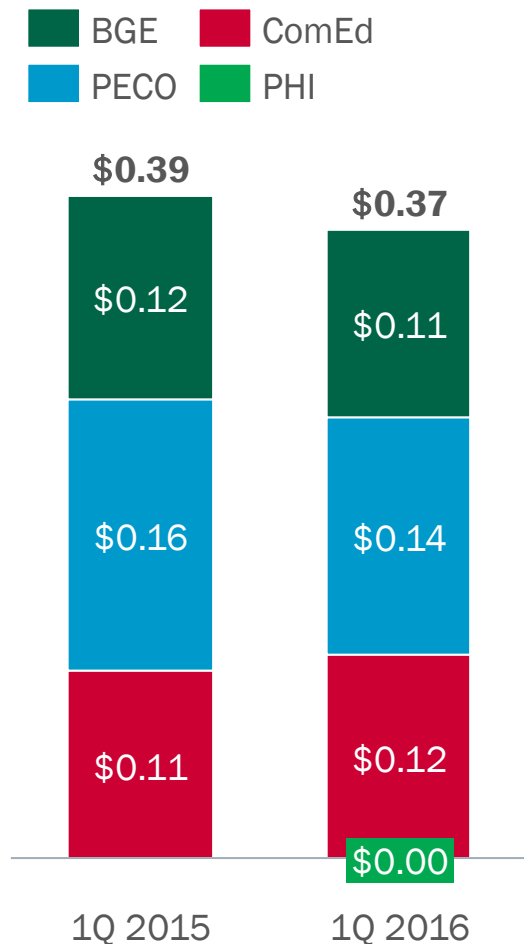
- Our **strong balance sheet** underpins our capital allocation policy
- Capital decisions are made to **maximize value to our customers and shareholders**
- We are **harvesting free cash flow** from Exelon Generation to:
  - First, **invest in utilities** where we can earn an appropriate return,
  - **Invest in contracted assets** where we can meet return thresholds, and/or
  - **Return capital** to shareholders by retiring debt, repurchasing our shares, or increasing our dividend
- We are **committed to maintaining an attractive dividend<sup>(1)</sup>**, increasing the dividend by 2.5% annually through 2018

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

# Quarter over Quarter Disclosures

# Exelon Utilities Adjusted Operating EPS Contribution<sup>(1)</sup>

## Key Drivers – 1Q16<sup>(2)</sup> vs. 1Q15:



### BGE (-0.01):

- Increased storm costs: (\$0.01)

### PECO (-0.02):

- Unfavorable weather (RNF): \$(0.04)
- Increased electric distribution rates: \$0.02

### ComEd (+0.01):

- Unfavorable weather<sup>(3)</sup>: \$(0.01)
- Increased distribution and transmission earnings due to increased capital investment<sup>(3)</sup>: \$0.02

### PHI (+0.00):

- PHI actual results from the period of March 24, 2016 to March 31, 2016 were not a significant driver: \$(0.00)

Numbers may not add due to rounding.

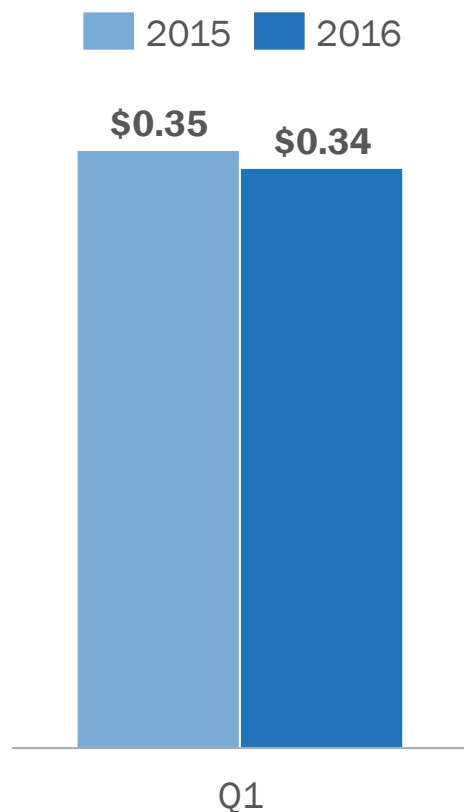
(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS.

(2) There is a \$(0.02) share differential impact spread across the utilities in Q1 2016.

(3) Due to the distribution formula rate, changes in ComEd's earnings are driven primarily by changes in 30-year U.S. Treasury rates (inclusive of ROE), rate base and capital structure in addition to weather, load and changes in customer mix.



# ExGen Adjusted Operating EPS Contribution<sup>(1)</sup>



## Key Drivers – Q1 2016 vs. Q1 2015

### ExGen (-0.01)

- Unfavorable RNF primarily due to lower realized energy prices in the Midwest, New York, and New England regions, partially offset by nuclear refueling outage timing, fewer non-refueling outage days, and increased capacity pricing: \$(0.02)
- Higher depreciation costs primarily due to increased nuclear decommissioning amortization and ongoing capital expenditures: \$(0.02)
- Other: \$0.03

(excludes Salem)	<u>Q1 2015 Actual</u>	<u>Q1 2016 Actual</u>
<b>Planned Refueling Outage Days</b>	89	70
<b>Non-refueling Outage Days</b>	32	10
<b>Nuclear Capacity Factor</b>	92.7%	95.8%

Numbers may not add due to rounding

(1) Refer to the Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

# **Exelon Generation Disclosures**

**March 31, 2016**

# Portfolio Management Strategy

## Strategic Policy Alignment

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

## Three-Year Ratable Hedging

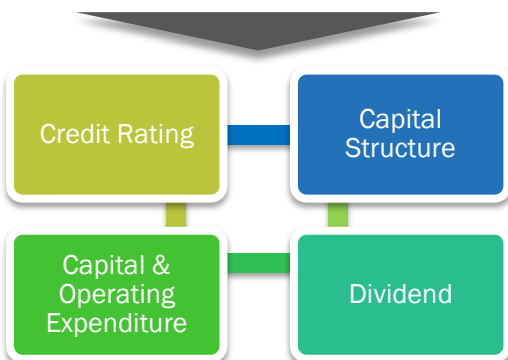
- Ensure stability in near-term cash flows and earnings
- Disciplined approach to hedging
- Tenor aligns with customer preferences and market liquidity
- Multiple channels to market that allow us to maximize margins
- Large open position in outer years to benefit from price upside

## Bull / Bear Program

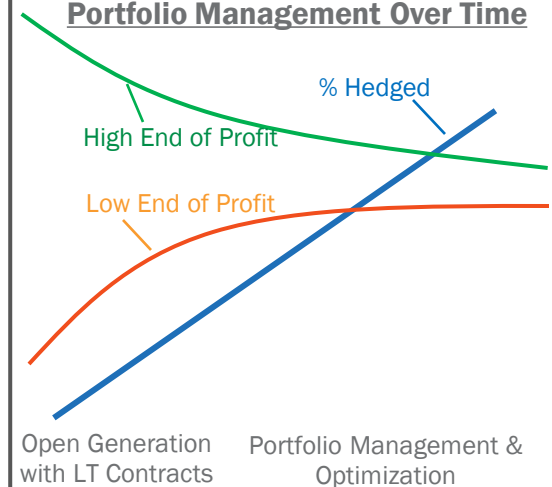
- Ability to exercise fundamental market views to create value within the ratable framework
- Modified timing of hedges versus purely ratable
- Cross-commodity hedging (heat rate positions, options, etc.)
- Delivery locations, regional and zonal spread relationships

## Align Hedging & Financials

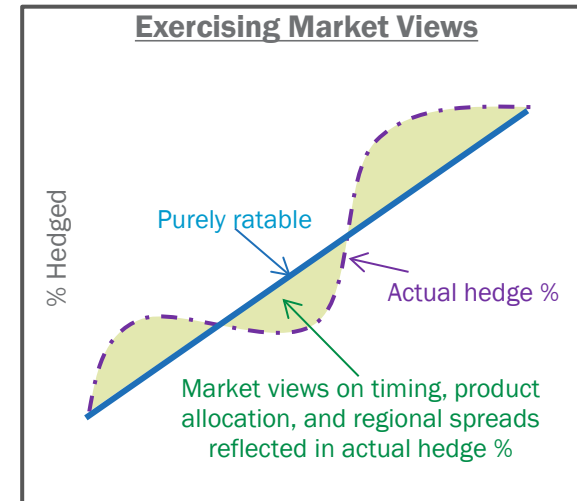
### Establishing Minimum Hedge Targets



## Portfolio Management Over Time



## Exercising Market Views

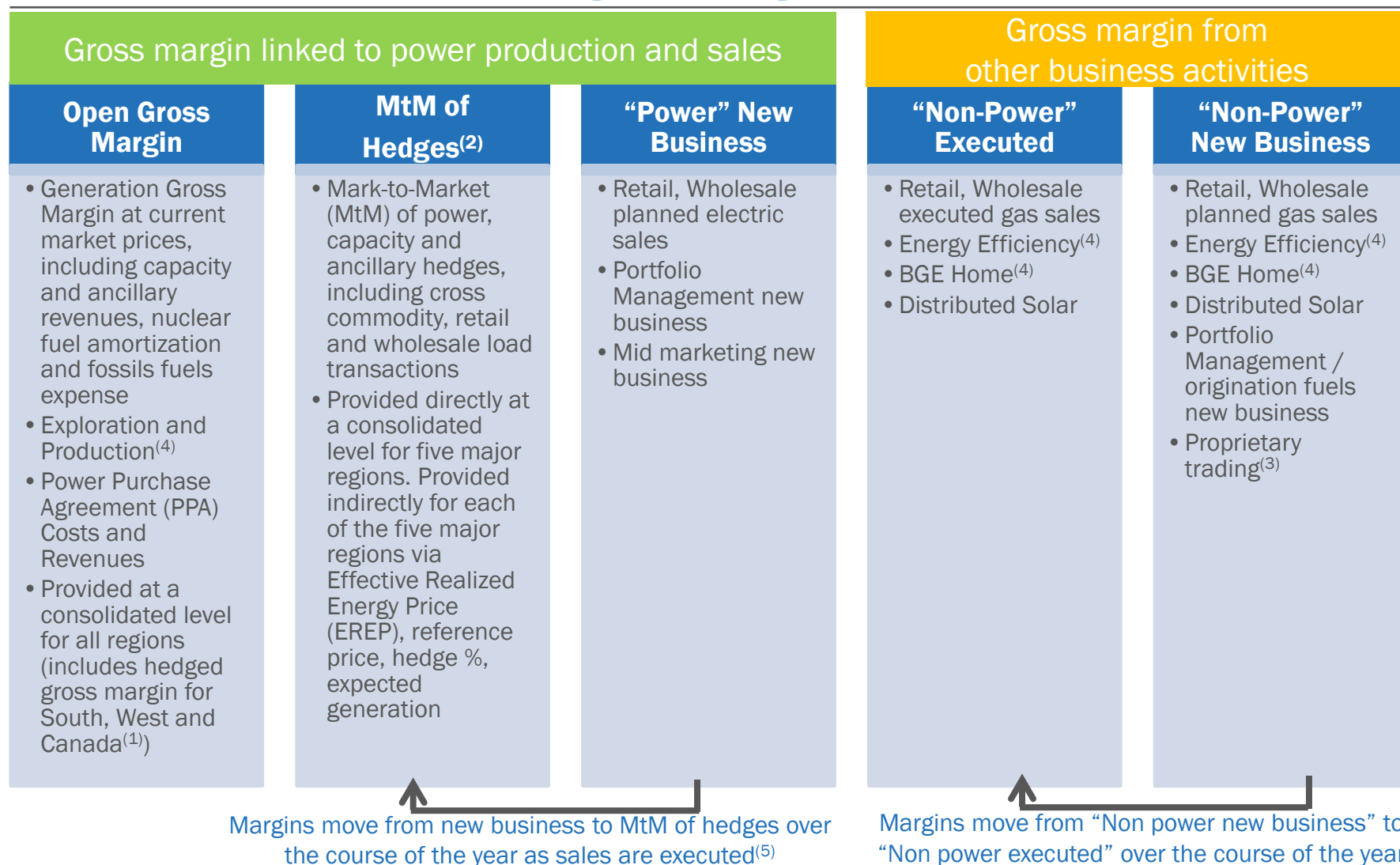


**Protect Balance Sheet**

**Ensure Earnings Stability**

**Create Value**

# Components of Gross Margin Categories



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

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

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

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

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

# ExGen Disclosures

Gross Margin Category (\$M) <sup>(1)</sup>	2016	2017	2018
Open Gross Margin (including South, West & Canada hedged GM) <sup>(3)</sup>	\$4,450	\$5,350	\$5,800
Mark-to-Market of Hedges <sup>(3,4)</sup>	\$2,650	\$1,150	\$400
Power New Business / To Go	\$250	\$750	\$1,000
Non-Power Margins Executed	\$350	\$150	\$100
Non-Power New Business / To Go	\$100	\$300	\$400
<b>Total Gross Margin<sup>(2)</sup></b>	<b>\$7,800</b>	<b>\$7,700</b>	<b>\$7,700</b>

Reference Prices <sup>(5)</sup>	2016	2017	2018
Henry Hub Natural Gas (\$/MMbtu)	\$2.19	\$2.77	\$2.87
Midwest: NiHub ATC prices (\$/MWh)	\$24.00	\$27.10	\$27.26
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$29.31	\$33.59	\$32.52
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	\$4.57	\$4.28	\$4.39
New York: NY Zone A (\$/MWh)	\$26.25	\$33.23	\$32.66
New England: Mass Hub ATC Spark Spread(\$/MWh) <i>ALQN Gas, 7.5HR, \$0.50 VOM</i>	\$6.65	\$8.65	\$9.28

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

(2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses. Excludes Pepco Energy Services. See Slide 26 for a Non-GAAP to GAAP reconciliation of Total Gross Margin.

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

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

(5) Based on March 31, 2016 market conditions

# ExGen Disclosures

Generation and Hedges	2016	2017	2018
<u>Exp. Gen (GWh)<sup>(1)</sup></u>	<b>200,100</b>	<b>205,400</b>	<b>206,600</b>
Midwest	97,700	96,300	96,700
Mid-Atlantic <sup>(2)</sup>	63,300	61,300	60,600
ERCOT	17,200	26,000	30,800
New York <sup>(2)</sup>	9,300	9,200	9,100
New England	12,600	12,600	9,400
<u>% of Expected Generation Hedged<sup>(3)</sup></u>	<b>96%-99%</b>	<b>69%-72%</b>	<b>37%-40%</b>
Midwest	92%-95%	65%-68%	31%-34%
Mid-Atlantic <sup>(2)</sup>	105%-108%	77%-80%	45%-48%
ERCOT	95%-98%	73%-76%	39%-42%
New York <sup>(2)</sup>	91%-94%	64%-67%	52%-55%
New England	79%-82%	53%-56%	24%-27%
<u>Effective Realized Energy Price (\$/MWh)<sup>(4)</sup></u>			
Midwest	\$34.00	\$33.00	\$31.50
Mid-Atlantic <sup>(2)</sup>	\$45.50	\$45.00	\$41.00
ERCOT <sup>(5)</sup>	\$11.50	\$7.50	\$4.00
New York <sup>(2)</sup>	\$61.00	\$50.50	\$42.50
New England <sup>(5)</sup>	\$27.50	\$18.00	\$9.50

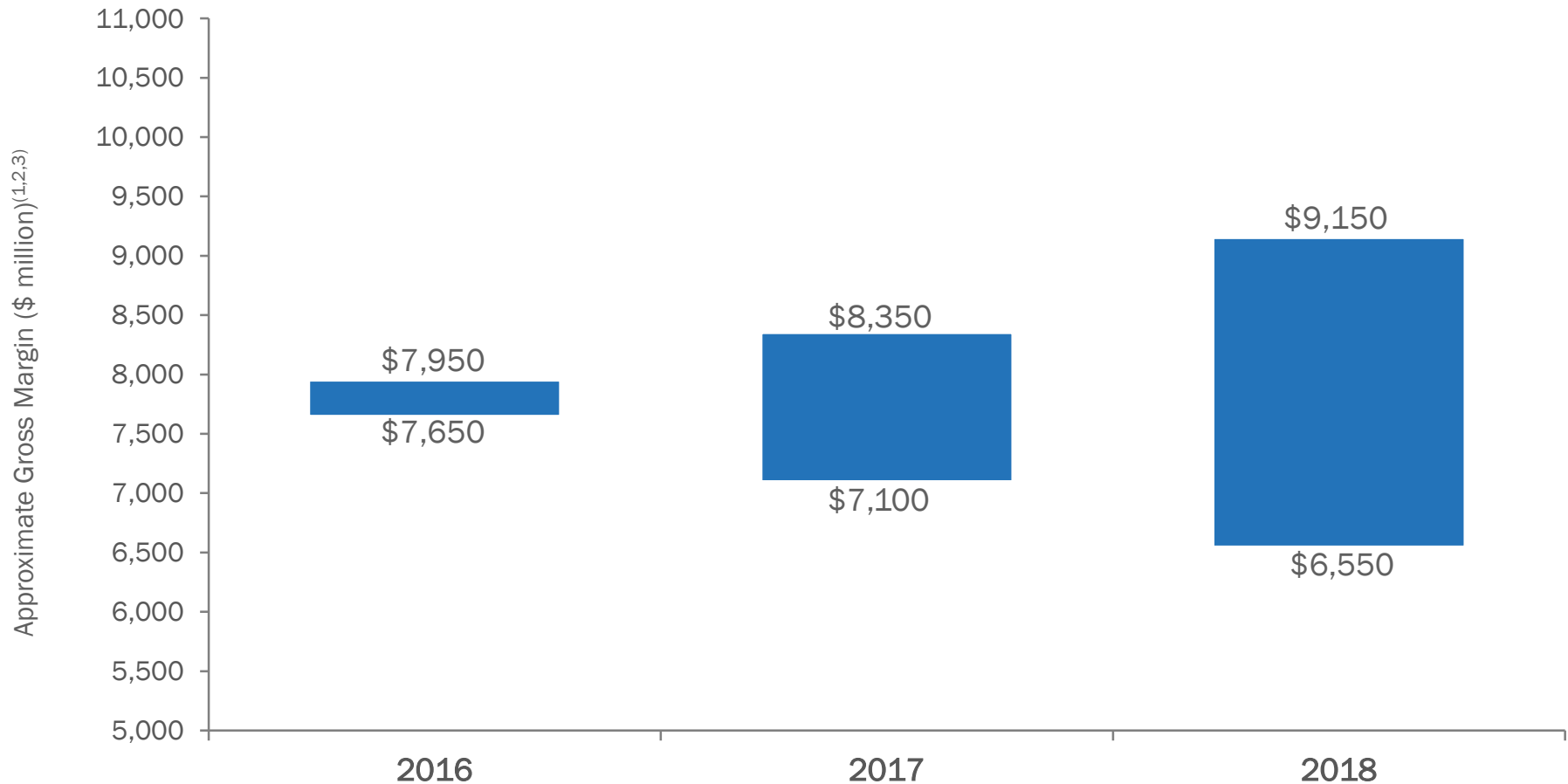
(1) Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 12 refueling outages in 2016, 15 in 2017, and 14 in 2018 at Exelon-operated nuclear plants, and Salem. Expected generation assumes capacity factors of 94.1%, 93.4% and 93.7% in 2016, 2017 and 2018 respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2017 and 2018 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 and RPM capacity revenue, but includes the mark-to-market value of capacity contracted at prices other than RPM clearing prices including our load obligations. It can be compared with the reference prices used to calculate open gross margin in order to determine the mark-to-market value of Exelon Generation's energy hedges. (5) Spark spreads shown for ERCOT and New England.

# ExGen Hedged Gross Margin Sensitivities

Gross Margin Sensitivities (With Existing Hedges) <sup>(1)</sup>	2016	2017	2018
Henry Hub Natural Gas (\$/Mmbtu)			
+ \$1/Mmbtu	\$20	\$270	\$570
- \$1/Mmbtu	\$60	\$(300)	\$(580)
NiHub ATC Energy Price			
+ \$5/MWh	\$35	\$185	\$350
- \$5/MWh	\$(30)	\$(180)	\$(345)
PJM-W ATC Energy Price			
+ \$5/MWh	\$(15)	\$65	\$160
- \$5/MWh	\$20	\$(80)	\$(165)
NYPP Zone A ATC Energy Price			
+ \$5/MWh	-	\$15	\$20
- \$5/MWh	-	\$(15)	\$(20)
Nuclear Capacity Factor			
+/- 1%	+/- \$25	+/- \$35	+/- \$35

(1) Based on March 31, 2016 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 prices sensitivities are derived by adjusting the power price assumption while keeping all other prices inputs constant; Due to correlation of the various assumptions, the hedged gross margin impact calculated by aggregating individual sensitivities may not be equal to the hedged gross margin impact calculated when correlations between the various assumptions are also considered; Sensitivities based on commodity exposure which includes open generation and all committed transactions; Excludes EDF's equity share of CENG Joint Venture

# ExGen Hedged Gross Margin Upside/Risk



- (1) Represents an approximate range of expected gross margin, taking into account hedges in place, between the 5th and 95th percent confidence levels assuming all unhedged supply is sold into the spot market; Approximate gross margin ranges are based upon an internal simulation model and are subject to change based upon market inputs, future transactions and potential modeling changes; These ranges of approximate gross margin in 2017 and 2018 do not represent earnings guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years; The price distributions that generate this range are calibrated to market quotes for power, fuel, load following products, and options as of March 31, 2016
- (2) Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions
- (3) Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses. Excludes Pepco Energy Services. See Slide 26 for a Non-GAAP to GAAP reconciliation of Total Gross Margin. Excludes EDF's equity ownership share of the CENG Joint Venture.



# Illustrative Example of Modeling Exelon Generation 2017 Gross Margin

ZECJ-FIN-21

PUBLIC

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	<div>← \$5.35 billion →</div>					
(B)	Expected Generation (TWh)	96.3	61.3	26.0	9.2	12.6	
(C)	Hedge % (assuming mid-point of range)	66.5%	78.5%	74.5%	65.5%	54.5%	
(D=B*C)	Hedged Volume (TWh)	64.0	48.1	19.4	6.0	6.9	
(E)	Effective Realized Energy Price (\$/MWh)	\$33.00	\$45.00	\$7.50	\$50.50	\$18.00	
(F)	Reference Price (\$/MWh)	\$27.10	\$33.59	\$4.28	\$33.23	\$8.65	
(G=E-F)	Difference (\$/MWh)	\$5.90	\$11.41	\$3.22	\$17.27	\$9.35	
(H=D*G)	Mark-to-market value of hedges (\$ million) <sup>(1)</sup>	\$380	\$550	\$60	\$105	\$65	
(I=A+H)	Hedged Gross Margin (\$ million)	\$6,500					
(J)	Power New Business / To Go (\$ million)	\$750					
(K)	Non-Power Margins Executed (\$ million)	\$150					
(L)	Non-Power New Business / To Go (\$ million)	\$300					
(N=I+J+K+L)	Total Gross Margin <sup>(2)</sup>	\$7,700 million					

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

(2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses. Excludes Pepco Energy Services. See Slide 26 for a Non-GAAP to GAAP reconciliation of Total Gross Margin.

# Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in \$M) <sup>(1)</sup>	2016	2017	2018
Revenue Net of Purchased Power and Fuel Expense <sup>(2)(3)</sup>	\$8,425	\$8,325	\$8,325
Other Revenues <sup>(4)</sup>	\$(325)	\$(325)	\$(325)
Direct cost of sales incurred to generate revenues for certain Constellation businesses <sup>(5)</sup>	\$(300)	\$(300)	\$(300)
<b>Total Gross Margin (Non-GAAP, as shown on slide 11)</b>	<b>\$7,800</b>	<b>\$7,700</b>	<b>\$7,700</b>

Key ExGen Modeling Inputs (in \$M) <sup>(1)(6)</sup>	2016
Other Revenues (excluding Gross Receipts Tax) <sup>(4)</sup>	\$200
O&M <sup>(7)</sup>	\$(4,475)
Taxes Other Than Income (TOTI) <sup>(8)</sup>	\$(350)
Depreciation & Amortization <sup>(9)</sup>	\$(1,075)
Interest Expense	\$(375)
<b>Effective Tax Rate</b>	<b>34.0%</b>

(1) All amounts rounded to the nearest \$25M. Excludes Pepco Energy Services.

(2) Revenue net of purchased power and fuel expense (RNF), a non-GAAP measure, is calculated as the GAAP measure of operating revenue less the GAAP measure of purchased power and fuel expense. ExGen does not forecast the GAAP components of RNF separately. RNF also includes the RNF of our proportionate ownership share of CENG.

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

(4) Other revenues reflects revenues from operating services agreement with Fort Calhoun, variable interest entities, funds collected through revenues for decommissioning the former PECO nuclear plants through regulated rates and gross receipts tax revenues.

(5) Reflects the cost of sales and depreciation expense of certain Constellation businesses of Generation. Excludes Pepco Energy Services.

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

(7) ExGen adjusted O&M excludes direct cost of sales for certain Constellation business, P&L neutral decommissioning costs and the impact from O&M related to variable interest entities. Refer to the Appendix for a reconciliation of adjusted (non-GAAP) O&M to GAAP O&M

(8) TOTI excludes gross receipts tax of \$125M

(9) Depreciation & Amortization excludes the cost of sales impact of ExGen's non-power businesses of \$25M

# Illinois Nuclear Plant Details

Clinton	
<b>Capacity</b>	1,069 MW
<b>Generation Output<sup>(2)</sup></b>	8,700 GWh
<b>Start of Operations</b>	1987
<b>License Expiration</b>	2026
<b>Refueling Cycle</b>	12 month
<b>Committed to Run Through</b>	May 31, 2017
<b>Employees</b>	~700

Quad Cities <sup>(1)</sup>	
<b>Capacity</b>	1,403 MW
<b>Generation Output<sup>(2)</sup></b>	11,700 GWh
<b>Start of Operations</b>	1973
<b>License Expiration</b>	2032
<b>Refueling Cycle (per unit)</b>	24 month
<b>Committed to Run Through</b>	May 31, 2018
<b>Employees</b>	~800

(1) Capacity and generation output reflect proportionate ownership share

(2) 2015 actuals

# **Additional Disclosures**

# Exelon Utilities Overview

## Operating Statistics

### Commonwealth Edison

Customers:	3,800,000
Service Territory:	11,400 sq. miles
Peak Load:	23,753 MW
2015 Rate Base:	\$10.6 bn

### PECO Energy

Customers:	2,100,000
Service Territory:	2,100 sq. miles
Peak Load:	8,983 MW
2015 Rate Base:	\$6.0 bn

### Baltimore Gas and Electric

Customers:	1,900,000
Service Territory:	2,300 sq. miles
Peak Load:	7,236 MW
2015 Rate Base:	\$5.0 bn

### Potomac Electric Power

Customers:	842,000
Service Territory:	640 sq. miles
Peak Load:	7,023 MW
2015 Rate Base:	\$3.9 bn

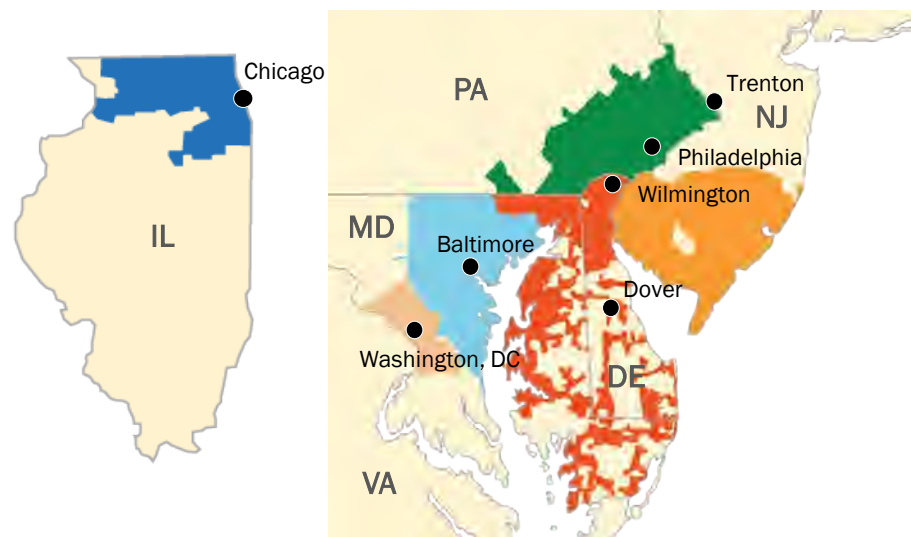
### Atlantic City Electric

Customers:	547,000
Service Territory:	2,700 sq. miles
Peak Load:	3,009 MW
2015 Rate Base:	\$1.8 bn

### Delmarva Power & Light

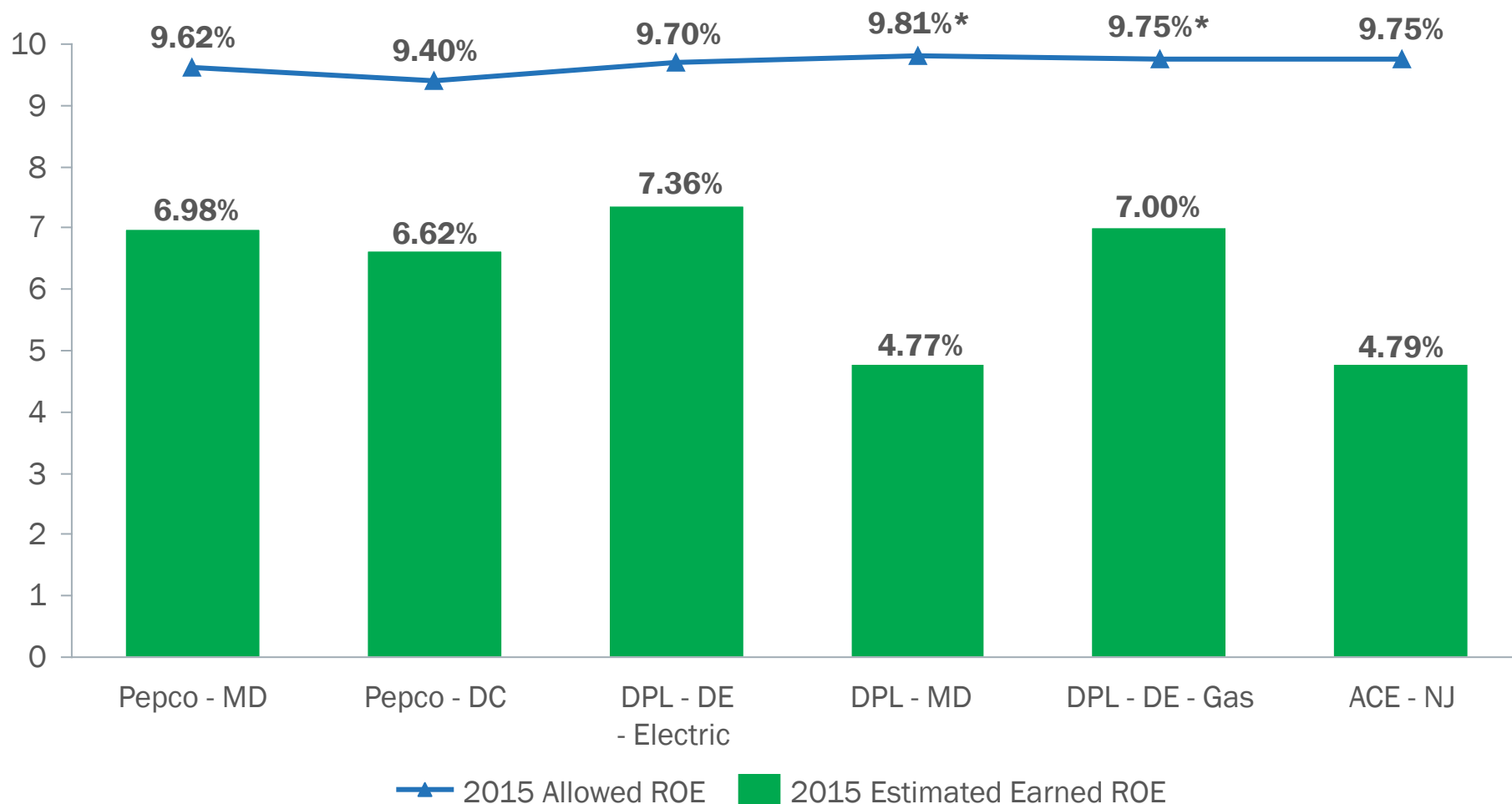
Customers:	645,000
Service Territory:	5,000 sq. miles
Peak Load:	4,288 MW
2015 Rate Base:	\$2.4 bn

## Combined Service Territory



- Atlantic City Electric Service Territory
- Baltimore Gas and Electric Service Territory
- ComEd Service Territory
- Delmarva Power & Light Service Territory
- PECO Energy Service Territory
- Potomac Electric Power Service Territory

# 2015 Earned vs. Allowed ROE at PHI Utilities



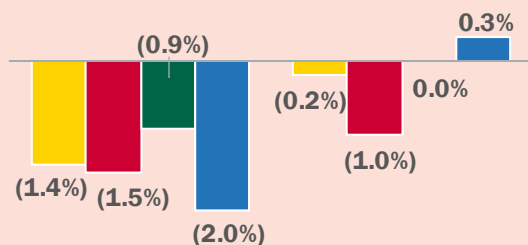
**Significant Opportunity for Earned ROE Improvement at PHI Utilities**

\* ROE for purposes of calculating AFUDC and regulatory asset carrying costs.

# Exelon Utilities Load

■ All Customers 
 ■ Residential 
 ■ Small C&I 
 ■ Large C&I

## ComEd



2015

2016E

Chicago GMP

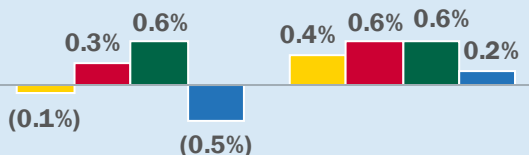
1.5%

Chicago Unemployment

6.3%

2016 load is driven by impacts of energy efficiency partially offset by slowly improving economy

## PECO



2015

2016E

Philadelphia GMP

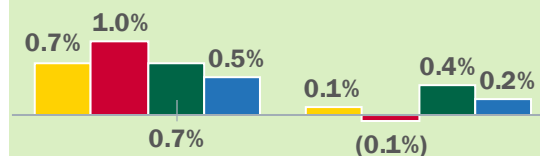
2.1%

Philadelphia Unemployment

4.5%

2016 load growth is driven by slowly improving economic conditions coupled with solid residential customer growth, partially offset by energy efficiency

## BGE



2015

2016E

Baltimore GMP

1.1%

Baltimore Unemployment

5.0%

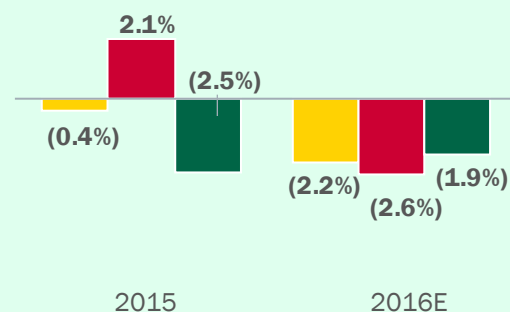
2016 load growth is driven by the impacts of energy efficiency and a weaker economic outlook, partially offset by moderate customer growth

Notes: Data is weather normalized and not adjusted for leap year. Source of economic outlook data is IHS (March 2016). Assumes 2016 GDP of 2.3% and U.S. unemployment of 5.0%. ComEd has the ROE collar as part of the distribution formula rate and BGE is decoupled which mitigates the load risk. QTD and YTD actual data can be found in earnings release tables. BGE amounts have been adjusted for prior quarter true-ups.

# Exelon Utilities Load (cont'd)

■ All Customers ■ Residential ■ C&I

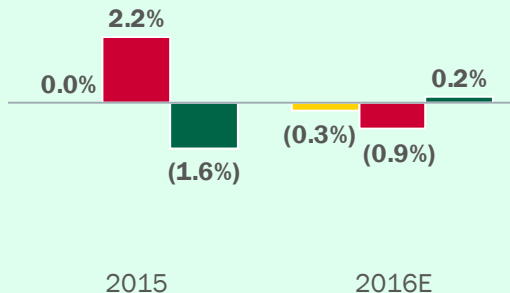
## ACE



**ACE GMP** 0.3%  
**ACE Unemployment** 7.3%

2016 load is driven by the impacts of energy efficiency and distributed energy partially offset by improving residential and commercial customer growth.

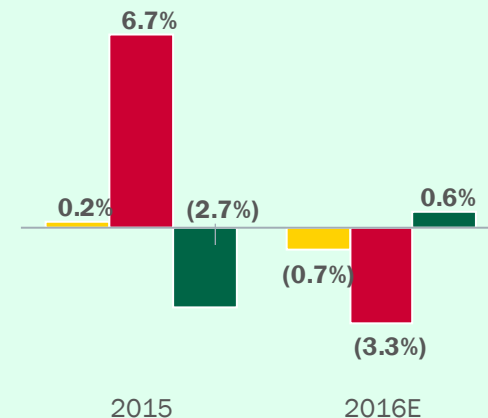
## Delmarva



**DPL GMP** 2.2%  
**DPL Unemployment** 4.8%

2016 load is driven by the impacts of energy efficiency and distributed energy partially offset by improved employment and residential, commercial & industrial customer growth.

## Pepco



**Pepco GMP** 2.2%  
**Pepco Unemployment** 5.3%

2016 load is driven by the impacts of energy efficiency and distributed energy partially offset by improved commercial usage and residential customer growth.

Notes: Data is weather normalized using 20-year historical average and not adjusted for leap year. Starting with 2Q16, PHI will be moving to 30-year historical average for weather normalization. Source of economic outlook data is IHS (March 2016). Assumes 2016 GDP of 2.3% and U.S. unemployment rate of 5.0%. Pepco and DPL MD are decoupled which mitigates the load risk. QTD and YTD actual data can be found in earnings release tables. ACE includes Atlantic City, Vineland and Ocean City MSAs (Metropolitan Statistical Area). DPL MSA includes Wilmington Division, Dover MSA and Salisbury MSA. Pepco MSA includes the city of Washington DC and Silver Spring/Frederick Division.



# PHI Jurisdiction Comparison

Rate Cases	District of Columbia	Maryland	Delaware	New Jersey
<b>Partially Forecasted Test Year</b>	Yes <sup>(1)</sup>	Yes	Yes	Yes
<b>Required to update test year to actual</b>	No	Yes	No	Yes
<b>Timing for Rate Implementation</b>	No statute; target to complete cases within 9 months of filing	Statute - 7 months; rates automatically go into effect subject to refund	Statute - 7 months; company files request to implement rates, subject to refund	Statute - 9 months; company files request to implement rates, subject to refund <sup>(2)</sup>
<b>Time Restrictions on Initiating Subsequent Rate Filings</b>	No	No	No	No
<b>Staff Party to Case</b>	No	Yes	Yes	Yes
<b>Commissions</b>				
<b>Full Time/Part Time</b>	Full-Time	Full-Time	Part-Time	Full-Time
<b>Appointed/Elected</b>	Appointed	Appointed	Appointed	Appointed
<b>Length of Term</b>	4 years	5 years	5 years	6 years
<b>Commissioners<sup>(3)</sup></b>				
<b>Name (Term Expiration)</b>	<b>Betty Ann Kane (2018)</b> Joanne Doddy Fort (2016) Willie L. Phillips (2018)	<b>Kevin Hughes (2018)</b> Harold Williams (2017) Anne Hoskins (2016) Jeannette M. Mills (2019) Michael T. Richard (2020)	<b>Dallas Winslow (2020)</b> Joann Conaway (2020) Harold Gray (2020) Kim Drexler (2020) Manubhai Karia (2020)	<b>Richard S. Mroz (2021)</b> Diane Solomon (2018) Joseph L. Fiordaliso (2019) Mary-Anna Holden (2017) Upendra J. Chivukula (2019)

(1) The District of Columbia PSC allows rates to be developed using a partially forecasted test period. The Company is required to update the test period to actual within 180 days of the completion of the rate proceeding

(2) The statutory deadline for NJBPU decisions has not been successfully enforced by a utility; fully litigated cases can take 12 months or more for decision

(3) Chairperson denoted in bold

# BGE Electric and Gas Distribution Rate Case

	Electric	Gas
<b>Docket #</b>	<b>9406</b>	
<b>Test Year</b>	<b>December 2014- November 2015</b>	
<b>Common Equity Ratio <sup>(1)</sup></b>	<b>53.7%</b>	
<b>Requested ROE</b>	<b>10.60%</b>	<b>10.50%</b>
<b>Requested Rate of Return</b>	<b>7.95%</b>	<b>7.90%</b>
<b>Rate Base (adjusted)</b>	<b>\$3.0B</b>	<b>\$1.2B</b>
<b>Revenue Requirement Increase <sup>(1)</sup></b>	<b>\$117.6M</b>	<b>\$79.1M</b>
<b>Proposed Distribution Increase as % of overall bill</b>	<b>~3%</b>	<b>~9%</b>
<b>Notes</b>	<ul style="list-style-type: none"> <li>• 11/06/15 BGE filed application with the MDPSC seeking increases in electric &amp; gas distribution base rates; request was subsequently revised in Q1 to reflect impact of additional actual data</li> <li>• \$141M or ~72% of the total \$197M distribution rate increase is for recovery of Smart Grid investment</li> <li>• Requested incremental conduit fees of \$31M be recovered through a rider</li> <li>• 210 Day Proceeding</li> <li>• June 2016 - PSC order expected</li> <li>• New rates are in effect shortly after the final order</li> </ul>	

(1) Based on the 12 months ended 11/30/2015.

# ComEd April 2016 Distribution Formula Rate

The 2016 distribution formula rate filing established the net revenue requirement used to set the rates that will take effect in January 2017 after the Illinois Commerce Commission's (ICC's) review. There are two components to the annual distribution formula rate filing:

- **Filing Year:** Based on 2015 costs and 2016 projected plant additions.
- **Annual Reconciliation:** For 2015, this amount reconciles the revenue requirement reflected in rates in effect during 2015 to the actual costs for that year. The annual reconciliation impacts cash flow in 2017 but the earnings impact has been recorded in 2015 as a regulatory asset.

<b>Docket #</b>	<b>16-0259</b>
<b>Filing Year</b>	<b>2015 Calendar Year Actual Costs and 2016 Projected Net Plant Additions</b> are used to set the rates for calendar year 2017. Rates currently in effect (docket 15-0287) for calendar year 2016 were based on 2014 actual costs and 2015 projected net plant additions
<b>Reconciliation Year</b>	<b>Reconciles Revenue Requirement reflected in rates during 2015 to 2015 Actual Costs Incurred.</b> Revenue requirement for 2015 is based on docket 14-0312 (2013 actual costs and 2014 projected net plant additions) approved in December 2014.
<b>Common Equity Ratio</b>	~ <b>46%</b> for both the filing and reconciliation year
<b>ROE</b>	<b>8.64%</b> for the filing year (2015 30-yr Treasury Yield of 2.84% + 580 basis point risk premium) and <b>8.59%</b> for the reconciliation year (2015 30-yr Treasury Yield of 2.79% + 580 basis point risk premium – 5 basis points performance metrics penalty). For 2016 and 2017, the actual allowed ROE reflected in net income will ultimately be based on the average of the 30-year Treasury Yield during the respective years plus 580 basis point spread, absent any metric penalties
<b>Requested Rate of Return</b>	~ <b>7%</b> for both the filing and reconciliation years
<b>Rate Base</b>	<b>\$8,830 million</b> – Filing year (represents projected year-end rate base using 2015 actual plus 2016 projected capital additions). 2016 and 2017 earnings will reflect 2016 and 2017 year-end rate base respectively. \$7,780 million - Reconciliation year (represents year-end rate base for 2015)
<b>Revenue Requirement Increase</b>	<b>\$138M increase</b> (\$1M decrease due to the 2015 reconciliation and collar adjustment offset by a \$139M increase related to the filing year). The 2015 reconciliation impact on net income was recorded in 2015 as a regulatory asset.
<b>Timeline</b>	<ul style="list-style-type: none"> <li>• 04/13/16 Filing Date</li> <li>• 240 Day Proceeding</li> </ul>

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

# ACE Electric Distribution Rate Case

<b>Docket #</b>	ER16030252
<b>Test Year</b>	2015 Calendar Year
<b>Test Period</b>	Partially Forecasted Test Period (9 months actual & 3 months forecasted)
<b>Requested Common Equity Ratio</b>	49.5%
<b>Requested Rate of Return</b>	ROE: 10.60%; ROR: 8.06%
<b>Proposed Rate Base</b>	\$1.4B
<b>Requested Revenue Requirement Increase</b>	\$84.4M
<b>Residential Total Bill % Increase</b>	6.3%
<b>Notes</b>	<ul style="list-style-type: none"> <li>• 3/22/16 ACE filed application with the NJBPU seeking increase in electric distribution base rates</li> <li>• 12 month forward looking reliability and other plant additions from January 2016 through December 2016 (\$15.2M of revenue) included in revenue requirement request</li> <li>• PowerAhead Program to fund accelerated investments in grid resiliency, incremental to the five year capital plan (not included in revenue requirement request): Capital \$176 million (Distribution Line Hardening \$108 million; Storm Response \$35 million; and Other Programs \$33 million)</li> <li>• 9 month statutory deadline for NJBPU decisions has not been successfully enforced by a utility; fully litigated cases can take 12 months or more for decision</li> <li>• NJBPU order expected first half of 2017</li> </ul>

# Pepco MD Electric Distribution Rate Case

<b>Docket #</b>	9418
<b>Test Year</b>	2015 Calendar Year
<b>Test Period</b>	Partially Forecasted Test Period (9 months actual & 3 months forecasted)
<b>Requested Common Equity Ratio</b>	49.6%
<b>Requested Rate of Return</b>	ROE: 10.60%; ROR: 8.01%
<b>Proposed Rate Base</b>	\$1.8B
<b>Requested Revenue Requirement Increase</b>	\$126.8M
<b>Residential Total Bill % Increase</b>	10.4%
<b>Notes</b>	<ul style="list-style-type: none"> <li>• 4/19/16 Pepco MD filed application with the MDPSC seeking increase in electric distribution base rates</li> <li>• Size of ask is driven by 2 years of capital investment, recovery of AMI investments and new depreciation rates.</li> <li>• 12 month forward looking reliability and other plant additions from January 2016 through December 2016 (\$20.7M of revenue); included in revenue requirement request</li> <li>• Extension of the Grid Resiliency Program to fund accelerated investments in grid resiliency, incremental to the capital plan (not included in revenue requirement request) <ul style="list-style-type: none"> <li>• Capital \$31.6 million (Feeder Work \$24.0 million and Reclosing Devices \$7.6 million) in 2017-2018</li> </ul> </li> <li>• 7 Month Proceeding</li> <li>• Q42016 - PSC order expected</li> <li>• New rates are in effect shortly after the final order</li> </ul>

# **Appendix**

## **Reconciliation of Non-GAAP Measures**

# 1Q 2015 YTD GAAP EPS Reconciliation

<b>Three Months Ended March 31, 2015</b>	<b><u>ExGen</u></b>	<b><u>ComEd</u></b>	<b><u>PECO</u></b>	<b><u>BGE</u></b>	<b><u>Other</u></b>	<b><u>Exelon</u></b>
<b>2015 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$0.35</b>	<b>\$0.11</b>	<b>\$0.16</b>	<b>\$0.12</b>	<b>\$(0.03)</b>	<b>\$0.71</b>
Mark-to-market impact of economic hedging activities	(0.11)	-	-	-	-	(0.11)
Unrealized gains related to NDT fund investments	0.03	-	-	-	-	0.03
Merger and integration costs	(0.01)	-	-	-	(0.01)	(0.02)
Mark-to-market impact of PHI merger related interest swaps	-	-	-	-	(0.06)	(0.06)
Amortization of commodity contract intangibles	0.03	-	-	-	-	0.03
Midwest Generation bankruptcy recoveries	0.01	-	-	-	-	0.01
CENG non-controlling interest	(0.01)	-	-	-	-	(0.01)
<b>1Q 2015 GAAP Earnings Per Share</b>	<b>\$0.51</b>	<b>\$0.11</b>	<b>\$0.16</b>	<b>\$0.12</b>	<b>\$(0.10)</b>	<b>\$0.80</b>

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

# 1Q 2016 YTD GAAP EPS Reconciliation (continued)

<u>Three Months Ended March 31, 2016</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>PHI</u>	<u>Other</u>	<u>Exelon</u>
<b>2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$0.34</b>	<b>\$0.12</b>	<b>\$0.14</b>	<b>\$0.11</b>	<b>\$0.00</b>	<b>\$(0.02)</b>	<b>\$0.68</b>
Mark-to-market impact of economic hedging activities	0.07	-	-	-	-	-	0.07
Unrealized gains related to NDT fund investments	0.03	-	-	-	-	-	0.03
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	(0.01)	0.01	-	-	(0.04)	(0.05)	(0.08)
Merger commitments	-	-	-	-	(0.30)	(0.12)	(0.42)
Long-lived asset impairment	(0.08)	-	-	-	-	-	(0.08)
Reassessment of state deferred income taxes	(0.01)	-	-	-	-	0.01	-
Cost management program	(0.01)	-	-	-	-	-	(0.02)
CENG non-controlling interest	(0.01)	-	-	-	-	-	(0.01)
<b>1Q 2016 GAAP Earnings (Loss) Per Share</b>	<b>\$0.33</b>	<b>\$0.13</b>	<b>\$0.14</b>	<b>\$0.11</b>	<b>\$(0.34)</b>	<b>\$(0.18)</b>	<b>\$0.18</b>

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



# GAAP to Operating Adjustments

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- **Exelon's Q1 2016 adjusted (non-GAAP) operating earnings excludes the earnings effects of the following:**
  - Mark-to-market adjustments from economic hedging activities
  - Unrealized gains and losses from NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements
  - Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at the date of acquisition of Integrys in 2014
  - Certain costs incurred associated with PHI acquisition
  - Merger commitments related to settlement of PHI acquisition
  - Impairment of certain upstream assets
  - Non-cash impact of the remeasurement of state deferred income taxes, primarily as a result of PHI acquisition
  - Costs incurred related to cost management initiatives
  - Generation's non-controlling interest related to CENG exclusion items
  - Other unusual items