

Earnings Conference Call 2nd Quarter 2015

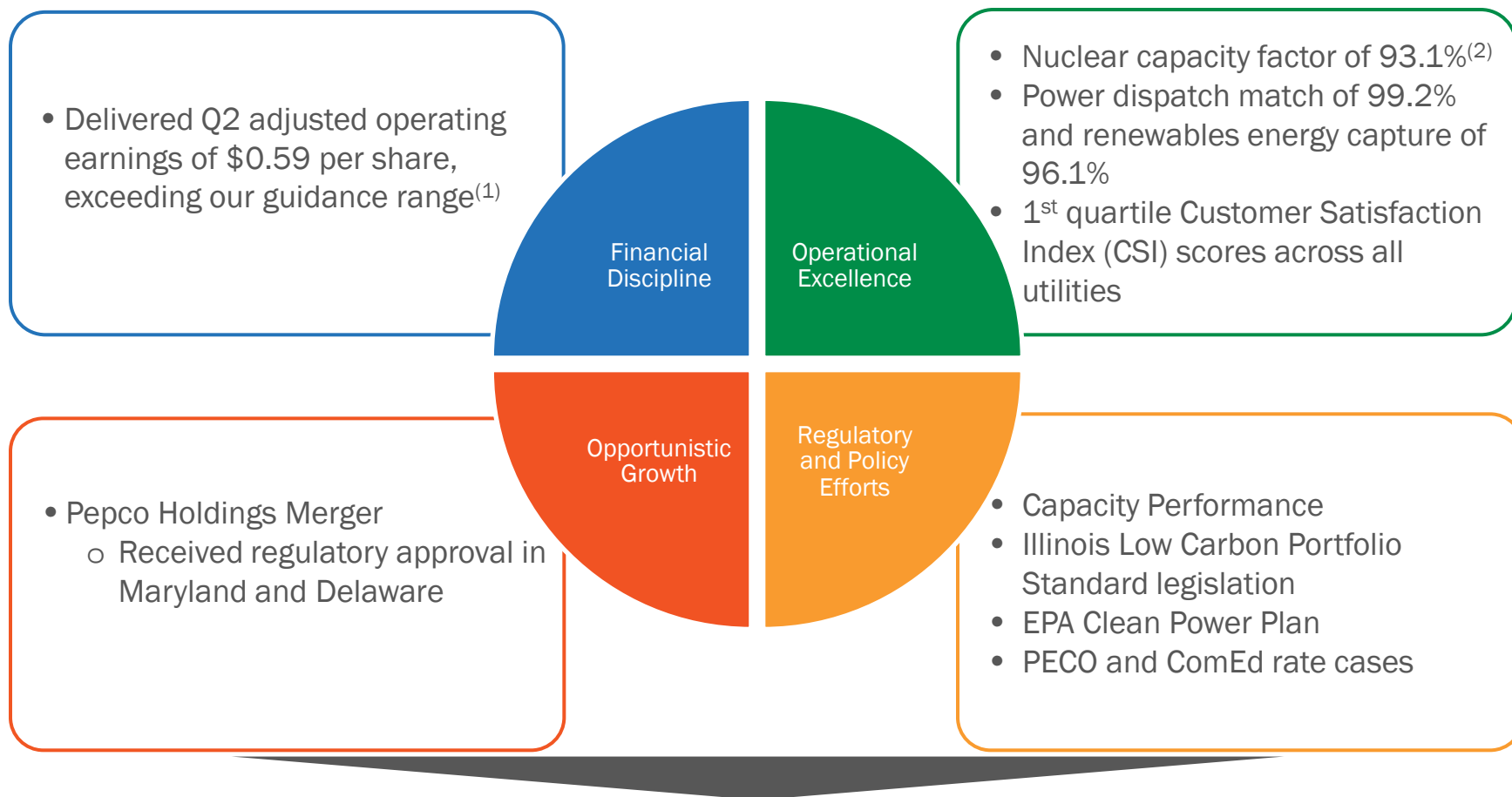
July 29, 2015



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, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company and Exelon Generation Company, LLC (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2014 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 22; (2) Exelon's Second Quarter 2015 Quarterly Report on Form 10-Q (to be filed on July 29, 2015) in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 19; 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.

Q2 2015 in Review



Delivered another strong quarter of financial results and operational performance across the company

- (1) Represents adjusted (non-GAAP) operating EPS. 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) Exelon operated plants at ownership, excluding Salem

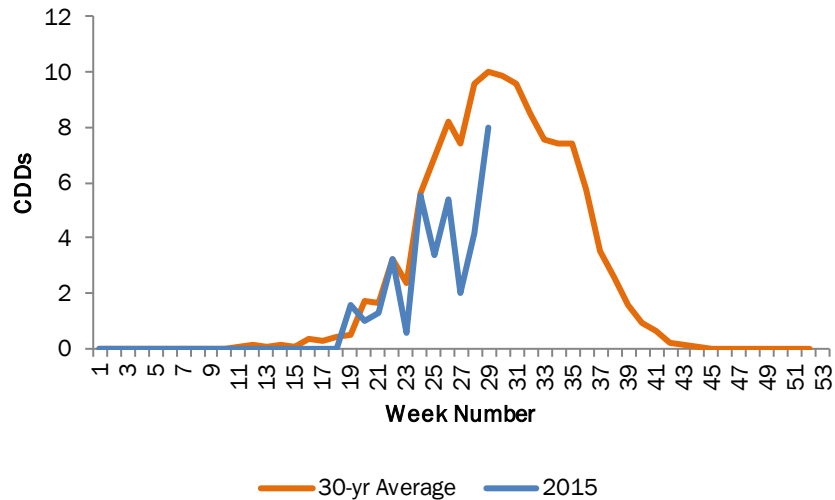
Forward Market Outlook

Q2 2015 Lower Volatility and Lower Prices

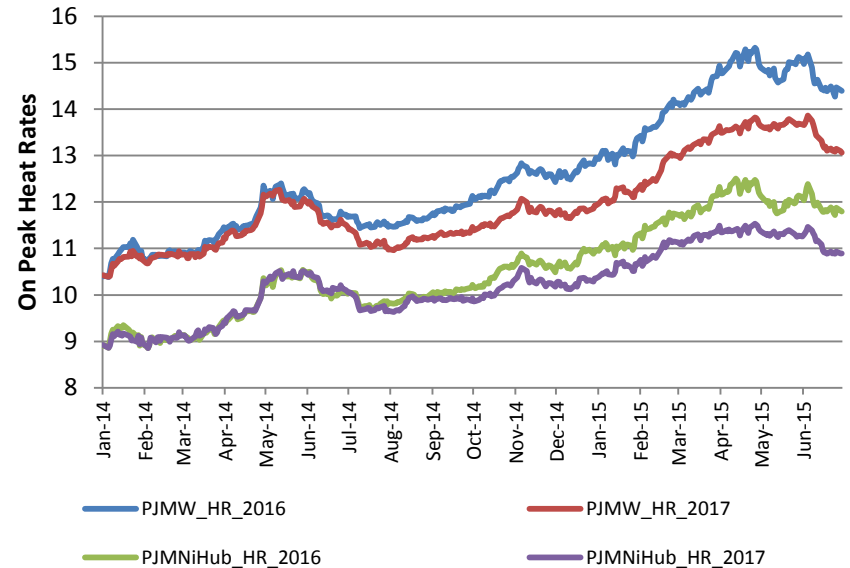
Spot Market Update

- The spot power market in 2015 has been less volatile compared to 2014
- Spot market conditions are driving weaker prices:
 - Cooling degree days** this summer have been below the 30-year average in Chicago and near normal on the East Coast
 - NYMEX gas prices** averaged \$2.72 in Q2 2015, while gas prices in Q2 2014 averaged \$4.64, a \$1.92 MMBtu difference year over year
 - TETCo M3 basis prices** continue to stay weak with Q2 2015 averaging a \$1.05 discount to NYMEX

Cooling Degree Days - Chicago



Forward Markets Reacted To Spot Prices



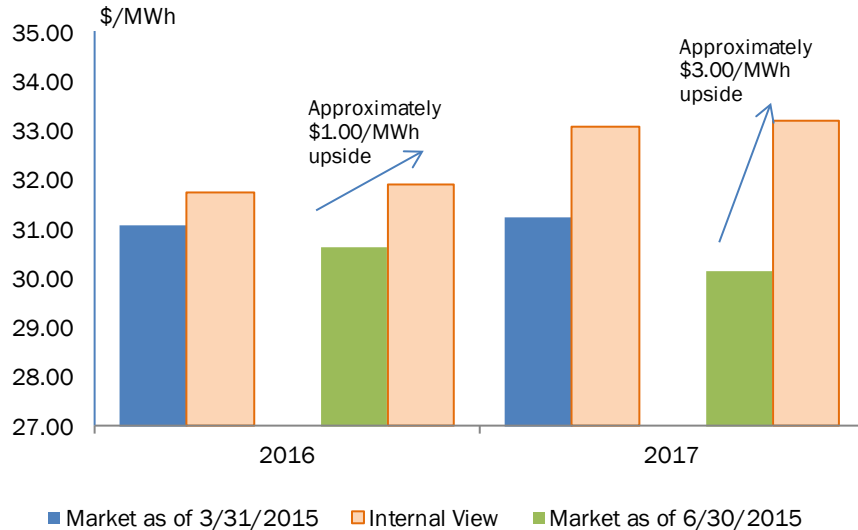
Impacts on Forward Markets

- While forward natural gas prices stayed relatively flat during the quarter, we saw a significant decrease in power prices and subsequently heat rates in 2016 and 2017
- The lack of liquidity in the forward power markets has exacerbated the drops in forward power prices and heat rates

Cool weather in the Midwest has pressured power prices across the region. Our fundamental view is that gas and power prices will be stronger in the forward years.

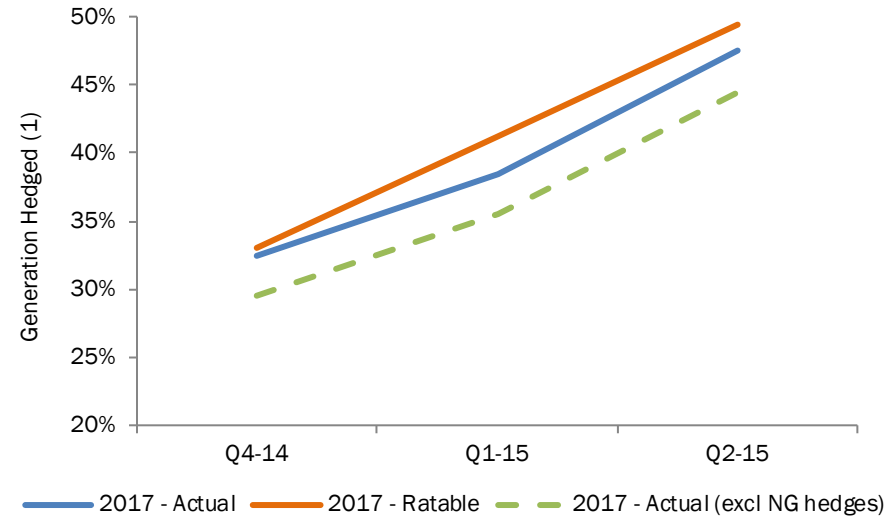
Forward Markets and Hedging Activity

NiHub Market versus Fundamental View



- Our fundamental view remains relatively unchanged
- We expect further upside in NiHub forward market based on our fundamental forecast given current natural gas prices, expected retirements, new generation resources, and load assumptions

2017: Maintaining a More Open Position⁽¹⁾



- We align our hedging strategies with our fundamental views by leaving portfolio exposure to power price upside
- We have left a significant amount of our portfolio open to moves in the power market, when considering our behind ratable and cross commodity strategies
 - Generation 54-56% open in 2017
 - 7-8% behind ratable

We are deploying a behind ratable strategy and a cross-commodity position to broaden exposure to power upside

(1) Mid-point of disclosed total portfolio hedge % range was used

Exelon Generation: Gross Margin Update

	June 30, 2015			Change from Mar 31, 2015		
Gross Margin Category (\$M) ⁽¹⁾	2015	2016	2017	2015	2016	2017
Open Gross Margin ⁽³⁾ (including South, West, Canada hedged gross margin)	\$5,250	\$5,700	\$5,750	\$(350)	\$(200)	\$(300)
Mark-to-Market of Hedges ^(3,4)	\$1,850	\$900	\$500	\$550	\$300	\$150
Power New Business / To Go	\$100	\$450	\$900	\$(150)	\$(50)	\$100
Non-Power Margins Executed	\$350	\$200	\$100	\$50	\$50	\$50
Non-Power New Business / To Go	\$100	\$250	\$350	\$(50)	\$(50)	\$(50)
Total Gross Margin ⁽²⁾	\$7,650	\$7,500	\$7,600	\$50	\$50	\$(50)

Recent Developments

- Load serving business had a strong quarter driven by our generation to load matching strategy
- Power prices declined, natural gas prices were relatively flat, and heat rates contracted during the quarter
- Behind ratable reflecting the fundamental upside we see in power prices in 2016 and 2017

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. See Slide 29 for a Non-GAAP to GAAP reconciliation of Total Gross Margin.

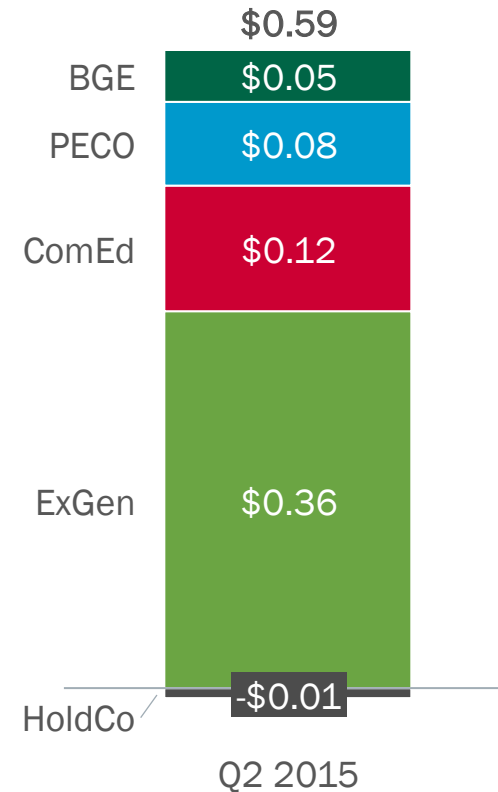
3) Excludes EDF's equity ownership share of the CENG Joint Venture

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

Key Financial Messages

- Delivered adjusted (non-GAAP) operating earnings in Q2 of \$0.59/share exceeding our guidance range of \$0.45-\$0.55/share
- Utilities
 - ↑ Increased distribution revenues
 - ↑ Lower uncollectible expense at BGE
 - ↔ Net neutral weather impacts
- ExGen
 - ↑ Lower costs to serve load
 - ↑ Strong portfolio management

Adjusted Operating EPS Results ^(1,2)



Expect Q3 2015 earnings of \$0.65 - \$0.75/share and narrowing full-year guidance range from \$2.25 - \$2.55/share to \$2.35 - \$2.55/share^(3,4)

- (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
- (3) ComEd ROE based on 30 Year average Treasury yield of 2.94% as of 6/30/15. 25 basis point move in 30 Year Treasury Rate equates to +/- \$0.01 impact to EPS.
- (4) 2015 earnings guidance based on expected average outstanding shares of ~892M. Refer to Appendix for a reconciliation of adjusted non-GAAP operating EPS guidance to GAAP EPS.

2015 Projected Sources and Uses of Cash

(\$ in millions) ⁽¹⁾	BGE	ComEd	PECO	Total Utilities	ExGen	Corp ⁽⁶⁾	Exelon 2015E	Cash Balance	
Beginning Cash Balance ⁽²⁾								3,575	(1) All amounts rounded to the nearest \$25M.
Adjusted Cash Flow from Operations ⁽³⁾	600	2,000	675	3,300	3,275	25	6,600		(2) Excludes counterparty collateral activity.
Base CapEx and Nuclear Fuel	0	0	0	0	(2,375)	(50)	(2,450)		
Free Cash Flow	600	2,000	675	3,300	900	(25)	4,175		(3) Adjusted Cash Flow from Operations (non-GAAP) primarily includes net cash flows from operating activities and net cash flows from investing activities excluding capital expenditures at ownership.
Net Financing (excluding items below)	(75)	500	350	775	200	3,400	4,375		
Project Financing	n/a	n/a	n/a	n/a	(50)	n/a	(50)		
Equity Issuance	0	0	0	0	0	1,875	1,875		
Contribution from Parent	0	100	0	100	0	(100)	0		
Other Financing ⁽⁴⁾	300	75	0	350	1,125	300	1,800		(4) Other Financing primarily includes expected changes in short-term debt and tax-exempt bond issuance at ExGen.
Financing	225	675	350	1,225	1,275	5,475	7,975		
Total Free Cash Flow and Financing Growth	825	2,675	1,025	4,525	2,175	5,425	12,150		(5) Dividends are subject to declaration by the Board of Directors.
Utility Investment	(700)	(2,400)	(600)	(3,700)	0	0	(3,700)		
ExGen Growth	0	0	0	0	(1,050)	0	(1,050)		
Dividend ⁽⁵⁾							(1,100)		(6) Includes cash flow activity from Holding Company, eliminations, and other corporate entities.
Other CapEx and Dividend	(700)	(2,400)	(600)	(3,700)	(1,050)	0	(5,850)		
Total Cash Flow	125	275	450	825	1,125	5,425	6,300		
Ending Cash Balance ⁽²⁾								9,850	

Consistent and reliable free cash flows

Operational excellence and financial discipline drives free cash flow reliability

- ✓ Generating ~\$4B of free cash flow in 2015, including \$0.9B at ExGen and \$3.3B at the Utilities

Supported by a strong balance sheet

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

- ✓ Completed financing for PHI Acquisition including:
 - \$4.2B Long-term debt issuance
 - \$1.9B Equity issuance
- ✓ HoldCo: Retired \$0.8B LTD note at maturity in June

Enable growth & value creation

Creating value for customers, communities and shareholders

- ✓ Investing \$4.7B, with \$3.7B at the Utilities and \$1B at ExGen

Exelon Generation Disclosures

June 30, 2015

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

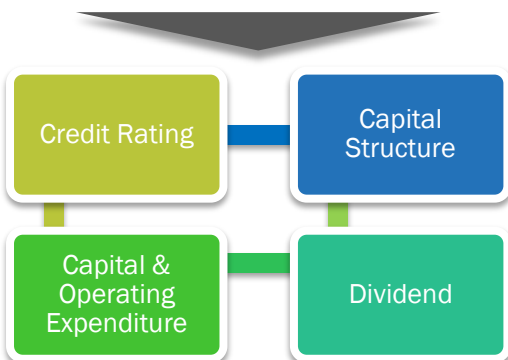
- Ensure stability in near-term cash flows and earnings
- Disciplined approach to hedging
- Tenor aligns with customer preferences and market liquidity
- Multiple channels to market that allow us to maximize margins
- Large open position in outer years to benefit from price upside

Bull / Bear Program

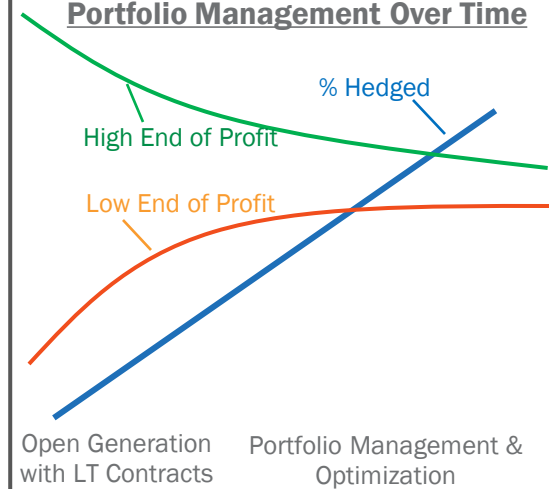
- Ability to exercise fundamental market views to create value within the ratable framework
- Modified timing of hedges versus purely ratable
- Cross-commodity hedging (heat rate positions, options, etc.)
- Delivery locations, regional and zonal spread relationships

Align Hedging & Financials

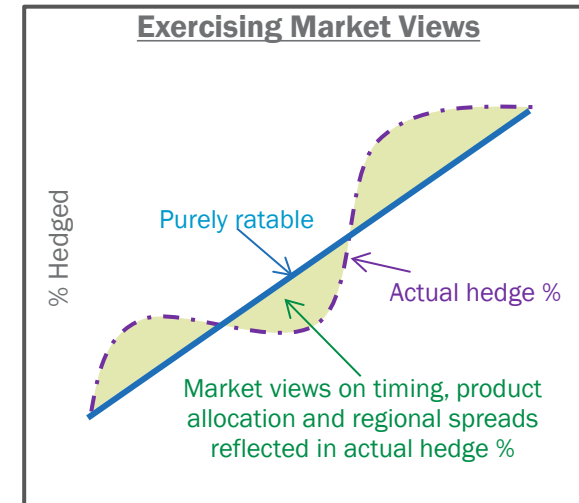
Establishing Minimum Hedge Targets



Portfolio Management Over Time



Exercising Market Views

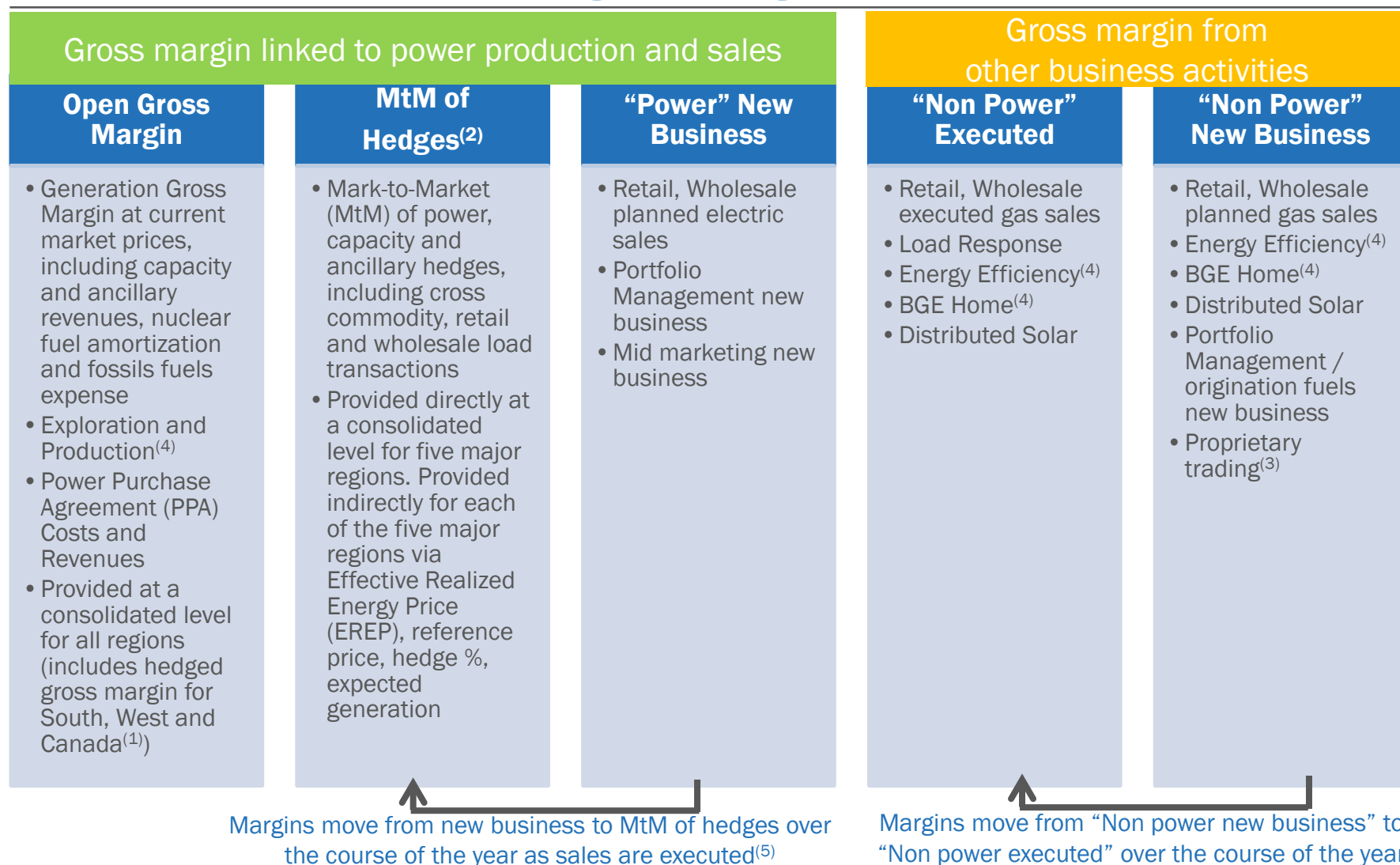


Protect Balance Sheet

Ensure Earnings Stability

Create Value

Components of Gross Margin Categories



(1) Hedged gross margins for South, West & Canada region 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) ⁽¹⁾	2015	2016	2017
Open Gross Margin (including South, West & Canada hedged GM) ⁽³⁾	\$5,250	\$5,700	\$5,750
Mark-to-Market of Hedges ^(3,4)	\$1,850	\$900	\$500
Power New Business / To Go	\$100	\$450	\$900
Non-Power Margins Executed	\$350	\$200	\$100
Non-Power New Business / To Go	\$100	\$250	\$350
Total Gross Margin⁽²⁾	\$7,650	\$7,500	\$7,600

Reference Prices ⁽⁵⁾	2015	2016	2017
Henry Hub Natural Gas (\$/MMbtu)	\$2.86	\$3.17	\$3.36
Midwest: NiHub ATC prices (\$/MWh)	\$28.75	\$30.65	\$30.17
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$37.89	\$38.27	\$36.99
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	\$3.43	\$3.82	\$4.06
New York: NY Zone A (\$/MWh)	\$33.12	\$34.03	\$33.52
New England: Mass Hub ATC Spark Spread (\$/MWh) <i>ALQN Gas, 7.5HR, \$0.50 VOM</i>	\$4.85	\$8.77	\$9.87

(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. See Slide 29 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 June 30, 2015 market conditions

ExGen Disclosures

Generation and Hedges	2015	2016	2017
<u>Exp. Gen (GWh)</u> ⁽¹⁾	190,300	198,500	204,200
Midwest	96,500	97,300	95,900
Mid-Atlantic ⁽²⁾	61,700	63,000	61,000
ERCOT	12,700	16,300	25,300
New York ⁽²⁾	9,300	9,300	9,300
New England	10,100	12,600	12,700
<u>% of Expected Generation Hedged</u> ⁽³⁾	98%-101%	77%-80%	46%-49%
Midwest	97%-100%	72%-75%	38%-41%
Mid-Atlantic ⁽²⁾	100%-103%	82%-85%	55%-58%
ERCOT	99%-102%	93%-96%	60%-63%
New York ⁽²⁾	94%-97%	76%-79%	48%-51%
New England	99%-102%	67%-70%	28%-31%
<u>Effective Realized Energy Price (\$/MWh)</u> ⁽⁴⁾			
Midwest	\$35.00	\$34.00	\$34.00
Mid-Atlantic ⁽²⁾	\$49.50	\$45.50	\$44.50
ERCOT ⁽⁵⁾	\$19.50	\$10.00	\$7.00
New York ⁽²⁾	\$46.50	\$41.50	\$39.00
New England ⁽⁵⁾	\$32.50	\$19.00	\$17.00

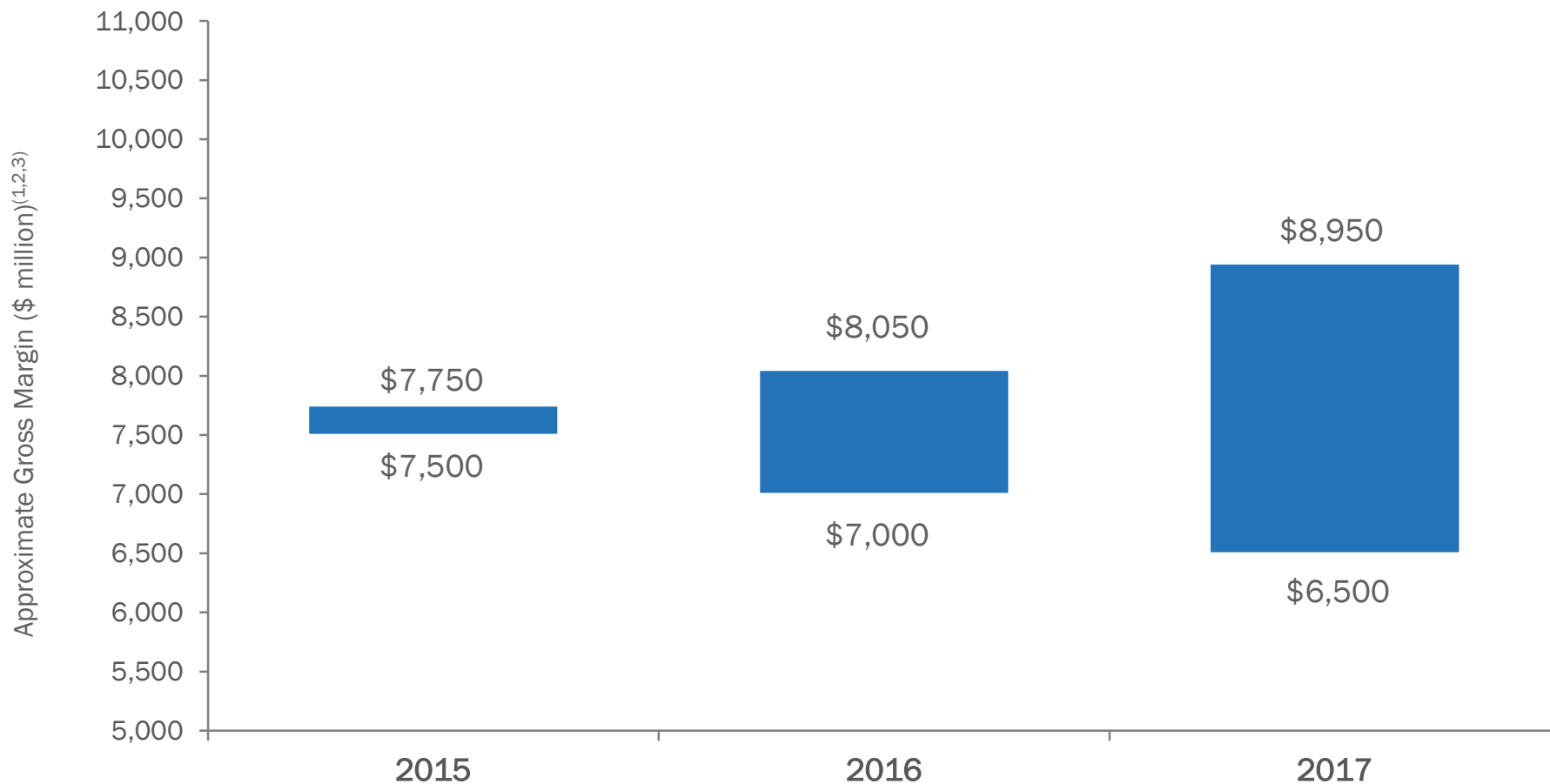
(1) Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 14 refueling outages in 2015, 12 in 2016, and 15 in 2017 at Exelon-operated nuclear plants, and Salem. Expected generation assumes capacity factors of 93.3%, 94.1% and 93.4% in 2015, 2016 and 2017 respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2016 and 2017 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) ⁽¹⁾	2015	2016	2017
Henry Hub Natural Gas (\$/Mmbtu)			
+ \$1/Mmbtu	\$(80)	\$140	\$400
- \$1/Mmbtu	\$90	\$(135)	\$(385)
NiHub ATC Energy Price			
+ \$5/MWh	-	\$135	\$305
- \$5/MWh	-	\$(135)	\$(305)
PJM-W ATC Energy Price			
+ \$5/MWh	\$(10)	\$60	\$145
- \$5/MWh	\$10	\$(55)	\$(140)
NYPP Zone A ATC Energy Price			
+ \$5/MWh	-	\$5	\$20
- \$5/MWh	-	\$(10)	\$(20)
Nuclear Capacity Factor			
+/- 1%	+/- \$20	+/- \$45	+/- \$40

(1) Based on June 30, 2015 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 2016 and 2017 do not represent earnings guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years; The price distributions that generate this range are calibrated to market quotes for power, fuel, load following products, and options as of June 30, 2015
- (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. See Slide 29 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 2016 Gross Margin

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Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	<div>← \$5.7 billion →</div>					
(B)	Expected Generation (TWh)	97.3	63.0	16.3	9.3	12.6	
(C)	Hedge % (assuming mid-point of range)	73.5%	83.5%	94.5%	77.5%	68.5%	
(D=B*C)	Hedged Volume (TWh)	71.5	52.6	15.4	7.2	8.6	
(E)	Effective Realized Energy Price (\$/MWh)	\$34.00	\$45.50	\$10.00	\$41.50	\$19.00	
(F)	Reference Price (\$/MWh)	\$30.65	\$38.27	\$3.82	\$34.03	\$8.77	
(G=E-F)	Difference (\$/MWh)	\$3.35	\$7.23	\$6.18	\$7.47	\$10.23	
(H=D*G)	Mark-to-market value of hedges (\$ million) ⁽¹⁾	\$240	\$380	\$95	\$55	\$90	
(I=A+H)	Hedged Gross Margin (\$ million)	\$6,600					
(J)	Power New Business / To Go (\$ million)	\$450					
(K)	Non-Power Margins Executed (\$ million)	\$200					
(L)	Non-Power New Business / To Go (\$ million)	\$250					
(N=I+J+K+L)	Total Gross Margin ⁽²⁾	\$7,500 million					

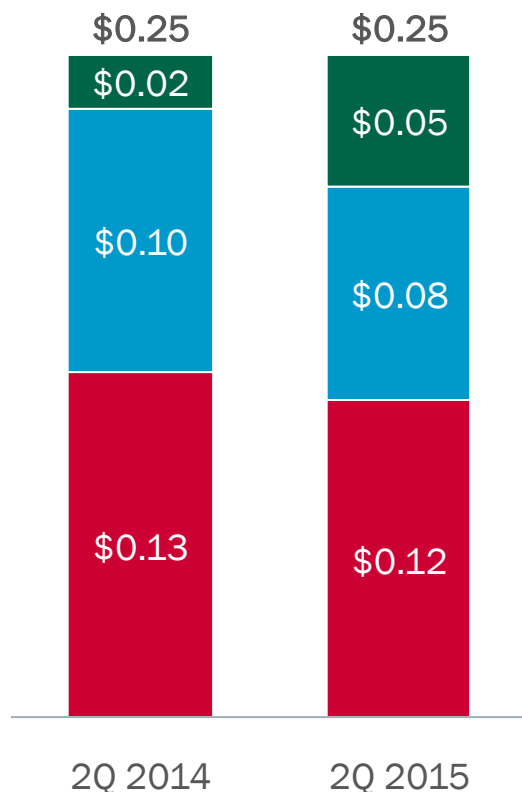
(1) Mark-to-market rounded to the nearest \$5 million

(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. See Slide 29 for a Non-GAAP to GAAP reconciliation of Total Gross Margin.

Additional Disclosures

Exelon Utilities Adjusted Operating EPS Contribution⁽¹⁾

■ BGE ■ PECO ■ ComEd



Key Drivers – 2Q15 vs. 2Q14:

BGE (+0.03):

- Decreased uncollectible expense: \$0.02
- Increased distribution revenue due to increased rates: \$0.01

PECO (-0.02):

- Increased storm costs: (\$0.01)

ComEd (-0.01):

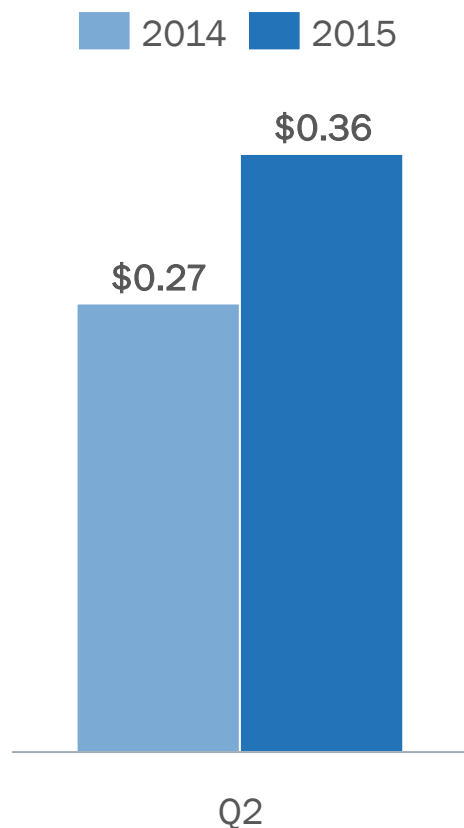
- Unfavorable weather⁽²⁾: \$(0.01)
- Increased distribution⁽²⁾ earnings due to increased capital investments: \$0.01

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) 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⁽¹⁾



Key Drivers – Q2 2015 vs. Q2 2014

ExGen (+0.09)

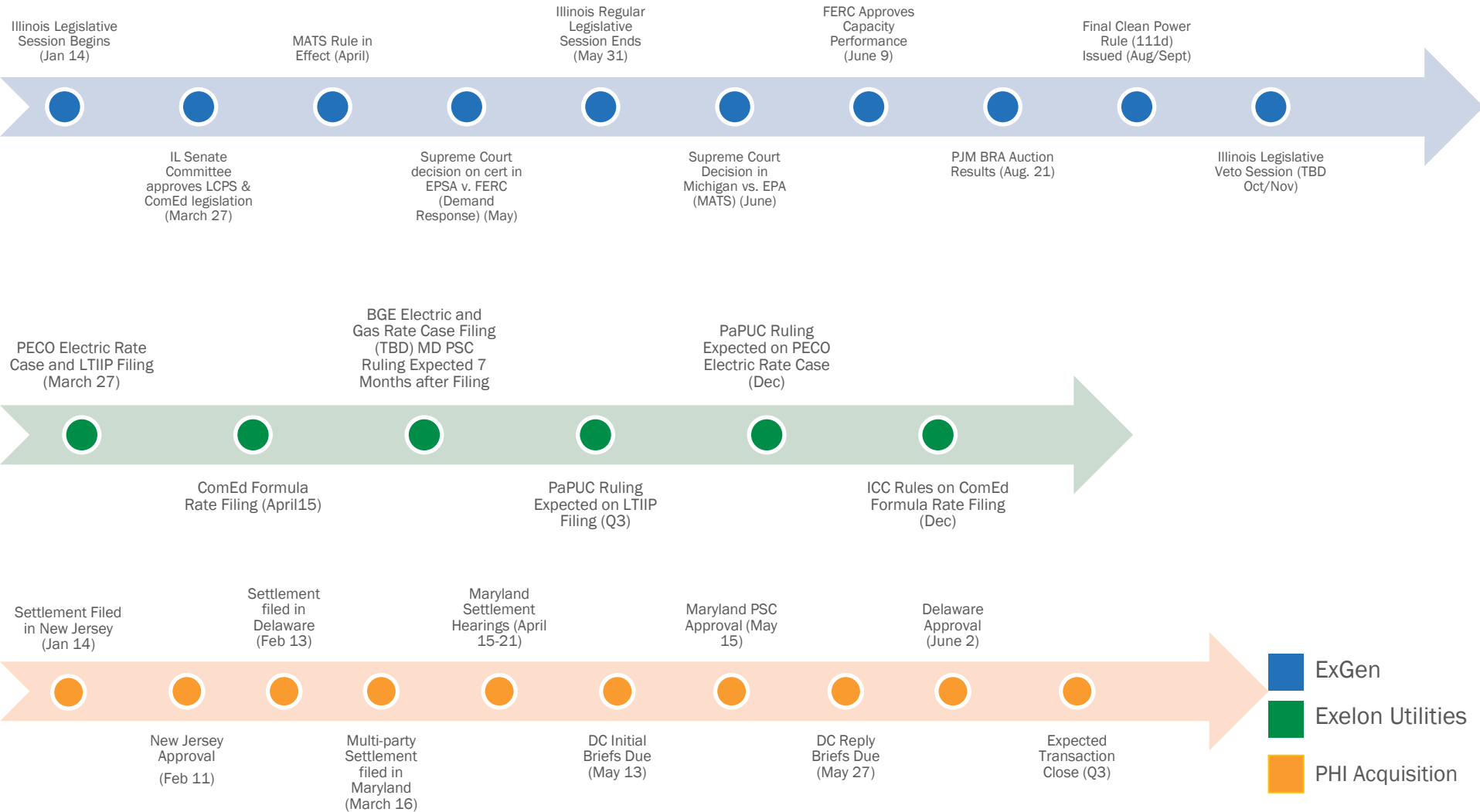
- Increased RNF: \$0.10
 - Increased nuclear output in 2015, primarily due to a reduction in outage days: \$0.07
 - Favorability from portfolio management optimization activities, partially offset by the absence of various generating units sold in 2014 and 2015: \$0.02
 - Increased capacity revenue: \$0.01
- Higher realized NTDF gains: \$0.03
- Increased income tax expense due to decreased domestic production activities deduction: (\$0.03)
- Increased interest expense: (\$0.01)

(excludes Salem)	Q2 2014 Actual	Q2 2015 Actual
Planned Refueling Outage Days	108	71
Non-refueling Outage Days	44	18
Nuclear Capacity Factor	91.8%	93.1%

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.

2015 Regulatory and Legislative Timelines



ComEd April 2015 Distribution Formula Rate

The 2015 distribution formula rate filing establishes the net revenue requirement used to set the rates that will take effect in January 2016 after the Illinois Commerce Commission's (ICC's) review. There are two components to the annual distribution formula rate filing:

- **Filing Year:** Based on prior year costs (2014) and current year (2015) projected plant additions.
- **Annual Reconciliation:** For the prior calendar year (2014), this amount reconciles the revenue requirement reflected in rates during the prior year (2014) in effect to the actual costs for that year. The annual reconciliation impacts cash flow in the following year (2016) but the earnings impact has been recorded in the prior year (2014) as a regulatory asset.

Docket #	15-0287
Filing Year	2014 Calendar Year Actual Costs and 2015 Projected Net Plant Additions are used to set the rates for calendar year 2016. Rates currently in effect (docket 14-0312) for calendar year 2015 were based on 2013 actual costs and 2014 projected net plant additions
Reconciliation Year	Reconciles Revenue Requirement reflected in rates during 2014 to 2014 Actual Costs Incurred. Revenue requirement for 2014 is based on docket 13-0318 (2012 actual costs and 2013 projected net plant additions) approved in December 2013 and reflects the impacts of PA 98-0015 (SB9)
Common Equity Ratio	~ 46% for both the filing and reconciliation year
ROE	9.14% for the filing year (2014 30-yr Treasury Yield of 3.34% + 580 basis point risk premium) and 9.09% for the reconciliation year (2014 30-yr Treasury Yield of 3.34% + 580 basis point risk premium – 5 basis points performance metrics penalty). For 2015 and 2016, the actual allowed ROE reflected in net income will ultimately be based on the average of the 30-year Treasury Yield during the respective years plus 580 basis point spread, absent any metric penalties
Requested Rate of Return	~ 7% for both the filing and reconciliation years
Rate Base ⁽¹⁾	\$8,277 million – Filing year (represents projected year-end rate base using 2014 actual plus 2015 projected capital additions). 2015 and 2016 earnings will reflect 2015 and 2016 year-end rate base respectively. \$7,082 million - Reconciliation year (represents year-end rate base for 2014)
Revenue Requirement Decrease ⁽¹⁾	\$54M decrease (\$145M decrease due to the 2014 reconciliation offset by a \$91M increase related to the filing year). The 2014 reconciliation impact on net income was recorded in 2014 as a regulatory asset.
Timeline	<ul style="list-style-type: none"> • 04/15/15 Filing Date • 240 Day Proceeding • ICC order expected to be issued by December 11, 2015

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

⁽¹⁾ Amounts represent ComEd's position filed in rebuttal testimony on July 22, 2015.

Note: Disallowance of any items in the 2015 distribution formula rate filing could impact 2015 earnings in the form of a regulatory asset adjustment.

PECO Electric Distribution Rate Case

Docket #	R-2015-2468981
Fully Projected Future Test Year	2016
Common Equity Ratio	53%
Requested Return on Equity	10.95%
Overall Rate of Return	8.2%
Proposed Rate Base	\$4.1B
Revenue Requirement Increase Ask	\$190M
System Average Increase as % of overall bill	4.4%
Timeline	<ul style="list-style-type: none"> • 3/27/15 – PECO filed electric distribution rate case with PaPUC • 8/11/15 – 8/14/15 – Evidentiary Hearings • October 2015 – ALJ Recommended Decision • December 2015 – PUC Decision • Increased rates effective on January 1, 2016
Basis for Rate Case	<ul style="list-style-type: none"> • Since last rate case (2010): <ul style="list-style-type: none"> – Electric Distribution Rate base increased by one third (approximately \$1B) – Sales declined by 0.6% – Operating expenses were essentially flat (less than 1% annually) • Proposed investment maintains strong reliability performance with targeted investment to address pockets with reliability issues

First Electric Distribution Rate Case since 2010

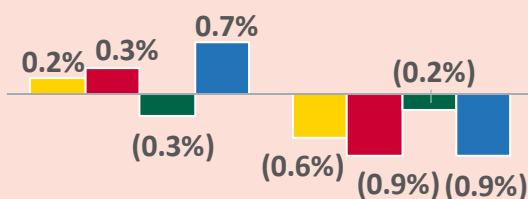
PECO Electric LTIP - System 2020

- PECO filed its Electric Long Term Infrastructure Improvement Plan (“LTIP”) along with its associated recovery mechanism the Distribution System Improvement Charge (“DSIC”) on March 27, 2015 (with Electric Distribution Rate Case)
 - LTIP includes \$275 million in incremental capital spending from 2016-2020 focusing on the following areas:
 - Cable Replacement
 - Storm Hardening Programs
 - Substation replacement and upgrades
 - DSIC mechanism will allow recovery of eligible LTIP spend between rate cases if the electric distribution ROE falls below the DSIC ROE established by PaPUC. The current Electric DSIC ROE is 10.0%.
 - Expected approval in 3Q15
- PECO also proposed the concept of constructing one or more pilot microgrid projects as part of a future LTIP update (\$50-\$100M). The objective is to evaluate and test emerging microgrid technologies that could enhance reliability and resiliency by replacing obsolete infrastructure as an alternative to traditional solutions.

Exelon Utilities Load

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

ComEd



2014

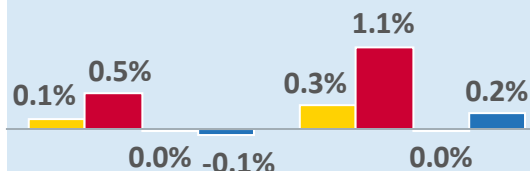
2015E

Chicago GMP 1.7%

Chicago Unemployment 6.2%

2015 load growth is lower than 2014 (impacts of energy efficiency partially offset by slowly improving economy) with Residential and Large C&I trending downward

PECO



2014

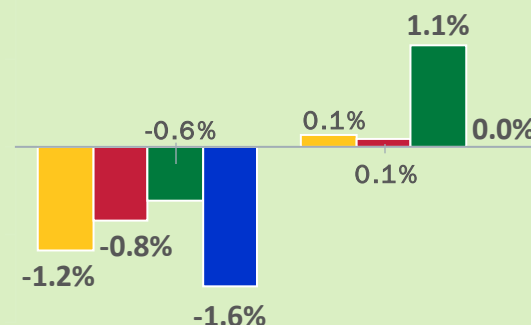
2015E

Philadelphia GMP 1.7%

Philadelphia Unemployment 5.3%

2015 load growth is driven by modest economic growth coupled with solid residential customer growth, partially offset by energy efficiency

BGE



2014

2015E

Baltimore GMP 1.3%

Baltimore Unemployment 5.6%

2015 load growth is greater than 2014, attributable to slowly improving economic conditions and moderate customer growth, partially offset by energy efficiency

Notes: Data is not adjusted for leap year. Source of economic outlook data is IHS (June 2015) and Bureau of Economic Analysis. Assumes 2015 GDP of 2.1% and U.S. unemployment of 5.3%. 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.

Appendix

Reconciliation of Non-GAAP Measures

2Q GAAP EPS Reconciliation

<u>Three Months Ended June 30, 2014</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>Other</u>	<u>Exelon</u>
2014 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.27	\$0.13	\$0.10	\$0.02	\$-	\$0.51
Mark-to-market impact of economic hedging activities	(0.01)	-	-	-	-	(0.01)
Unrealized gains related to NDT fund investments	0.09	-	-	-	-	0.09
Merger and integration costs	(0.02)	-	-	-	(0.01)	(0.03)
Amortization of commodity contract intangibles	(0.03)	-	-	-	-	(0.03)
Long-lived asset impairment	(0.06)	-	-	-	(0.02)	(0.08)
Gain on CENG integration	0.18	-	-	-	-	0.18
CENG Non-Controlling Interest	(0.03)	-	-	-	-	(0.03)
2Q 2014 GAAP Earnings (Loss) Per Share	\$0.39	\$0.13	\$0.10	\$0.02	\$-	\$0.60
<u>Three Months Ended June 30, 2015</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>Other</u>	<u>Exelon</u>
2015 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.36	\$0.12	\$0.08	\$0.05	\$(0.01)	\$0.59
Mark-to-market impact of economic hedging activities	0.16	-	-	-	-	0.16
Unrealized losses related to NDT fund investments	(0.06)	-	-	-	-	(0.06)
Merger and integration costs	(0.01)	-	-	-	(0.01)	(0.02)
Mark-to-market impact of PHI merger related interest rate swaps	-	-	-	-	0.08	0.08
Amortization of commodity contract intangibles	(0.01)	-	-	-	-	(0.01)
Long-lived asset impairment	-	-	-	-	(0.02)	(0.02)
CENG Non-Controlling Interest	0.02	-	-	-	-	0.02
2Q 2015 GAAP Earnings (Loss) Per Share	\$0.46	\$0.12	\$0.08	\$0.05	\$0.04	\$0.74

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

2Q YTD GAAP EPS Reconciliation

Six Months Ended June 30, 2014	ExGen	ComEd	PECO	BGE	Other	Exelon
2014 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.57	\$0.24	\$0.20	\$0.12	\$(0.01)	\$1.12
Mark-to-market impact of economic hedging activities	(0.52)	-	-	-	-	(0.52)
Unrealized gains related to NDT fund investments	0.10	-	-	-	-	0.10
Merger and integration costs	(0.03)	-	-	-	(0.01)	(0.04)
Amortization of commodity contract intangibles	(0.06)	-	-	-	-	(0.06)
Long-lived asset impairment	(0.06)	-	-	-	(0.02)	(0.08)
Tax Settlements	0.04	-	-	-	-	0.04
Gain on CENG integration	0.18	-	-	-	-	0.18
CENG Non-Controlling Interest	(0.03)	-	-	-	-	(0.03)
2Q 2014 GAAP Earnings (Loss) Per Share	\$0.18	\$0.24	\$0.20	\$0.12	\$(0.04)	\$0.71
Six Months Ended June 30, 2015	ExGen	ComEd	PECO	BGE	Other	Exelon
2015 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.71	\$0.22	\$0.24	\$0.18	\$(0.05)	\$1.30
Mark-to-market impact of economic hedging activities	0.27	-	-	-	-	0.27
Unrealized losses related to NDT fund investments	(0.04)	-	-	-	-	(0.04)
Merger and integration costs	(0.01)	-	-	-	(0.03)	(0.04)
Mark-to-market impact of PHI merger related interest rate swaps	-	-	-	-	0.03	0.03
Amortization of commodity contract intangibles	0.02	-	-	-	-	0.02
Long-lived asset impairment	-	-	-	-	(0.02)	(0.02)
Midwest Generation bankruptcy recoveries	0.01	-	-	-	-	0.01
CENG Non-Controlling Interest	0.01	-	-	-	-	0.01
2Q 2015 GAAP Earnings (Loss) Per Share	\$0.97	\$0.22	\$0.24	\$0.18	\$(0.07)	\$1.54

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

GAAP to Operating Adjustments

- **Exelon's 2015 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
 - Certain costs incurred associated with the Integrys and pending Pepco Holdings, Inc. acquisitions
 - Mark-to-market adjustments from forward-starting interest rate swaps related to anticipated financing for the pending PHI acquisition
 - Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at the date of acquisition of Integrys in 2014
 - Impairment of investment in long-term generating leases
 - Generation's non-controlling interest related to CENG exclusion items
 - Other unusual items

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

ExGen Total Gross Margin Reconciliation to GAAP

Total Gross Margin Reconciliation (in \$M) ⁽⁴⁾	2015	2016	2017
Revenue Net of Purchased Power and Fuel Expense⁽¹⁾⁽⁵⁾	\$8,200	\$8,100	\$8,300
Other Revenues ⁽²⁾	\$(250)	\$(250)	\$(250)
Direct cost of sales incurred to generate revenues for certain Constellation businesses ⁽³⁾	\$(300)	\$(350)	\$(450)
Total Gross Margin (Non-GAAP, as shown on slide (6))	\$7,650	\$7,500	\$7,600

(1) 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

(2) 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

(3) Reflects the cost of sales and depreciation expense of certain Constellation businesses of Generation

(4) All amounts rounded to the nearest \$50M

(5) Excludes the impact of the operating exclusion for mark-to-market due to the volatility and unpredictability of the future changes to power prices