UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

August 9, 2016
Date of Report (Date of earliest event reported)

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** **(a Maryland corporation)** 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201 (410) 234-5000	52-0280210
001-31403	**PEPCO HOLDINGS LLC** **(a Delaware limited liability company)** 701 Ninth Street, N.W. Washington, D.C. 20068 (202)872-2000	52-2297449
001-01072	**POTOMAC ELECTRIC POWER COMPANY** **(a District of Columbia and Virginia corporation)** 701 Ninth Street, N.W. Washington, D.C. 20068 (202)872-2000	53-0127880
001-01405	**DELMARVA POWER & LIGHT COMPANY** **(a Delaware and Virginia corporation)** 500 North Wakefield Drive, 2nd Floor Newark, DE 19702 (202)872-2000	51-0084283
001-03559	**ATLANTIC CITY ELECTRIC COMPANY** **(a New Jersey corporation)** 500 North Wakefield Drive, 2nd Floor Newark, DE 19702 (202)872-2000	21-0398280

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 7 – Regulation FD

Item 7.01. Regulation FD Disclosure.

On August 10, 2016, Exelon Corporation (Exelon) is hosting an Analyst Day beginning at 8:45 AM EST (7:45 AM CT). A copy of the Analyst Day presentation is attached hereto as Exhibit 99.1. This Form 8-K and the attached exhibits are provided under Items 7.01 and 9.01 of Form 8-K and are furnished to, but not filed with, the Securities and Exchange Commission.

The Analyst Day will be webcast and will be available at: https://publishingsp.www.exeloncorp.com/newsroom/events/analyst-day-2016.

Webcast replays will be available until November 10, 2016 at the same web address.

Section 9 – Financial Statements and Exhibits

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits*.

Exhibit No.	Description
99.1	Analyst day presentation slides

* * * * *

This combined Current Report on Form 8-K is being furnished separately by Exelon, 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). Information contained herein relating to any individual Registrant has been furnished by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

This report 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 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; (3) Exelon's Second Quarter 2016 Quarterly Report on Form 10-Q 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 18 and (4) 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 report. 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 report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

EXELON CORPORATION

/s/ Jonathan W. Thayer

Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer
Exelon Corporation

EXELON GENERATION COMPANY, LLC

/s/ Bryan P. Wright

Bryan P. Wright
Senior Vice President and Chief Financial Officer Exelon Generation Company, LLC

COMMONWEALTH EDISON COMPANY

/s/ Joseph R. Trpik, Jr.

Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer
Commonwealth Edison Company

PECO ENERGY COMPANY

/s/ Phillip S. Barnett

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
PECO Energy Company

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ David M. Vahos

David M. Vahos
Senior Vice President, Chief Financial Officer and Treasurer
Baltimore Gas and Electric Company

PEPCO HOLDINGS LLC

/s/ Donna J. Kinzel

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer,
Pepco Holdings LLC

POTOMAC ELECTRIC POWER COMPANY

/s/ Donna J. Kinzel

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer,
Potomac Electric Power Company

DELMARVA POWER & LIGHT COMPANY

/s/ Donna J. Kinzel

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer,
Delmarva Power & Light Company

ATLANTIC CITY ELECTRIC COMPANY

/s/ Donna J. Kinzel

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer,
Atlantic City Electric Company

August 9, 2016

EXHIBIT INDEX

Exhibit No.	Description
99.1	Analyst day presentation slides


Exhibit 99.1
Exelon
Building Enduring Value

Welcome and Agenda

Dan Eggers
Senior Vice President, Investor Relations

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; (3) Exelon's Second Quarter 2016 Quarterly Report on Form 10-Q 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 18; and (4) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this presentation. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

Non-GAAP Financial Measures

Exelon reports its financial results in accordance with accounting principles generally accepted in the United States (GAAP). Exelon supplements the reporting of financial information determined in accordance with GAAP with certain non-GAAP financial measures, including adjusted (non-GAAP) operating earnings, adjusted (non-GAAP) operating and maintenance expense, total gross margin, earnings before interest, taxes, depreciation and amortization (EBITDA), and adjusted cash flow from operations (non-GAAP) or free cash flow. Adjusted (non-GAAP) 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 merger and integration costs, certain costs incurred associated with the PHI acquisition, merger commitments related to the settlement of the PHI acquisition, the impairment of certain long-lived assets, plant retirements and divestitures, costs related to the cost management program, and the non-controlling interest in CENG. Adjusted (non-GAAP) operating and maintenance expense excludes regulatory operating and maintenance costs for the utility businesses and direct cost of sales for certain Constellation businesses, decommissioning costs that do not affect profit and loss, and the impact from operating and maintenance expense related to variable interest entities at Generation. 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, the operating services agreement with Fort Calhoun, variable interest entities and net of direct cost of sales for certain Constellation businesses. EBITDA is defined as earnings before interest, taxes, depreciation and amortization, including nuclear fuel amortization expense. Adjusted cash flow from operations (non-GAAP) or free cash flow primarily includes net cash flows from operating activities and net cash flows from investing activities excluding capital expenditures at ownership and nuclear fuel expense. Due to the forward-looking nature of any forecasted non-GAAP measures, information to reconcile the forecast adjusted (non-GAAP) measures to the most directly comparable GAAP measure is not currently available, as management is unable to project all of these items for future periods.

Non-GAAP Financial Measures Continued

This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of Exelon's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods.

These non-GAAP financial measures are not a presentation defined under GAAP and may not be comparable to other companies' presentation. Exelon has provided these non-GAAP financial measure 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. Reconciliations of these non-GAAP measures to the most comparable GAAP measures are provided in the footnotes, appendices and attachments to this presentation.

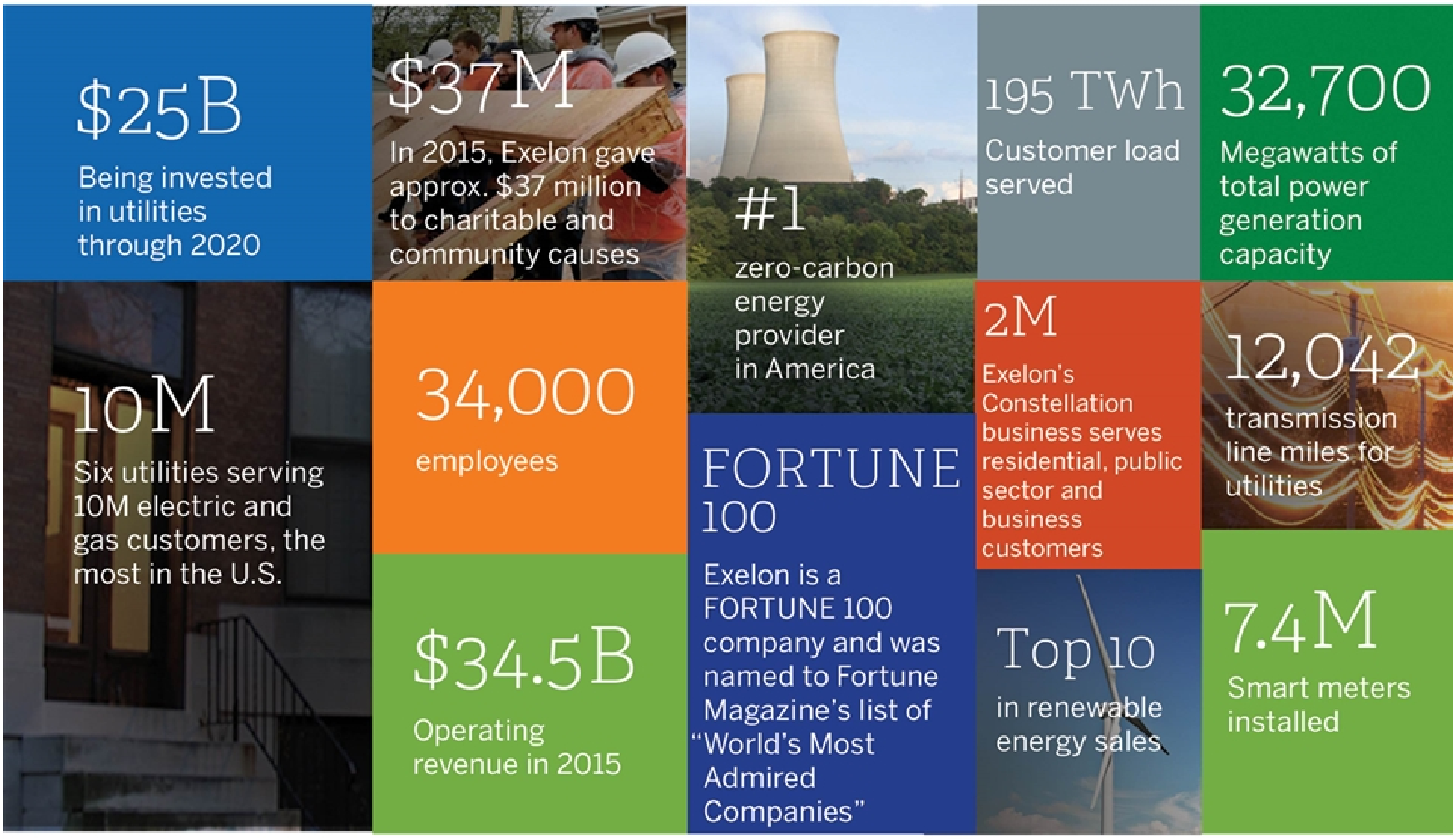
Agenda

Time (ET)	Presentation Topic	Presenter	Total Time
8:45 – 8:50	**Welcome & Introductions**	Dan Eggers	5 minutes
8:50 – 9:10	**Exelon Overview**	Chris Crane	20 minutes
9:10 – 10:25	**Exelon Utilities**	Denis O'Brien Anne Pramaggiore Calvin Butler Craig Adams Dave Velazquez Q&A	75 minutes
10:25 – 10:40	BREAK		15 minutes
10:40 – 11:00	**Exelon's Policy Priorities**	Bill Von Hoene Kathleen Barrón	20 minutes
11:00 – 11:30	**Exelon Generation**	Ken Cornew Joe Nigro	30 minutes
11:30 – 11:45	**Q&A**		15 minutes
11:45 – 12:00	**Financial Update**	Jack Thayer	15 minutes
12:00 – 12:20	**Q&A**		20 minutes
12:20 – 12:30	**Closing**	Chris Crane	10 minutes

Exelon Overview

Chris Crane
President & Chief Executive Officer

Exelon: An Industry Leader



Note: All numbers reflect year-end 2015; 2015 revenue number is Exelon and PHI combined

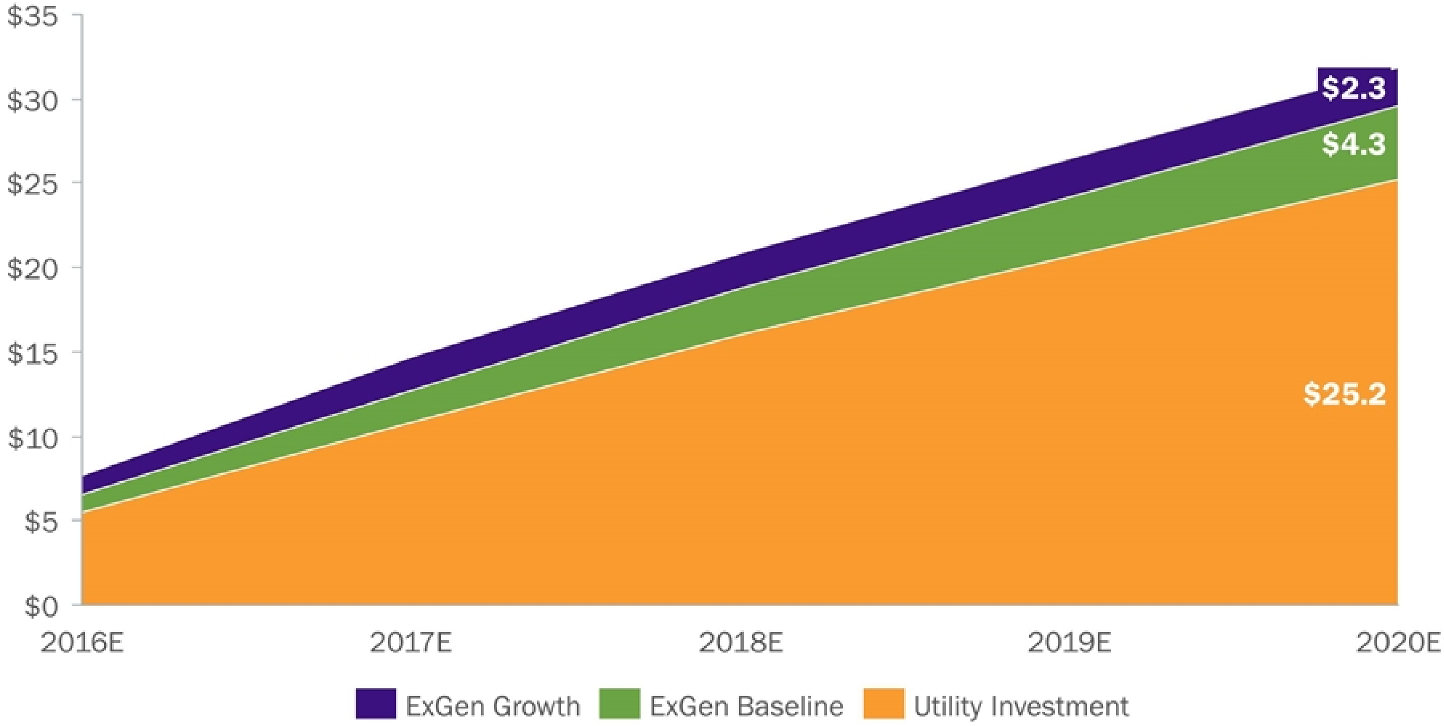
The Exelon Value Proposition

- **Regulated Utility Growth** with utility EPS rising 7-9% annually from 2016-2020 and rate base growth of 6.1%, representing an expanding majority of earnings
- **ExGen's strong free cash generation** will support utility growth while also reducing debt by ~$3B over the next 5 years
- **Optimizing ExGen value by:**
  - Seeking fair compensation for the zero-carbon attributes of our fleet;
  - Closing uneconomic plants;
  - Monetizing assets; and,
  - Maximizing the value of the fleet through our generation to load matching strategy
- **Strong balance sheet is a priority** with all businesses comfortably meeting investment grade credit metrics through the 2020 planning horizon
- **Capital allocation priorities targeting**:
  - Organic utility growth;
  - Return of capital to shareholders with 2.5% annual dividend growth through 2018[1],
  - Debt reduction; and,
  - Modest contracted generation investments

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

Capital Investment Concentrated on Exelon Utilities

Cumulative Capital Expenditures 2016-2020 ($B)

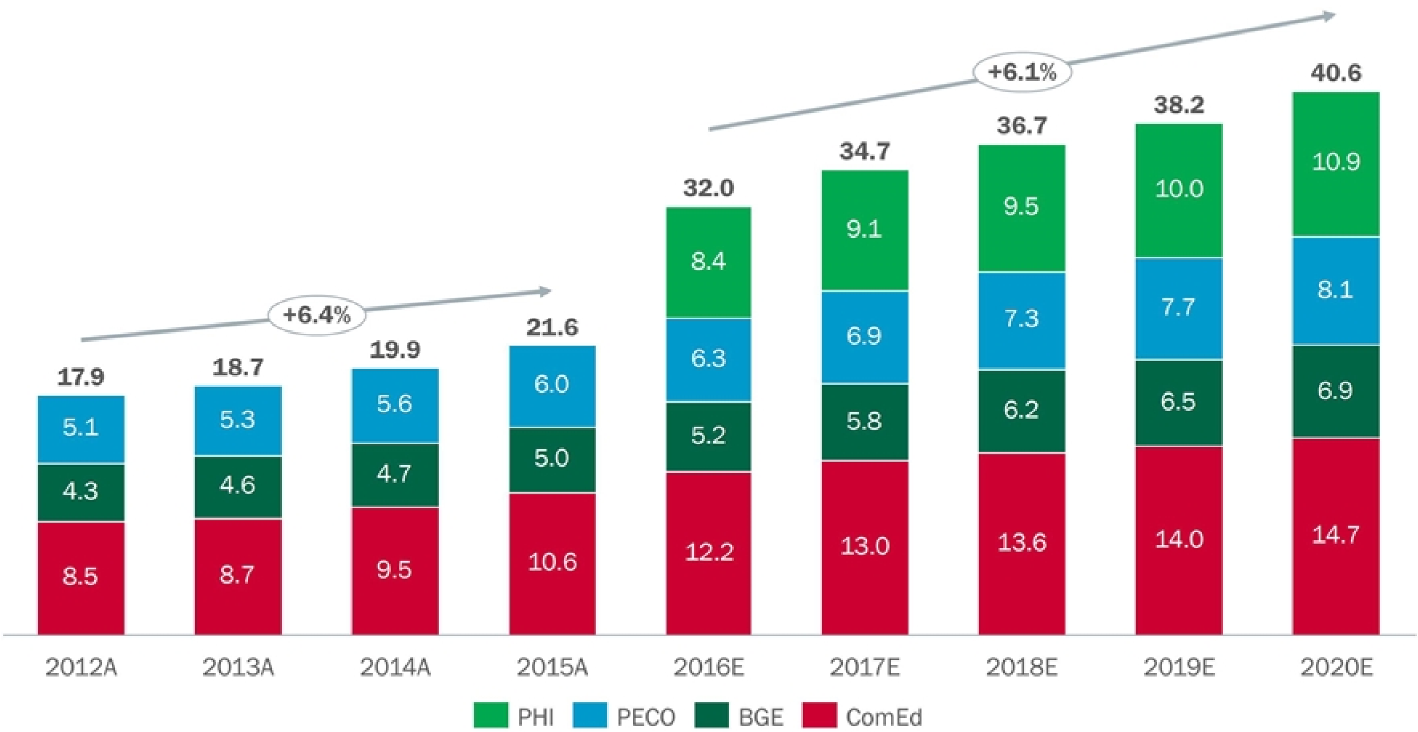


Utilities make up ~80% of capital investment from 2016-2020

Note: ExGen reflects cash capital expenditures with CENG at 100% and excludes Nuclear Fuel and merger commitments

Driving Strong Rate Base Growth

Exelon Utilities Rate Base 2012-2020 ($B)

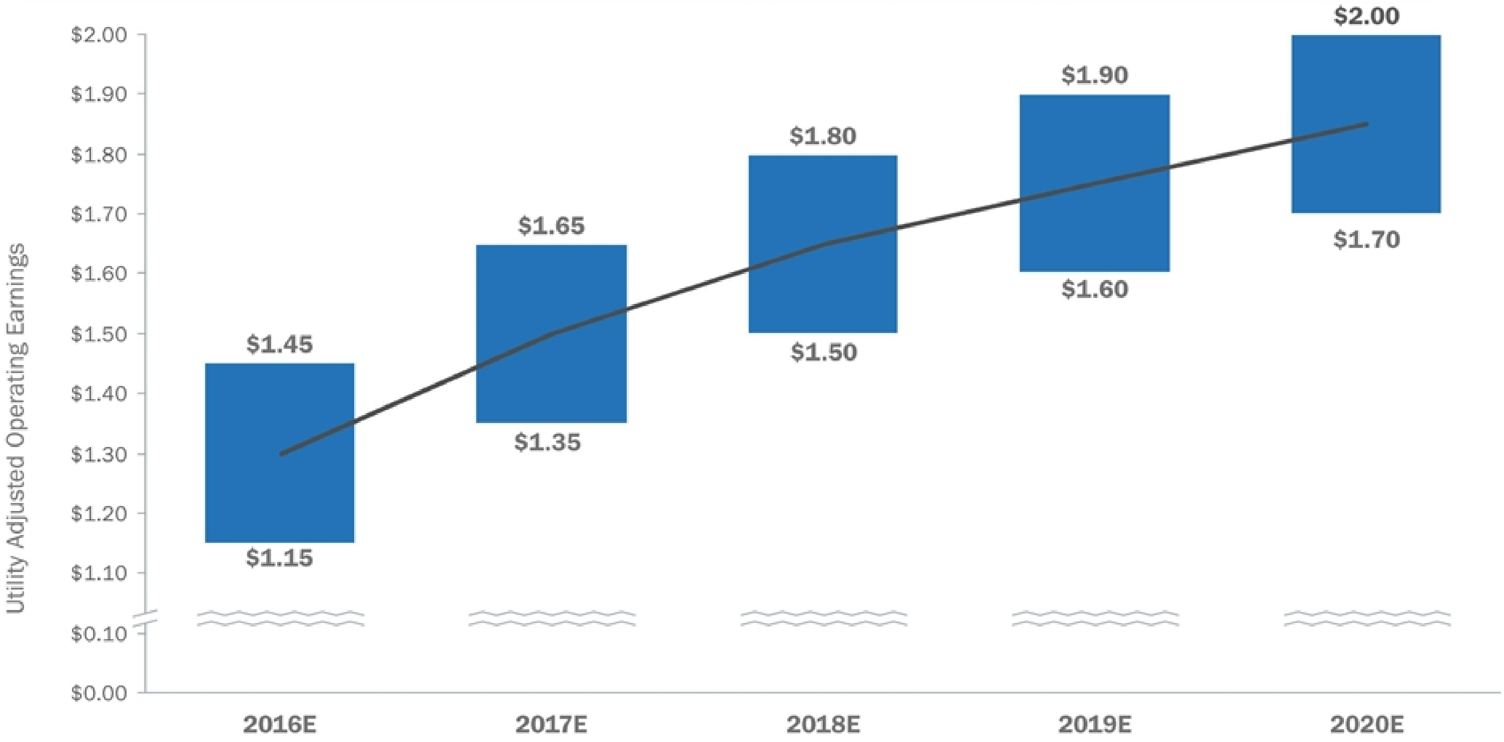


Exelon Utilities delivering strong rate base growth of 6.1% annually over planning period

Note: All numbers denote year-end rate base and may not add due to rounding

Exelon Utilities EPS Growth of 7-9% to 2020

Exelon Utilities Operating Earnings 2016-2020



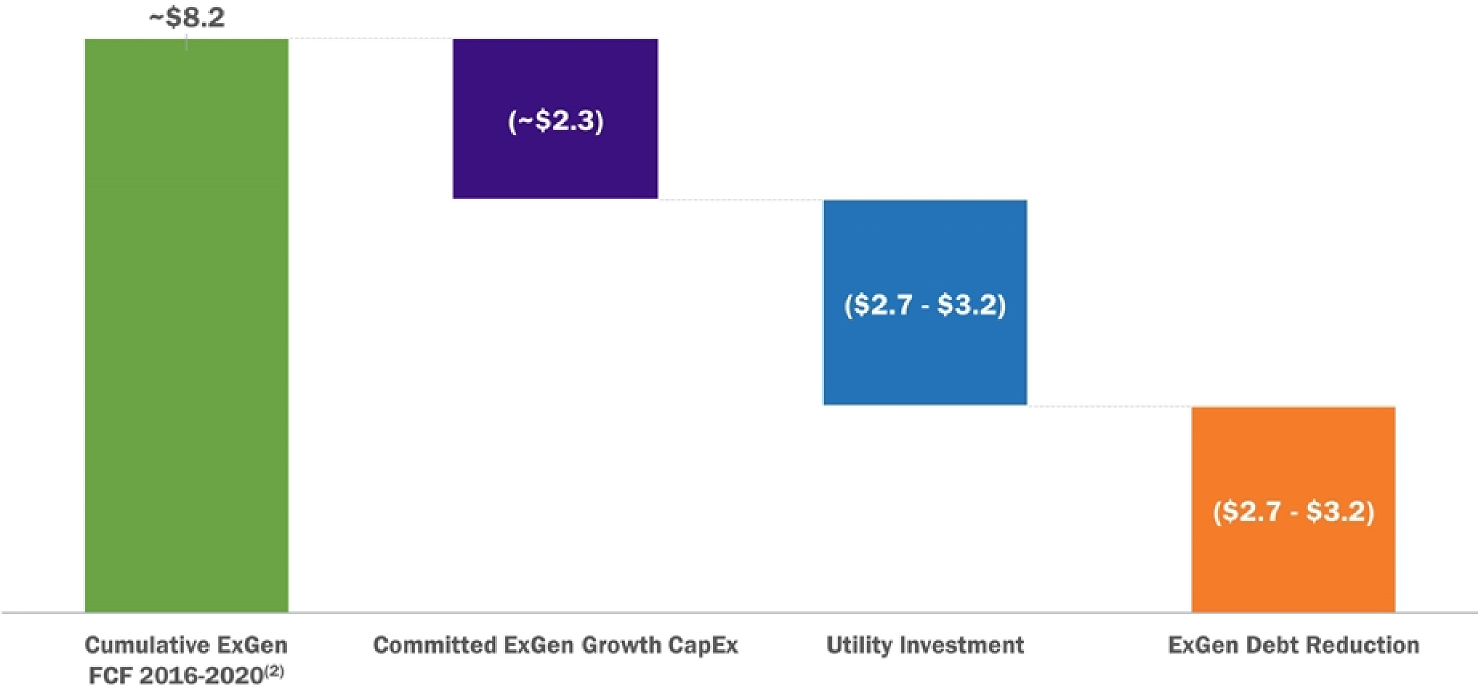
Rate base growth combined with PHI ROE improvement drives EPS growth

Note: Reflects GAAP operating earnings except for 2016. 2016 GAAP EPS range would be $0.65 to $0.95. 2016 adjusted (non-GAAP) operating earnings include adjustments to exclude $0.40 for merger commitments and $0.10 of merger integration costs. Includes after-tax interest expense held at Corporate for debt associated with existing utility investment. 2016 estimate normalized to include a full year for PHI.

Exelon.

ExGen's Strong Free Cash Flow Supports Utility Growth and Debt Reduction

2016-2020 Exelon Generation Free Cash Flow(1,2,3) and Uses of Cash ($B)

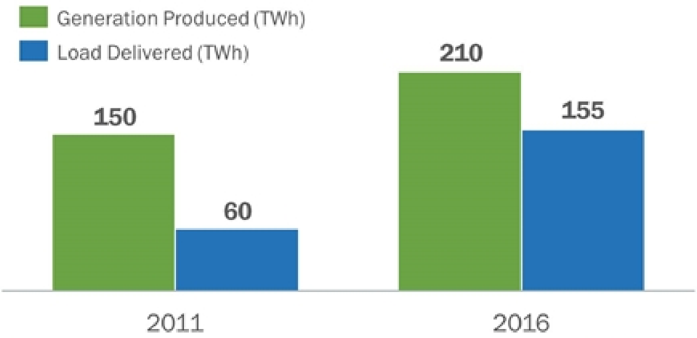


Redeploying Exelon Generation's free cash flow to maximize shareholder value

(1) Free Cash Flow is a non-GAAP Measure. See slide 168 for a reconciliation of free cash flow to the most comparable GAAP measures.
(2) Cumulative Free Cash Flow is a midpoint of a range based on June 30, 2016 market prices. It includes ~$700M of other sources including change in margin, tax parent benefit, equity investments, and acquisitions and divestitures.
(3) Approval of Clean Energy Standard (CES) in NY would add up to ~$750M of incremental cash (after-tax) through 2020. This incremental cash is comprised of payments from the CES program ($350M) and additional distributions to Exelon from CENG related to completion of loan repayment and special distribution.

Taking Steps to Improve ExGen's Earnings Consistency

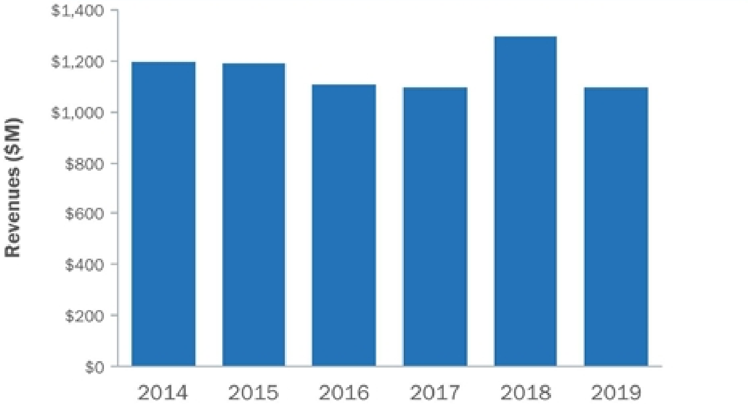
Improving Our Generation to Load Match



Impact of State Nuclear Outcomes(1)

- **New York: $0.08-0.10** per share annually and **~$350M** in additional after-tax cash(2) through 2020 from implementation of Clean Energy Standard (CES) program which includes Zero Emission Credit (ZEC)
- **Illinois**: 2019 run rate of up to **$0.07** per share and up to **$75M** in avoided pre-tax cash losses from retirement of Clinton and Quad Cities

Locked-in PJM Capacity Revenues(3)



Opportunistically Monetize Assets

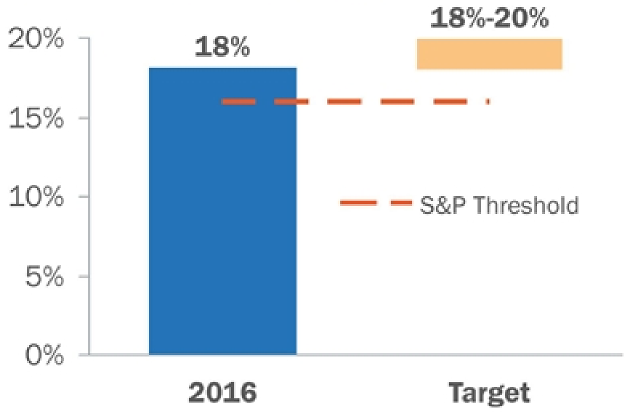
- Realized pre-tax proceeds of **$1.8 Billion** or $600/MW **from 2014 sale of 6 assets**
- Raised **~$3.3B in project finance** since 2011
  - **Including: ~$1,050M** Continental/EGR1 (13 contracted wind assets) and **~$700M** ExGen Texas Power (3,476 MW of gas-fired assets)

(1) Illinois impacts based on February 29, 2016 pricing and excludes decommissioning costs; New York impacts assume ZEC program implementation and that adjusted social cost of carbon is ZEC price for tranche 2
(2) $350M is solely from implementation of CES program and does not include additional cash benefits from CENG loan repayment and special distribution
(3) Prior year capacity revenues are based on the portfolio as it existed in each historical year and is not based on current portfolio. 2014 and beyond excludes Safe Harbor and 2015 and beyond excludes Keystone and Conemaugh which were sold in 2014.

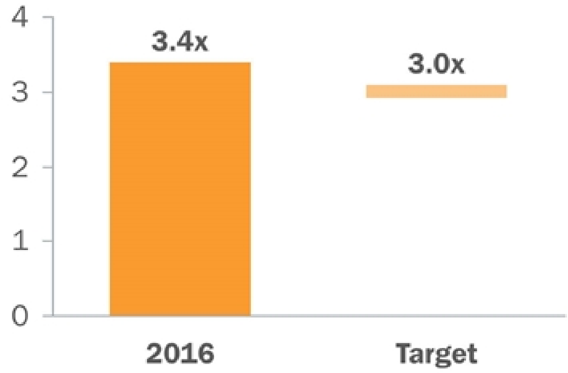
Exelon.

Maintaining Investment Grade Credit Ratings is a Top Financial Priority

Exelon S&P FFO/Debt %(1)(4)



ExGen Debt/EBITDA Ratio(5)



Credit Ratings by Operating Company

Current Ratings (2)(3)	ExCorp	ExGen	ComEd	PECO	BGE	ACE	DPL	Pepco
Moody's	Baa2	Baa2	A2	Aa3	A3	A3	A2	A2
S&P	BBB-	BBB	A-	A-	A-	A	A	A
Fitch	BBB+	BBB	A-	A	A-	A-	A	A-

(1) Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment. FFO/Debt is a non-GAAP measure. Please refer to slide 166 in the appendix for a reconciliation of FFO/Debt to the most comparable GAAP measure.
(2) Current senior unsecured ratings as of June 30, 2016 for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco
(3) All ratings have "Stable" outlook, except for at Moody's, which has ComEd on "Positive" outlook
(4) Exelon Corp downgrade threshold (red dotted line) is based on the S&P Exelon Corp Summary Report; represents minimum level to maintain current Issuer Credit Rating of BBB at Exelon Corp.
(5) Reflects net book debt (YE debt less cash on hand) / adjusted operating EBITDA. EBITDA, a non-GAAP measure, is defined as earnings before interest, taxes, depreciation and amortization. Includes nuclear fuel amortization expense. Please refer to slide 167 for a reconciliation of Debt/EBITDA to the most comparable GAAP measure.

Exelon.

Delivering Value Through Capital Allocation Policy

Our strong balance sheet underpins our capital allocation policy and capital decisions are made to maximize value to our customers and shareholders

We are **returning capital to shareholders** by growing our dividend, targeting 2.5% annual increases through 2018[1] with upside potential beyond

We are **redeploying free cash flow** from Exelon Generation to support:

- **Investing in utilities** where we can earn an appropriate return and will deploy $25B of capital over the next 5 years
- **Retiring debt** with ~$3B targeted at ExGen over the next 5 years
- **Investing in select contracted assets** where we can meaningfully exceed our return thresholds

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

Exelon.

Diverging Paths for Economically Challenged Nuclear Plants

Some Nuclear plants are challenged by persistently low power prices and market designs that do not compensate for their carbon free attributes

New York establishes CES, preserving at-risk nuclear plants, including Ginna and Nine Mile

- **2,600** jobs saved
- **$3B** in NY GDP contributed
- **~$47M** in property taxes preserved
- Prevention of **16MMt** of additional carbon emissions

Illinois fails to reach legislative solution leading to the closure of Clinton and Quad Cities stations

- **4,200** jobs lost
- **$1.2B** in economic activity lost
- **29-43%** of the property tax revenues of surrounding local governments lost
- **20MMt** in additional carbon emissions released

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; New York's Upstate Nuclear Power Plant's Contribution to the State Economy, Mark Berkman and Dean Murphy (The Brattle Group) authors, December 2015

Fostering a Culture of Innovation

Exelon Utilities

Denis O'Brien

Chief Executive Officer, Exelon Utilities

Exelon Utilities Overview

$29.7B
2015 Rate Base

$15.8B
In Revenue

24.1M mi²
Combined Service Territory

7.4 M
Smart Meters Installed

Note: Rate base number is Exelon and PHI combined and denotes year-end

Exelon Utilities (EU) is an Industry Leader

US Utility Customers (millions)

Total Regulated Capital Expenditures 2016-2018 ($B)

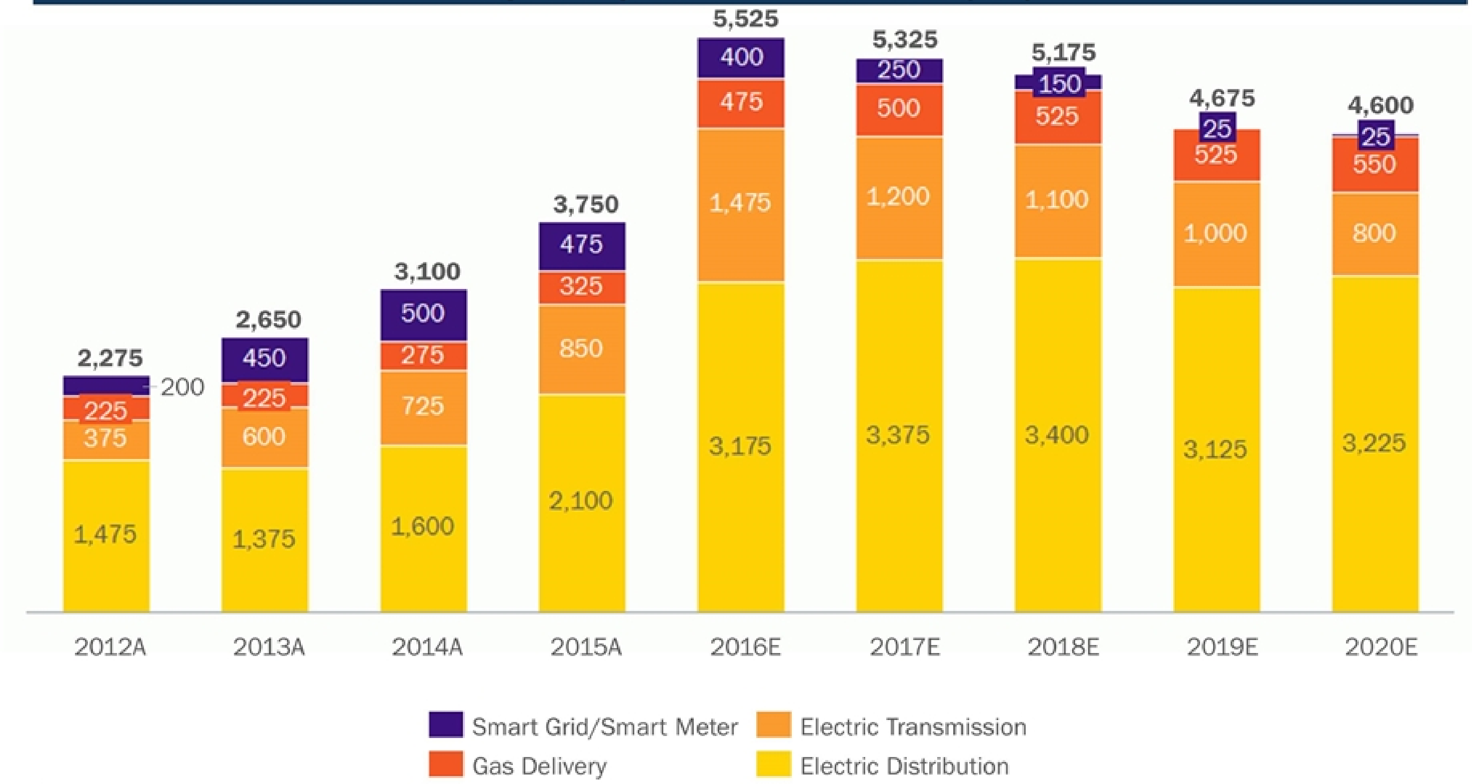
Total Utility Rate Base ($B)

Source: Company Filings
Note: Denotes 2015 year end rate base figures. Exelon figures include PHI.

Exelon.

Deploying Significant Capital for Our Customers

Capital Expenditures 2012-2020 ($M)

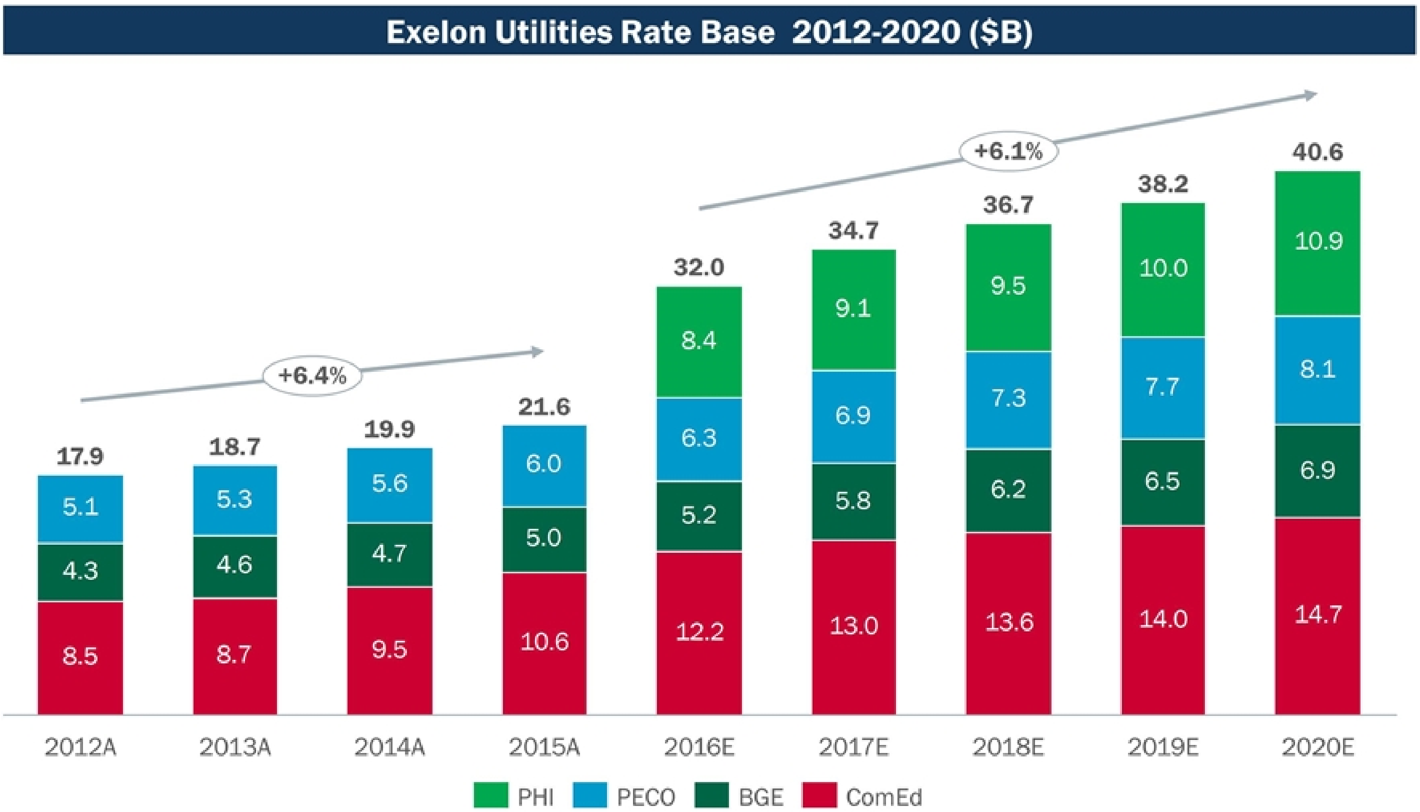


More than $25B of capital is being invested in utilities from 2016-2020

Note: Numbers rounded to nearest $25M; Numbers may not add due to rounding; 2012 Includes a full year of capital spend for BGE; 2016 includes a full year of capital spend for PHI

Exelon.

Driving Strong Rate Base Growth



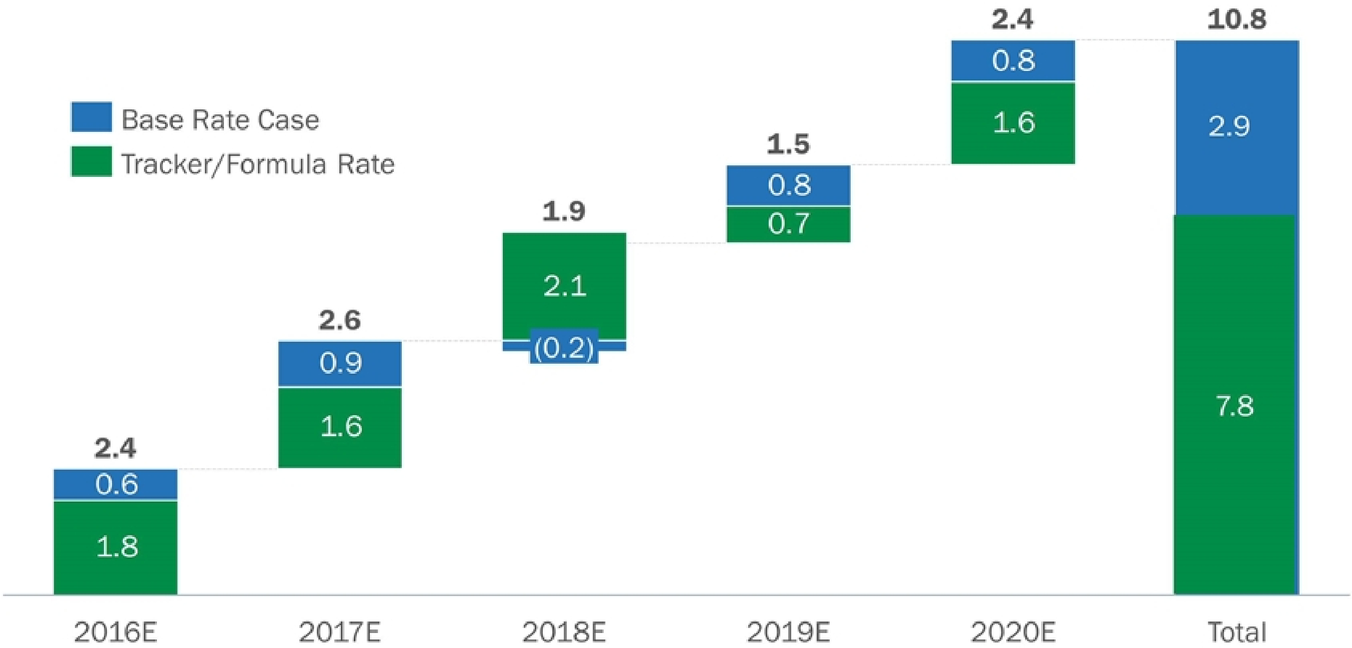
Exelon Utilities delivering strong rate base growth of 6.1% annually over planning period

Note: All numbers denote year-end rate base and may not add due to rounding

Exelon.

Formulaic Mechanisms Cover Bulk of Rate Base Growth

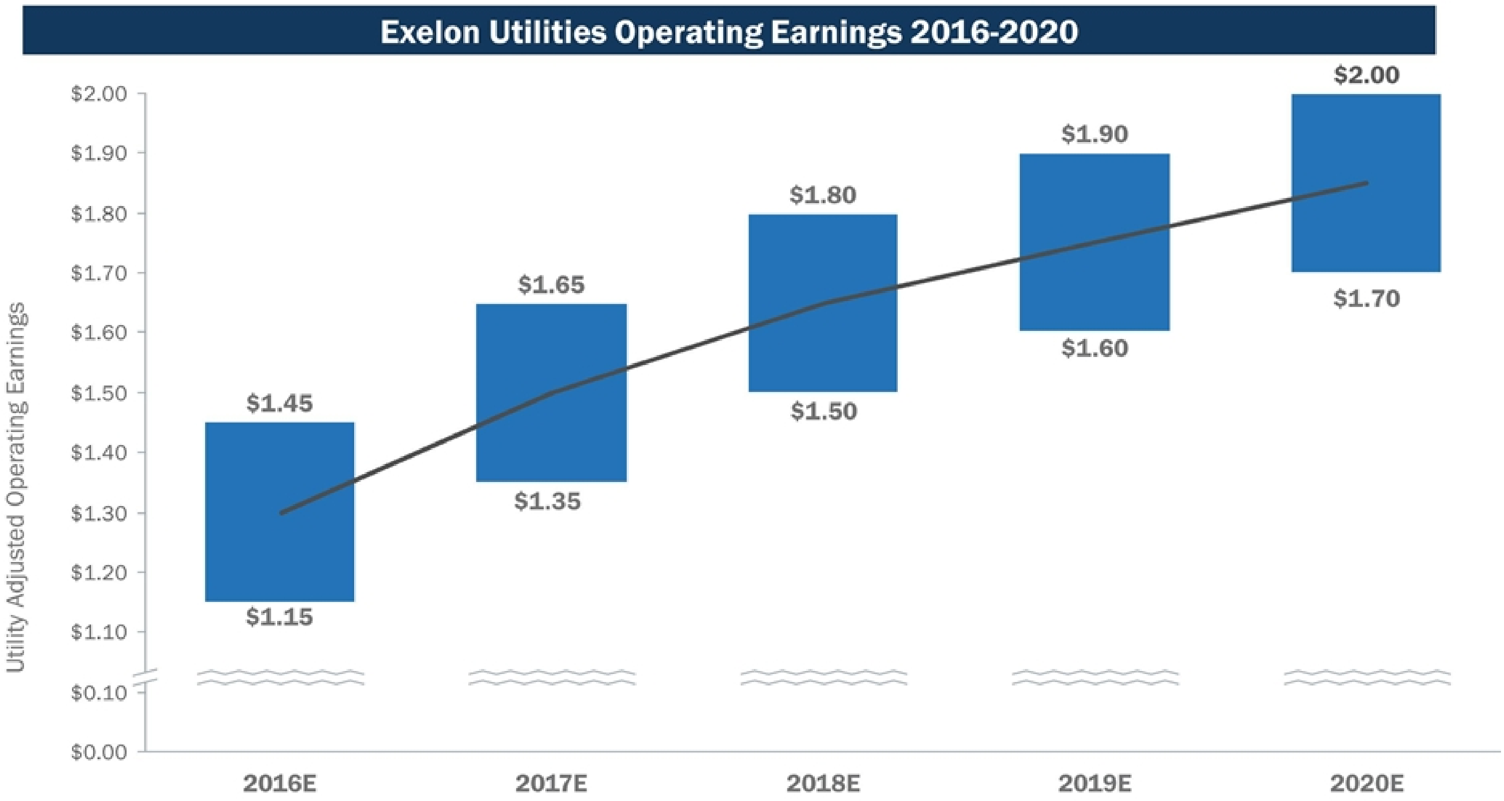
Rate Base Growth Breakout 2016-2020 ($B)



Of the approximately $10.8 billion of rate base growth Exelon Utilities forecast over the next 5 years, more than 70% will be recovered through existing formula and tracker mechanisms

(1) Assumes renewal of ComEd formula rate in 2019; EIMA currently sunsets in 2019
(2) Assumes PECO transmission formula rate beginning in 2018; base rate base decrease due to reclassification of transmission rate base growth at PECO

Exelon Utilities EPS Growth of 7-9% to 2020



Rate base growth combined with PHI ROE improvement drives EPS growth

Note: Reflects GAAP operating earnings except for 2016. 2016 GAAP EPS range would be $0.65 to $0.95. 2016 adjusted (non-GAAP) operating earnings include adjustments to exclude $0.40 for merger commitments and $0.10 of merger integration costs. Includes after-tax interest expense held at Corporate for debt associated with existing utility investment. 2016 estimate normalized to include a full year for PHI.

Proven Track Record of Improving Operational Performance

Operations	Metric	At CEG Merger (2012)			2015			2015
		BGE	PECO	ComEd	BGE	PECO	ComEd	PHI
Electric Operations	OSHA Recordable Rate							
	2.5 Beta SAIFI (Outage Frequency)							
	2.5 Beta CAIDI (Outage Duration)							
Customer Operations	Customer Satisfaction							N/A
	Service Level % of Calls Answered in <30 sec							
	Abandon Rate							
Gas Operations	Percent of Calls Responded to in <1 Hour			No Gas Operations			No Gas Operations	
	3rd Party Damages per 1000 Gas Locates							
Overall Rank	Electric Utility Panel of 24 Utilities[1]	23rd	2nd	2nd	4th	2nd	3rd	18th

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

Performance Quartiles		
	Q1	Q2
	Q3	Q4

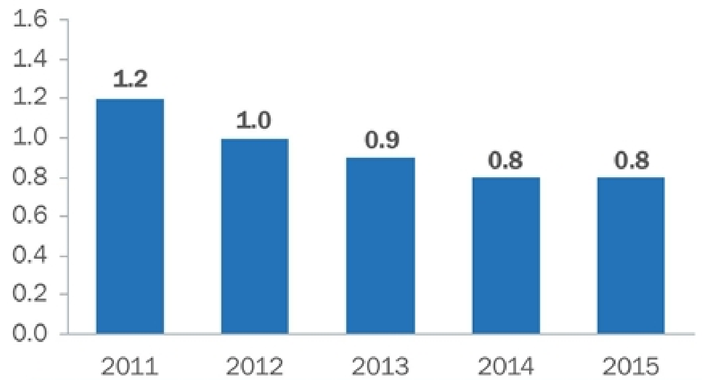
Significant opportunity for operating performance improvements at PHI

(1) Ranking based on results of five key industry performance indicators – CAIDI, SAIFI, Safety, Customer Satisfaction, and Cost per Customer

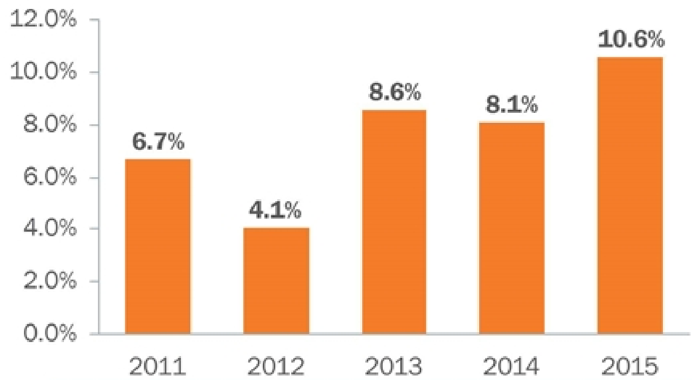
BGE: A Proven Track Record of Enhancing Utility Value

Leveraging the best practices of the Exelon Utilities platform, BGE has significantly improved operational metrics

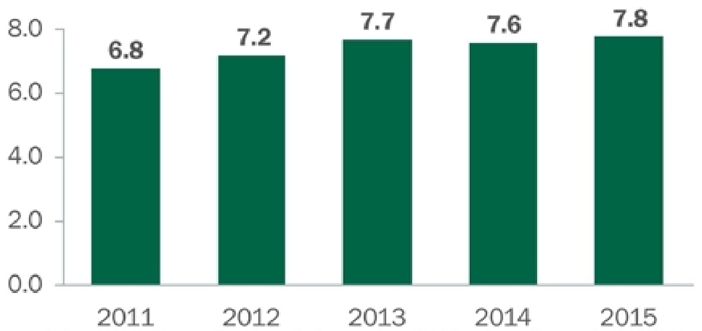
Outage Frequency (SAIFI)



Operating ROE (%)



Customer Satisfaction Index



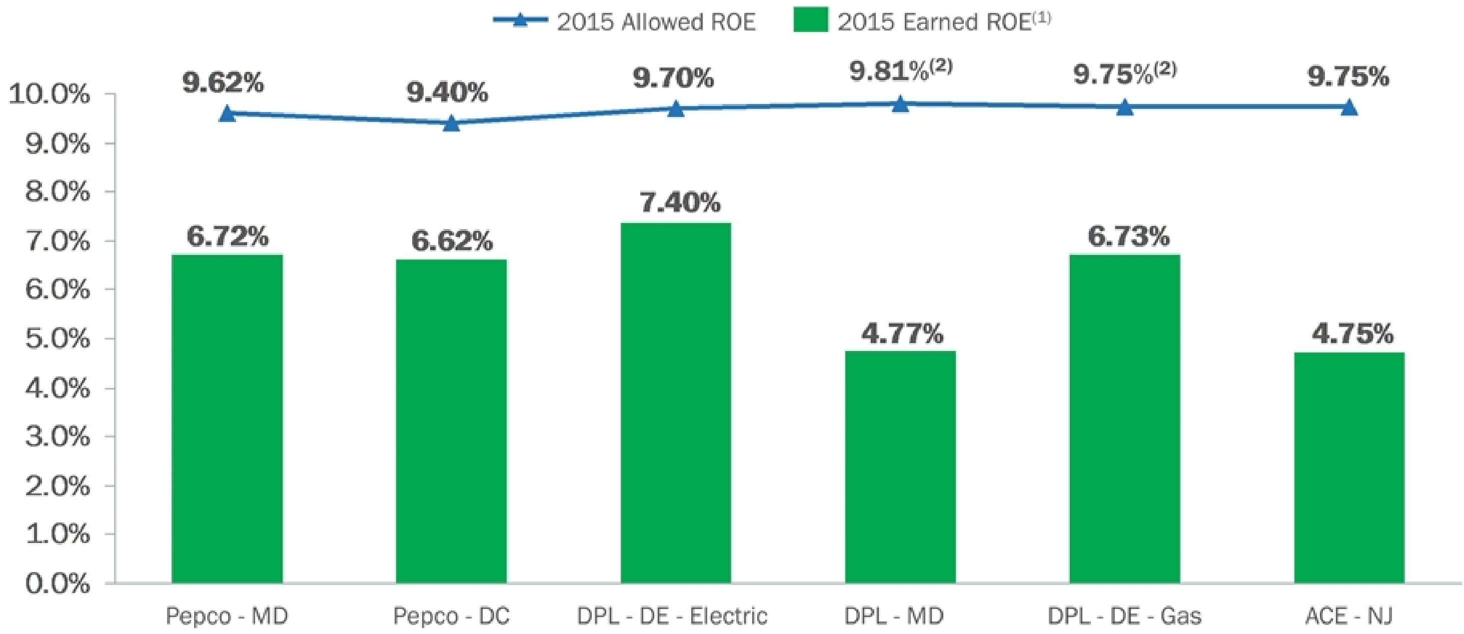
Results

- Increased reliability by 10% per year and customer satisfaction by 3% per year
- Increased ROE by more than 350 basis points from 2011 to 2015
- Continued system investments in reliability and safety requires continued rate cases for capital recovery

Note: 2012 ROE normalized by excluding one-time $112M rate credit as part of EXC-CEG merger. For a reconciliation of operating ROE, which is derived from adjusted operating earnings, which is a non-GAAP measure please refer to slide 171 in the appendix.

Exelon.

Wide Gaps in Earned vs Allowed Distribution ROEs at PHI



Impact of a 50 bps increase in Earned Distribution ROE on Operating Earnings

Pepco - MD	Pepco - DC	DPL – DE Electric	DPL - MD	DPL – DE - Gas	ACE - NJ
~$4M	~$4M	~$2M	~$2M	~$1M	~$4M

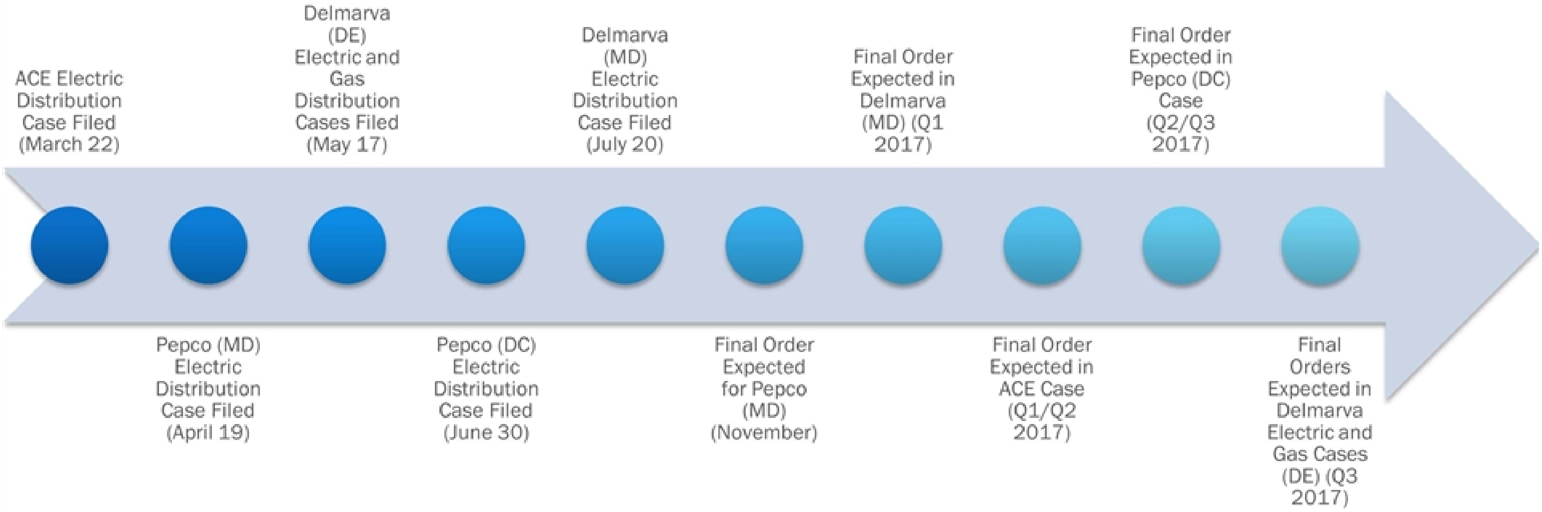
Significant opportunity for earned ROE improvement at PHI Utilities

(1) Earned ROEs represent distribution regulatory view
(2) ROE for purposes of calculating AFUDC and regulatory asset carrying costs

Near-Term PHI Regulatory Strategy

- 6 distribution rate case filings and 3 transmission formula rate filings completed, seeking $465M total revenue increase
- Rate cases include various initiatives including grid resiliency programs, economic incentive tariffs, and a Pay as You Go pre-paid metering program
- Delivery on 675 merger commitments is underway including the payment of bill credits, arrearage forgiveness, funding of energy efficiency, and workforce development
- Most favored nations discussions are continuing in New Jersey, Maryland, and Delaware

Distribution Rate Case Schedule



Note: As permitted by Delaware law, Delmarva Power implemented interim rate increases of $2.5 million on July 16, 2016 and will implement full allowable rates on December 17, 2016, subject to refund

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Long-Term PHI Regulatory Opportunity

Pursuing Existing Mechanisms	Legislative Initiatives
Pursuing alternative rate recovery mechanisms for significant capital investment programs: • PowerAhead resiliency program of $176 million included in NJ rate case • Continuation of Grid Resiliency Program of $40 million included in the MD rate cases • Working to resolve outstanding issues with the DCPLUG legislation, which involves a $1 billion underground program in DC (Pepco to invest $500 million)	**Currently Pursuing:** • **Maryland:** advance legislation to allow for surcharge recovery of reliability and resiliency costs **Under Consideration:** • **Delaware:** demand-based rates for residential customers • **New Jersey:** advocate for legislation to modernize utility regulation

We will leverage existing mechanisms and advocate for additional mechanisms where needed to cure regulatory lag issues

Exelon.

Exelon Employees Support Their Communities

5,627 Employees logged hours

129,178 volunteer hours

989 Company-endorsed volunteer events

Matching Gifts Program

$2.19 million donations made by employees + **$2.19 million** matched by the Exelon Foundation and Maryland OpCos = **$5.37 million**

Employee Giving Campaign

$6.36 million pledged by employees + **$3.18 million** matched by the company = **$9.54 million**

2015

$36,736,618 Exelon gave to charitable and community causes

Dollars for Doers

1,191 employees participated

Exelon provided more than **2,366** grants totaling **$452,600** to nonprofit organizations

540 Nonprofit boards with Exelon representation

Note: Legacy Exelon data only

ComEd

Anne Pramaggiore

President & Chief Executive Officer, ComEd

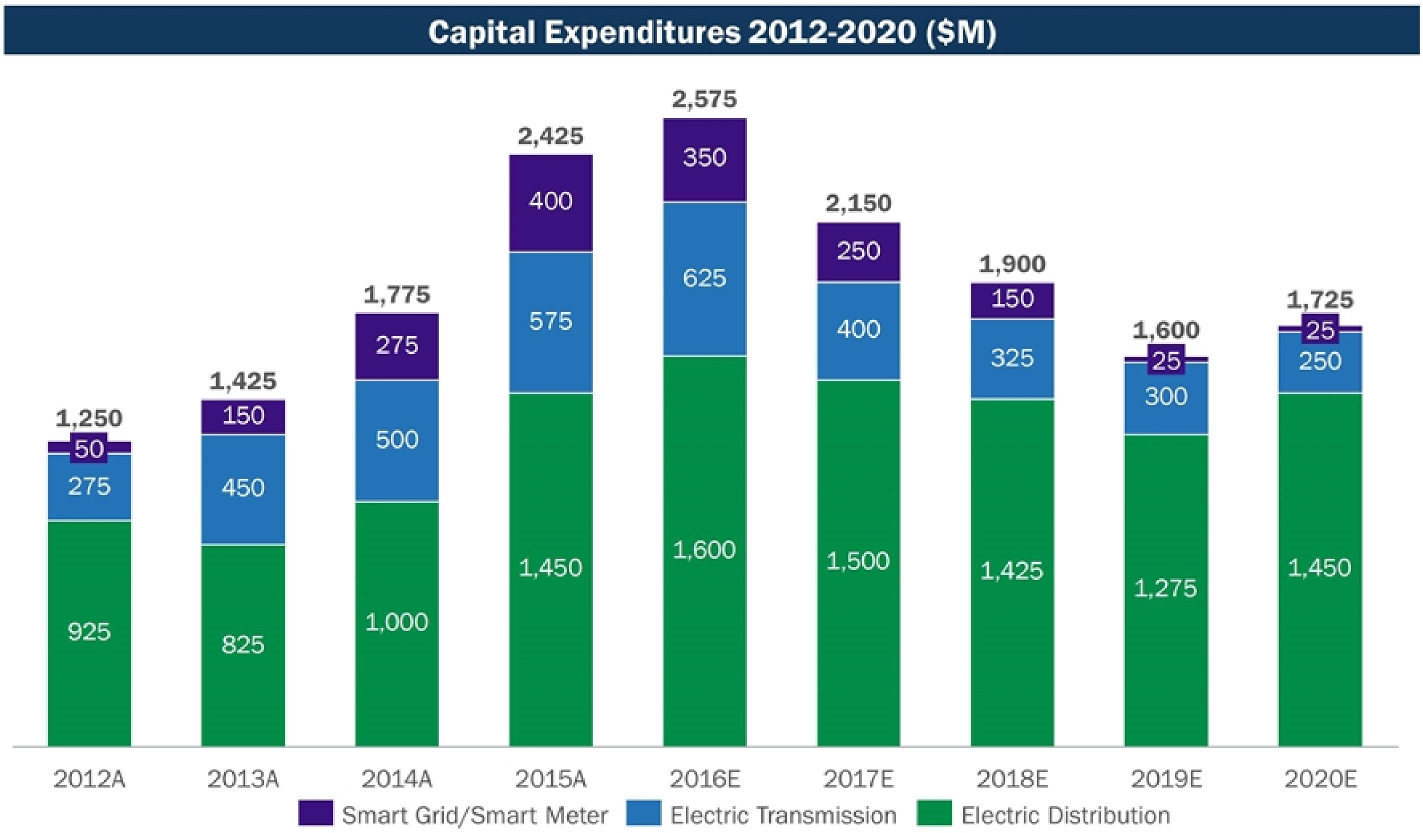
ComEd

An Exelon Company

ComEd Overview

Note: Equity Ratio for distribution only. Rate base number denotes year-end.

ComEd Capital Expenditure Forecast



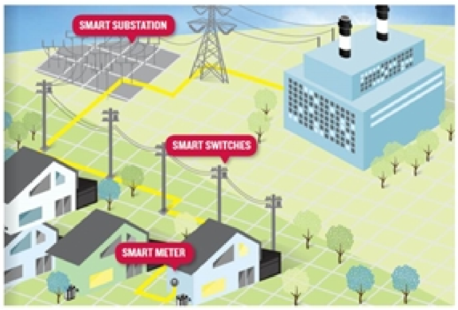
~$10B of Capital being invested from 2016-2020

Note: Numbers rounded to nearest $25M and may not add due to rounding

ComEd.
An Exelon Company

Energy Infrastructure Modernization Act (EIMA) Overview

- In October 2011, the Illinois General Assembly enacted the Energy Infrastructure Modernization Act (EIMA), setting in motion a $2.6 billion, ten-year investment by ComEd to strengthen and modernize the state's electric grid
- Investment Plan had two primary components:



- Reliability-Related Investments – $1.3B over 5 years, cable replacement, manhole refurbishment program, storm hardening program, wood poles program, and building two training centers
- Smart Grid-Related Investments – $1.3B over 10 years, distribution automation, intelligent substations, smart meters, and cyber secure communication network

Invest in Illinois

- $1.3B in infrastructure upgrades
- $1.3B in smart grid
- Create 2,000 full time jobs
- Establish Science and Energy Innovation Trust
- Establish Smart Grid Test Bed
- Contribute $50M over 5 years for customer assistance
- Increase diverse supply chain

Stabilize the Regulatory Environment

- Annual filing and reconciliation (reduces lag)
- Legislative pre approval of significant portion of investment (enhances stability)
- ROE set by formula of 30Y T-bond plus 580 bps (reduces uncertainty)
- ± 50 bps earned ROE collar (limits volatility due to weather, load and changes in customer mix)
- Regulatory asset treatment for 1 X items >$10M (stabilizes rates)

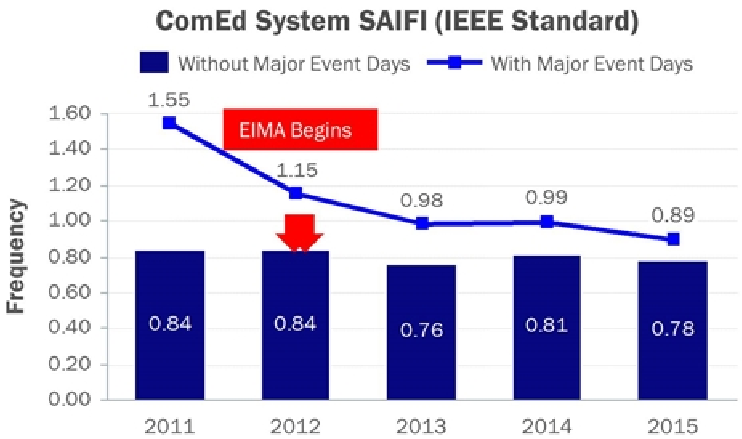
Customer Value

- ComEd must meet annual reliability and customer service improvement metrics
- Failure to meet targets results in ROE penalties
- Legislation sunsets in 2019 absent extension by the General Assembly
- Actual costs flow through for bill credits as well as increases
- Rates could not increase by more than 2.5% on average through May 2014

- **85% of program work is complete, benefitting 2.3M customers; formula rates resulting in timely recovery of costs**
- **Approved accelerated deployment plan will have 4M smart meters installed by 2018, three years in advance of the originally scheduled 2021 completion date**

EIMA Investments

Reliability Investments



- 800 storm hardening and grid resiliency engineering solutions completed
- 6,700 avoided underground cable faults and 1 million avoided customer interruptions
- 43% improvement in SAIFI compared to 2011
- Significant improvement in storm interruptions and restoration times
- 2015 best reliability on record; top decile
- Reliability complaints reduced 75% since 2011

Smart Grid Investments

- Over 2.4 million smart meters installed
- Nearly 2,500 distribution automation devices installed (program 95% complete)
- Distribution automation has avoided ~5.5M interruptions since 2012
- Smart substations benefitting 129,000 customers, including major airports
- Eliminate over 120M manual meter reads by 2018
- 2015 customer satisfaction best on record

Substation/Resiliency & Grand Prairie Gateway Investments

Substation/Resiliency Investments

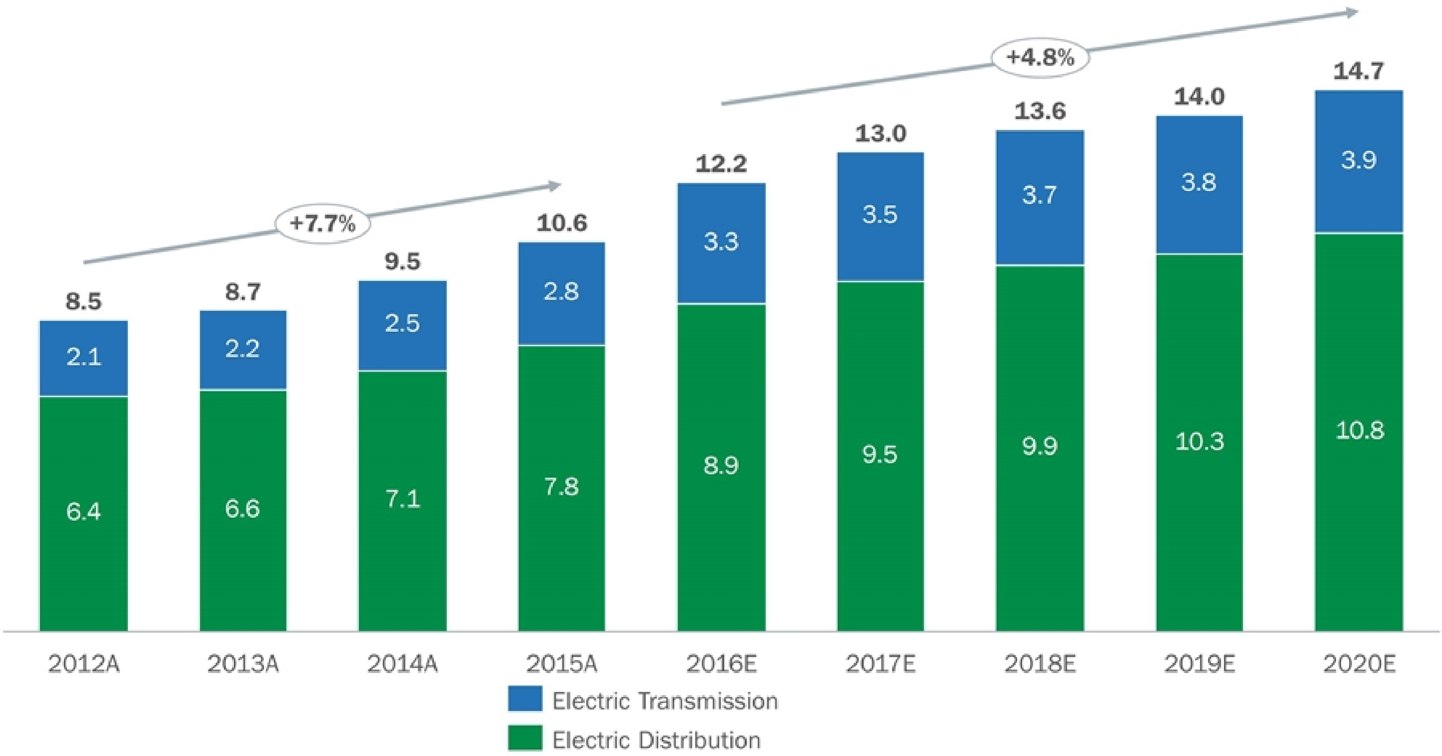
- Includes proactive replacement of substation power transformers, breakers, relays, transmission underground cable and pumping plants, rebuilding overhead lines and replacing wood structures with more resilient steel
- Projected spend of ~$825M across projects for 2015-2019
- Decreases risk of loss of major power flows and improves overall reliability, resiliency, and restoration

Grand Prairie Gateway

- 60 mile, 345 kV transmission line connecting ComEd's Byron and Wayne substations alleviating identified congestion and enhancing reliability
- $260M project with an estimated completion date of Q2 2017
- $250M of customer benefits (net of all costs) within the first 15 years of operation
- FERC-filed transmission rate of 11.5%, construction work in progress recovered and abandonment recovery secured

ComEd Rate Base Growth

Rate Base 2012-2020 ($B)

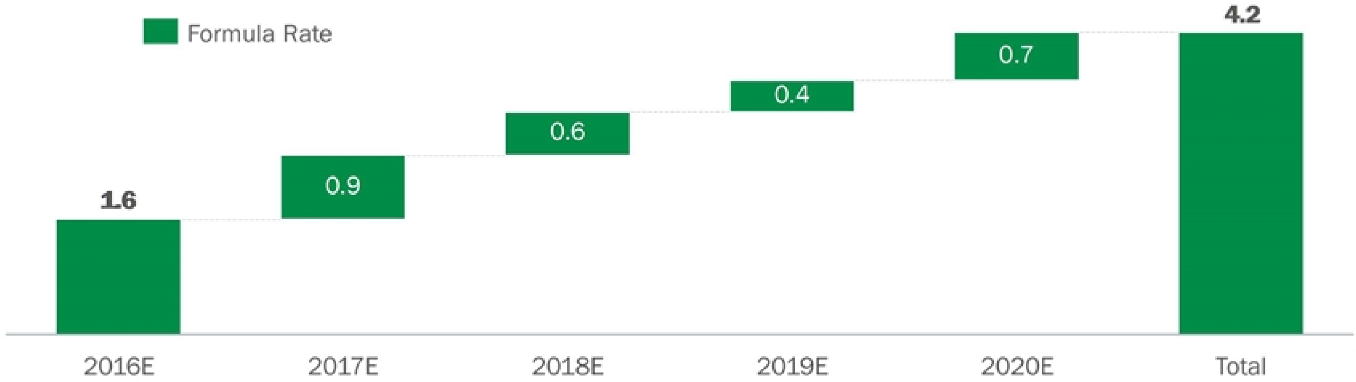


ComEd Rate Base Growing at 4.8% CAGR from 2016-2020

Note: All numbers denote year-end rate base and may not add due to rounding

Formula Rate Mechanism Covers All Rate Base Growth

Rate Base Additions Breakdown 2016-2020 ($B)(1)



Tracker/Formula Rate Recovery Mechanisms

Electric Distribution:

- Formula Rate(1)
  - 2016 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.
  - Allowed ROE equal to 30 year Treasury + 580bps

Transmission:

- FERC Formula Rate
- ROE – 11.5%

Of the approximately $4.2 billion of rate base growth at ComEd over the next 5 years, we will seek 100% recovery through existing formula mechanisms

(1) Assumes renewal of ComEd formula rate in 2019; EIMA currently sunsets in 2019

ComEd Operational Performance

Secured passage of the Energy Infrastructure Modernization Act (EIMA) in 2011, ComEd has consistently delivered continuous operational improvement

- Finished 2015 in the top decile in reliability and safety and top quartile in customer service
- Emergency Preparedness & Emergency Response Organization won the EEI Emergency Response Award for response during the June supercell thunderstorms that produced torrential rainfall along with 11 confirmed tornadoes in service territory affecting 63,000 customers

Delivered best on record performance in safety in 2015; recognized as one of America's Safest Companies in 2015 by *Environmental Health and Safety Magazine*

Recognized leader in grid modernization – *GridWise Alliance* ranked Illinois #2 for progress in implementing smart grid technologies and #1 in policy support

J.D. POWER

Achieved all-time best J.D. Power & Associates score for ComEd in the 2016 electric residential customer satisfaction index and is among the most improved utilities over the last 5 years in the industry. Also achieved its all-time best score in the J.D. Power & Associates 2016 electric business customer satisfaction index.

ComEd residential rates are lower than the national average and in the bottom half of the top 10 cities by population

Utility of the Future

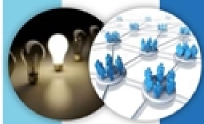
3 trends are disrupting the utility industry

1 Climate change is requiring action

- Clean energy legislation (renewables, EE)
- Increase in weather related outages

2 Technology innovation is accelerating

- Installation base of solar is growing
- Costs of solar/ storage are declining



3 Customers are increasingly digital

- Customer segments of “one”
- Pervasive connectivity

...requiring us to respond differently than we have before

- **Clean**
- **Lean**
- **Decentralized**
- **Communal**
- **With new participants**

bidgely

nest

Platform for Utility of the Future

		Producer			**Marketplace**		**Consumer**		
4 **Services & solutions marketplace**	**Enable interactions between producers and consumers** for energy and utility-enabled products and services	Lead gen / marketing & sales	Installation integration	Ongoing operations and maintenance	Marketplace curation	Transaction execution	Product / service selection	Financing solutions	Customer service
3 **Transactive commodity exchange**	Enable a liquid, efficient, and transparent **exchange for commodity transactions**	Market rules and governance	Enabling pricing transparency	Compliance and Measurement & Verification	Trading and settlements exchange				
2 **System operation and planning**	Plan, operate and maintain an **evolving, open, & reliable system at the lowest total cost** over the medium to long-term	Long-term planning	Real-time system operations						
1 **The physical asset base**	Build and maintain the distribution grid **on time, on budget, and with optimal reliability**	Execution of grid investment plan	Implementation of new grid edge infrastructure	Ongoing grid operations and maintenances					

Utility of the Future – Projects

Community of the Future

Infrastructure Convergence

Smart Streetlights

LED Streetlight + Smart Control Node + Smart Meter Mesh Network + Streetlight Management Software

AMI Water Meters

- Reduced energy costs

- Improved meter accuracy
- Manual meter reads eliminated

- Shorter billing cycles
- Reduced bad debt and theft
- Soft shut-off enabled

Utility of the Future – Projects

Superconductor

Energy Marketplace

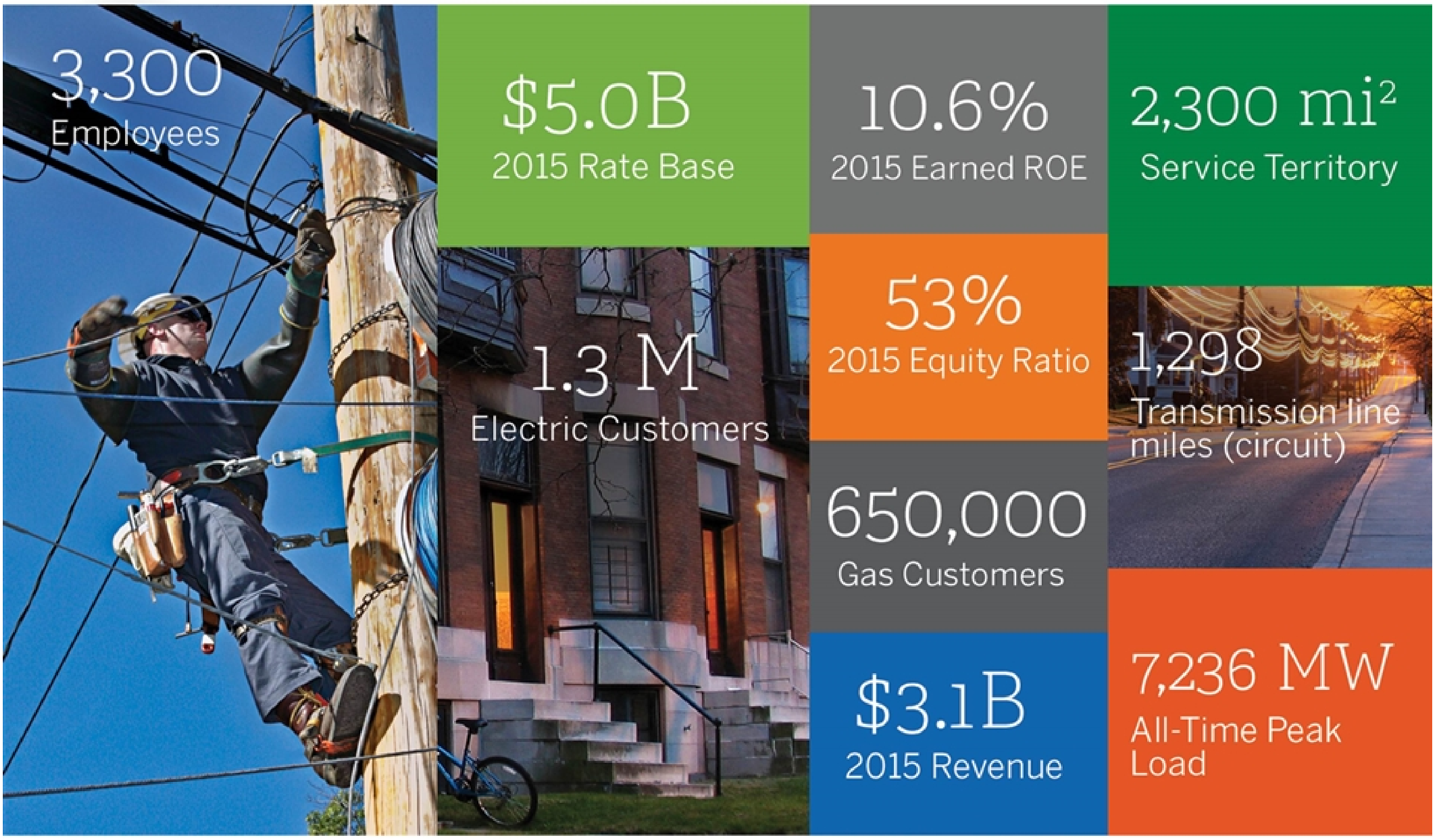
ComEd
An Exelon Company

BGE

Calvin Butler
Chief Executive Officer, BGE

BGE®
An Exelon Company

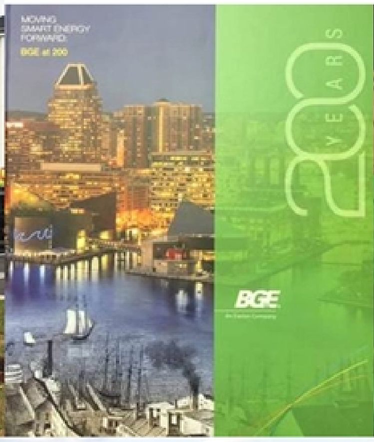
BGE Overview



Note: Rate base number denotes year-end

BGE
An Exelon Company

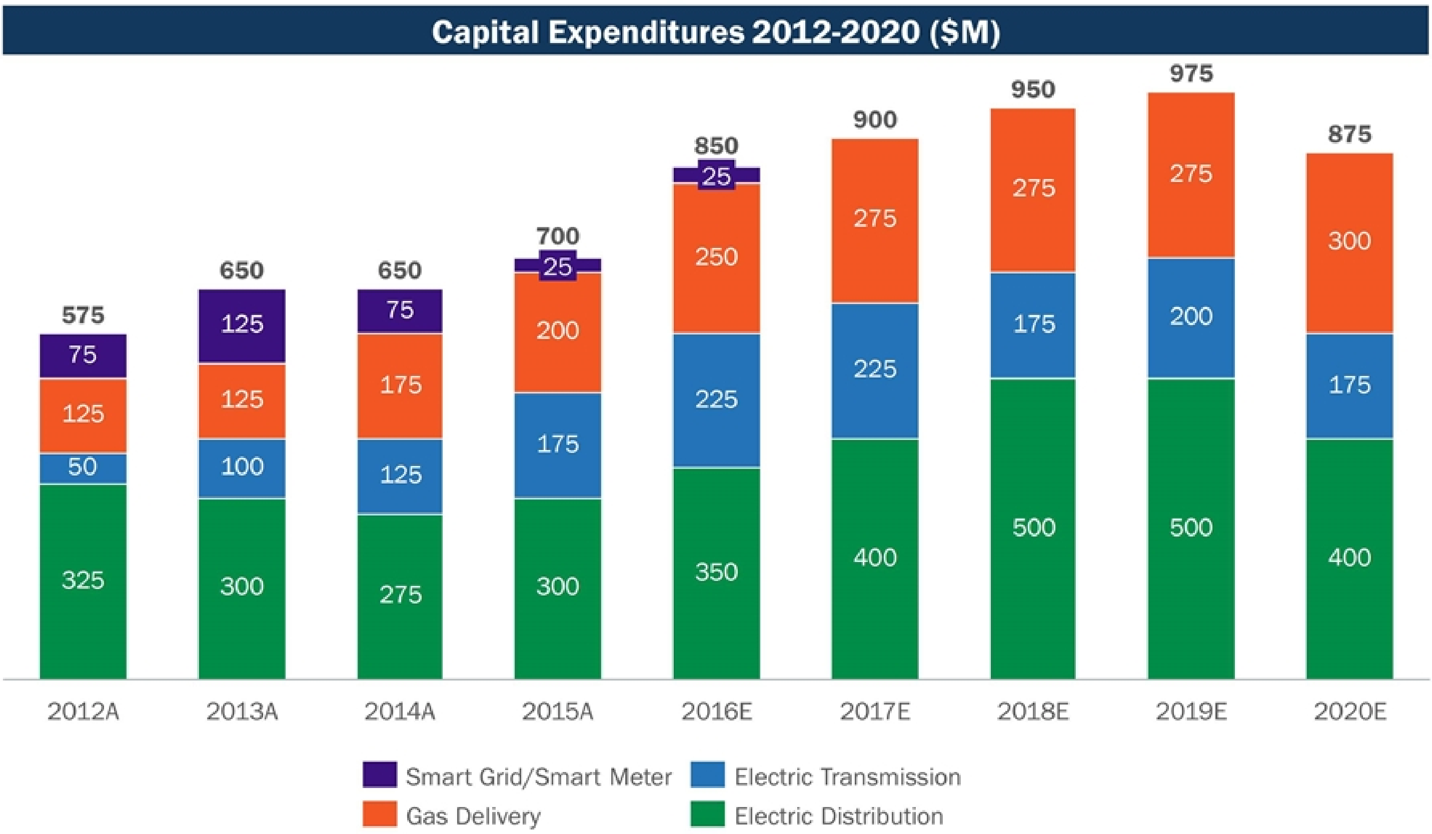
BGE celebrated its 200th anniversary as the first gas utility in the country and our continued position as an innovator and regional force




BGE 200 YEARS
moving smart energy forward
SINCE 1816

BGE Capital Expenditure Forecast



$4.5B of Capital being invested from 2016-2020

Note: Numbers rounded to nearest $25M and may not add due to rounding

Northeast Transmission System Improvement (NETSI) Project

Key Facts

- **Driver**: PJM identified thermal overloads based on NERC/PJM planning criteria during the Regional Transmission Expansion Planning (RTEP) process in 2009 and 2010 on the Graceton to Bagley 230 kV circuit and the Bagley to Raphael Road 230 kV circuit
- **Project Components**: Install a second 230 kV circuit from Bagley to Raphael Road substation (6 miles), a second 230 kV circuit from Bagley to Graceton (5 miles), a second 230 kV circuit from Graceton to Conastone (9 miles), and modifications to Raphael Road/Graceton/Bagley substations
- **Cost:** $122 million
- **Recovery Mechanism:** Fully recoverable through FERC filed transmission formula rates; transmission Return on Equity currently is 10.5% (with 50bp RTO adder)
- **Construction**: Construction began 1/1/2014 and is scheduled to be completed in spring 2017
- **In Service Date:** 6/1/2017
- **BGE System Benefits:** Improved transmission reliability, decreased transmission congestion, and improved customer reliability in portions of Harford County, Maryland

Strategic Infrastructure Development and Enhancement (STRIDE)

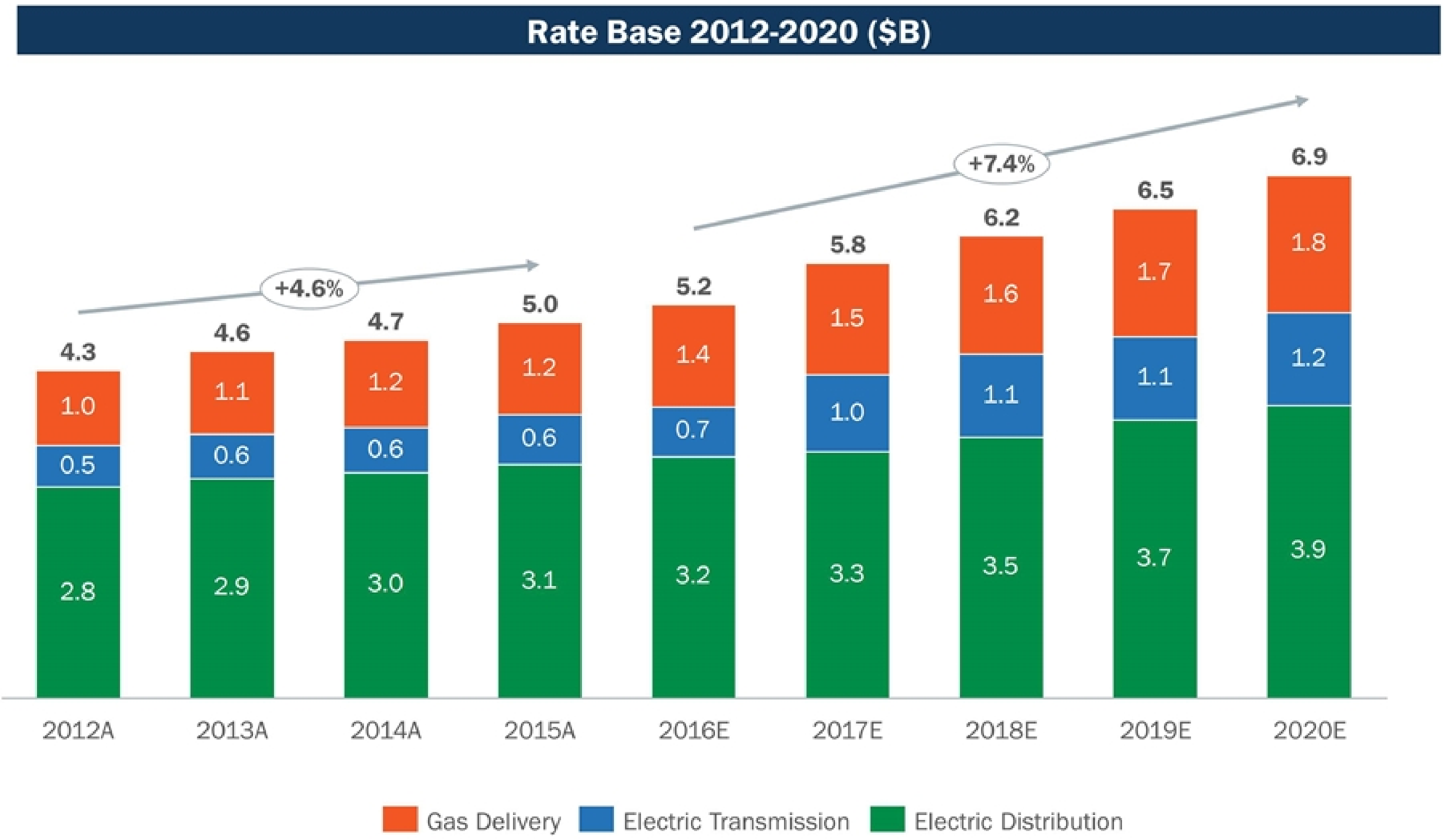
1929

2016

Key Facts

- **Project**: BGE's gas system infrastructure replacement plan is projected to be completed over a 30 year period and includes the accelerated replacement of five classes of assets: all pre-1982 plastic "Ski-Bar" service risers (13,196 risers); 42 miles of bare steel main; 1,292 miles of cast iron main; 929 miles of bare steel service pipe including 79,138 services; 277 miles of copper service pipe including 23,595 services
- **Cost:** $405 million for the initial 5 years (2014-2018)
- **Customer Benefit:** Improvement in gas system and reliability performance, including fewer leaks and additional safety devices
- **Recovery Mechanism:** Through MD PSC approved STRIDE surcharge and filed rate cases with MD PSC
- **Construction**: 2014 through 2043
- **Environmental Benefits:** 8,000 metric tons per year of methane emissions and 700 metric tons of CO2 emissions reduced over 30 years

BGE Rate Base Growth

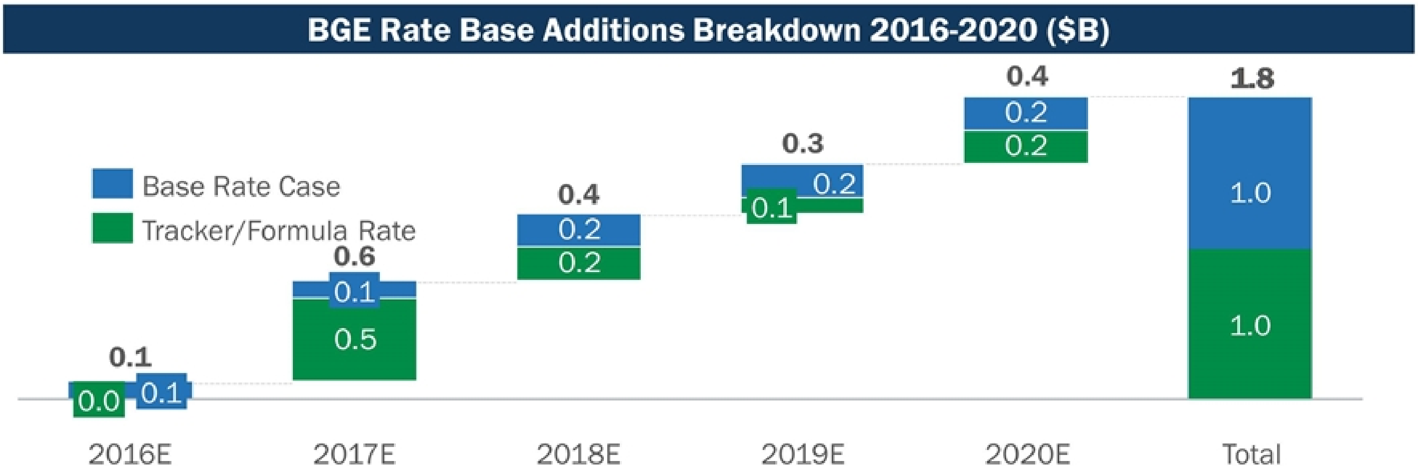


BGE Rate Base growing at 7.4% CAGR from 2016-2020

Note: All numbers denote year-end rate base and may not add due to rounding

BGE An Exelon Company

Formulaic Mechanisms Cover Half of Rate Base Growth



Base Rate Case Recovery Mechanism

Electric and Gas Distribution:

- Decoupled
- Partially forecasted test year (trued up for actuals)
- Rate implementation – Statute 7 months

Tracker/Formula Rate Recovery Mechanism

Electric and Gas Distribution:

- BGE Strategic Infrastructure Development and Enhancement (STRIDE) Tracker
- BGE Electric Reliability Investment (ERI) Tracker

Transmission:

- FERC Formula Rate
- ROE – 10.5% (10.0% base, 0.5% RTO participation adder)

Of the approximately $2 billion of rate base growth at BGE over the next 5 years, ~50% will be recovered through existing formula and tracker mechanisms

BGE
An Exelon Company

BGE Operational Performance

Since the merger in 2012, BGE has dramatically improved all aspects of operational performance

- Top decile safety performance for employee safety
- Top decile performance in gas odor response
- Top quartile in operating performance for electric reliability (frequency of interruptions), speed of restoration, customer satisfaction, and call center service level

Reduced frequency of interruptions approximately 20% since 2012 by investments such as additional automatic sectionalizing equipment on overhead lines. Reduced average restoration time by over 30% using best restoration practices developed across Exelon Utilities.

Improved BGE Call Center Service Level by over 15% through investment in improved call center technology and employee development.

J.D. POWER

Achieved all-time high score for BGE in the J.D. Power customer satisfaction index for Residential Electric in 2015. BGE has been one of the top ten performing utilities in the country from 2010 to 2015.

Improved operational performance has led to increased customer satisfaction

PECO

Craig Adams

President & Chief Executive Officer, PECO

PECO®

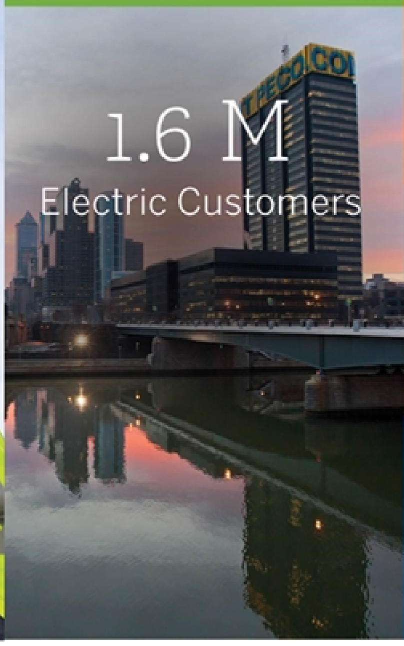
An Exelon Company

PECO Overview

$6.0B
2015 Rate Base

$3.0B
2015 Revenue

2,100 mi²
Service Territory



54%
2015 Equity Ratio

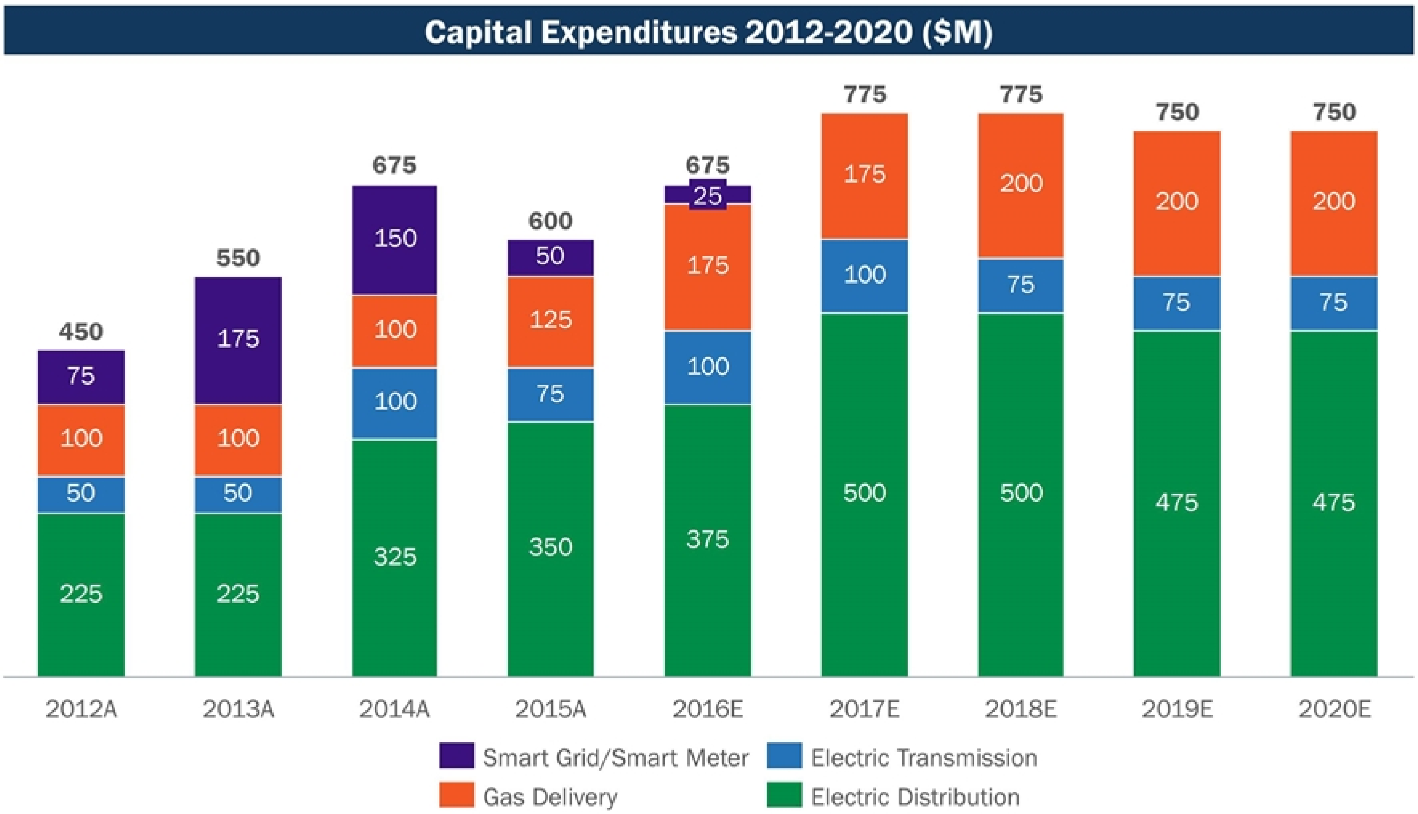
11.9%
2015 Earned ROE

500,000
Gas Customers

8,984 MW
All-Time Peak Load

Note: Rate base number denotes year-end

PECO Capital Expenditure Forecast



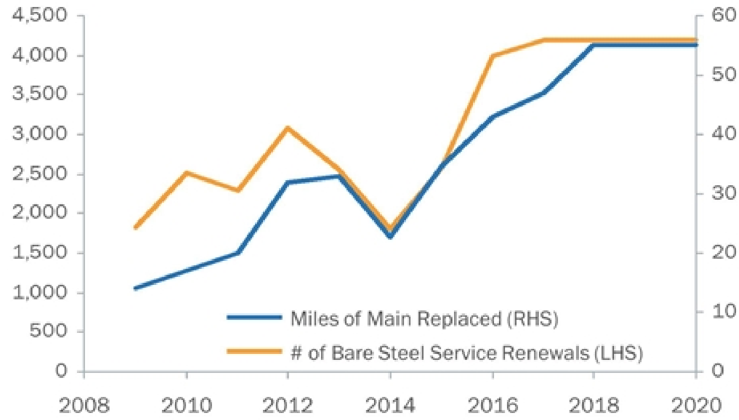
Growth in Capex driven primarily by investments in electric reliability and acceleration of gas pipeline replacement program

Note: Numbers rounded to nearest $25M and may not add due to rounding

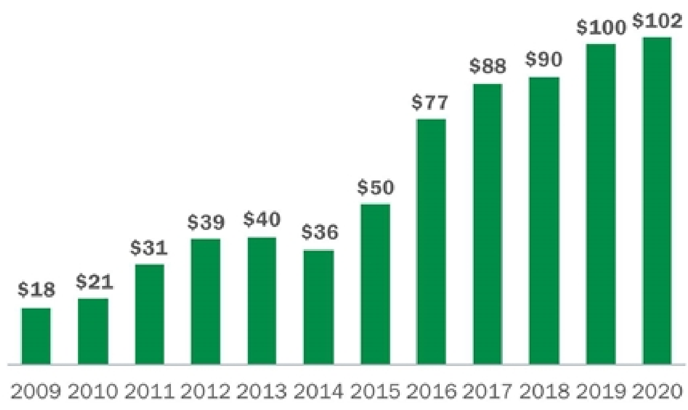
PECO An Exelon Company

Accelerated Gas Pipeline Replacement Program

Miles of Main Replaced / # Service Renewals



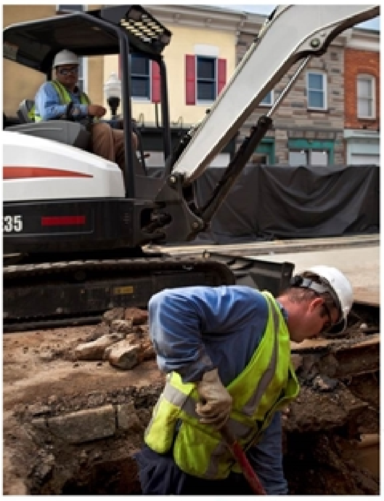
Annual Gas Replacement Capex ($M)



Key Facts

- **Scope:** Accelerating Gas Pipeline Replacement Program from 88 year program in 2010 to 20 year program
- **Cost:** Increase in annual pipeline replacement capex from $18M in 2009 to $102M in 2020. Qualifies for Tax Repairs benefits.
- **Recovery Mechanism:** Gas Long Term Infrastructure Improvement Plan (LTIIP) and Distribution System Improvement Change (DSIC) mechanisms address regulatory lag
- **Customer Benefits:** Enhances safety, is more durable and improves service reliability
- **Environmental Benefits:** 5,267 metric tons per year of methane emissions and 1,330 metric tons of CO_2 emissions reduced over 20 years

Electric System 2020 Plan



Key Facts

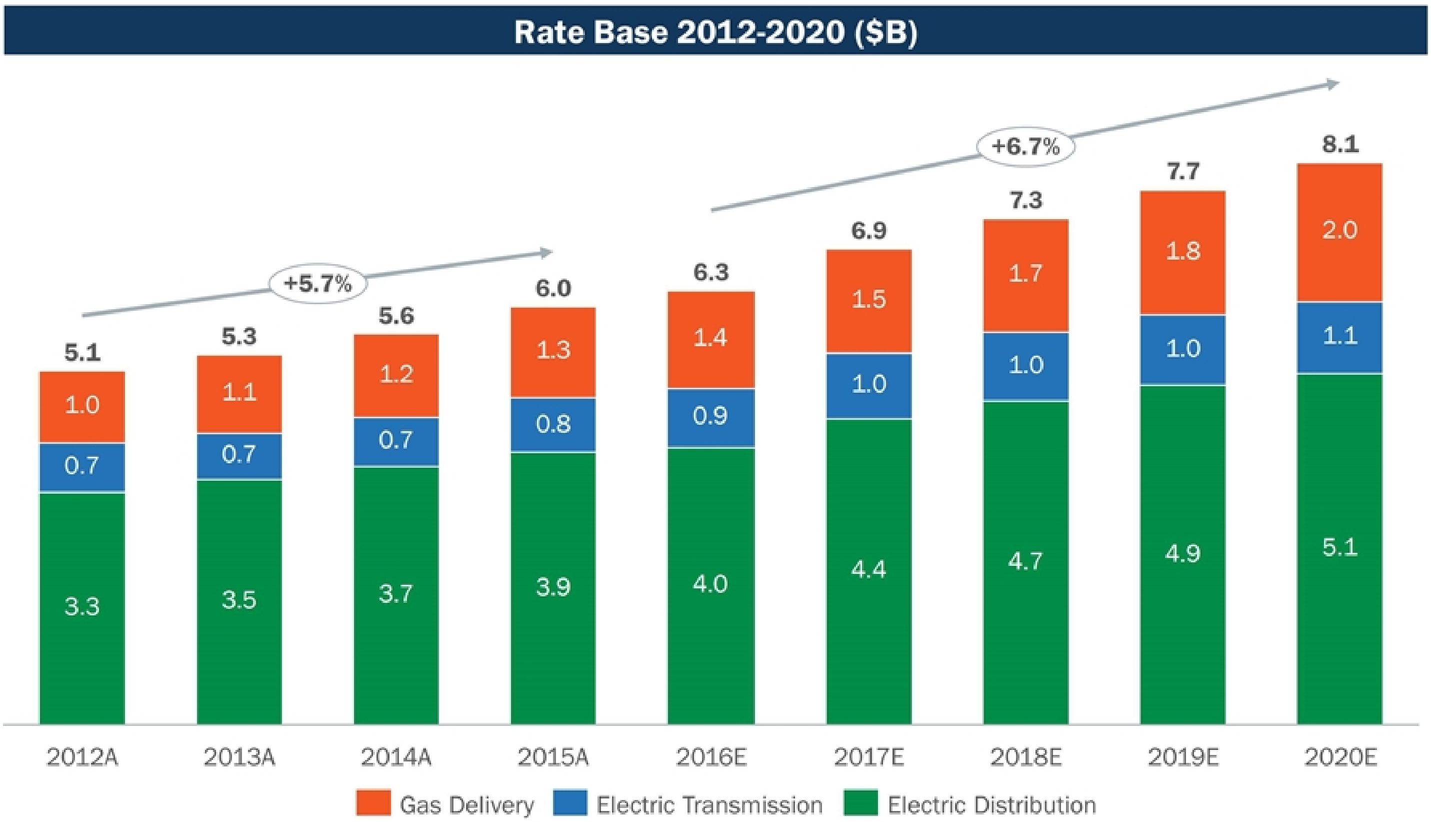
- **Scope**: 5 year LTIIP plan focused on enhancing storm hardening and addressing aging infrastructure
  - Underground Cable Replacement
  - Storm Hardening Programs
  - Substation Upgrades
- **Budgeted Cost:** $275 million
- **Regulatory Approval:** Filed LTIIP on March 27, 2015 (with Electric Distribution Rate Case), approved by PUC on October 22, 2015
- **Recovery Mechanism:** Eligible for DSIC at a ROE 9.8%
- **Customer Benefits:** Improved storm resiliency, increased service reliability

Post Substation, Marcus Hook, PA

Key Facts

- **Scope:** Construct new 220kV-13kV, 62MVA Triplex substation in Marcus Hook PA.
- **Budgeted Cost:** $43.3 million
- **Recovery Mechanism:** Base rates
- **In Service Dates:** (220kV ring bus- 5/27/16) (13kV Bus #3 & Bus #2- 9/1/16)
- **Benefits:**
  - Provides electric capacity necessary to help transform Sunoco Logistics' former refinery site in Marcus Hook into a hub for processing and shipping natural gas liquids from the Marcellus Shale region via the Mariner East pipeline
  - Additional capacity also expected to meet other load growth in Marcus Hook area
  - Reduces load on the existing 69kV system in Marcus Hook
- **Smart Substation Initiative Upgrades**
  - Fiber Optic CT's on four (4) 220kV breakers
  - Thermal camera to proactively identify equipment issues to reduce failures and outages
  - Transformer gas analysis for early warning to prevent transformer failures

PECO Rate Base Growth



PECO Rate Base growing at 6.7% CAGR from 2016-2020

Note: All numbers denote year-end rate base and may not add due to rounding

PECO
An Exelon Company

Recovery Mechanisms Evolving to be More Formulaic

Rate Base Additions Breakdown 2016-2020 ($B)

Base Rate Case Recovery Mechanism

Electric and Gas Distribution:

- Fully projected future test year
- Rate implementation – Statute 9 months

Tracker/Formula Rate Recovery Mechanism

Electric and Gas Distribution:

- Filed and receive approval of LTIIP and DSIC
- Electric DSIC ROE – 9.8%
- Gas DSIC ROE – 9.9%

Transmission:

- Assumed FERC Formula Rate beginning in 2018

Of the approximately $2 billion of rate base growth at PECO over the next 5 years, ~60% will be recovered through existing formula and tracker mechanisms

Note: Assumes PECO FERC formula rate for transmission beginning in 2018. Of the $2.0B in rate base growth, $1.15B relates to electric distribution, $0.6B relates to gas distribution and $0.3B relates to electric transmission.

PECO Operational Performance

PECO has a consistent track record of delivering strong operational performance and driving year over year improvement

- Three-year Top Decile performer in OSHA Recordable, Gas Odor Response and SAIFI
- Achieved all-time best score for PECO in 2016 J.D. Power & Associates electric residential customer satisfaction index driven by improved perception of power quality and reliability, pricing, communication, corporate citizenship, and customer service

Forbes named PECO Best Employer in the Nation in the Midsize Utility category

Four-time recipient of the ENERGY STAR Partner of the Year Award from the U.S. Environmental Protection Agency

Celebrated Leadership in Energy & Environmental Design (LEED) certification of 12 buildings, including the PECO headquarters

Market Strategies International named PECO one of the most trusted utility brands

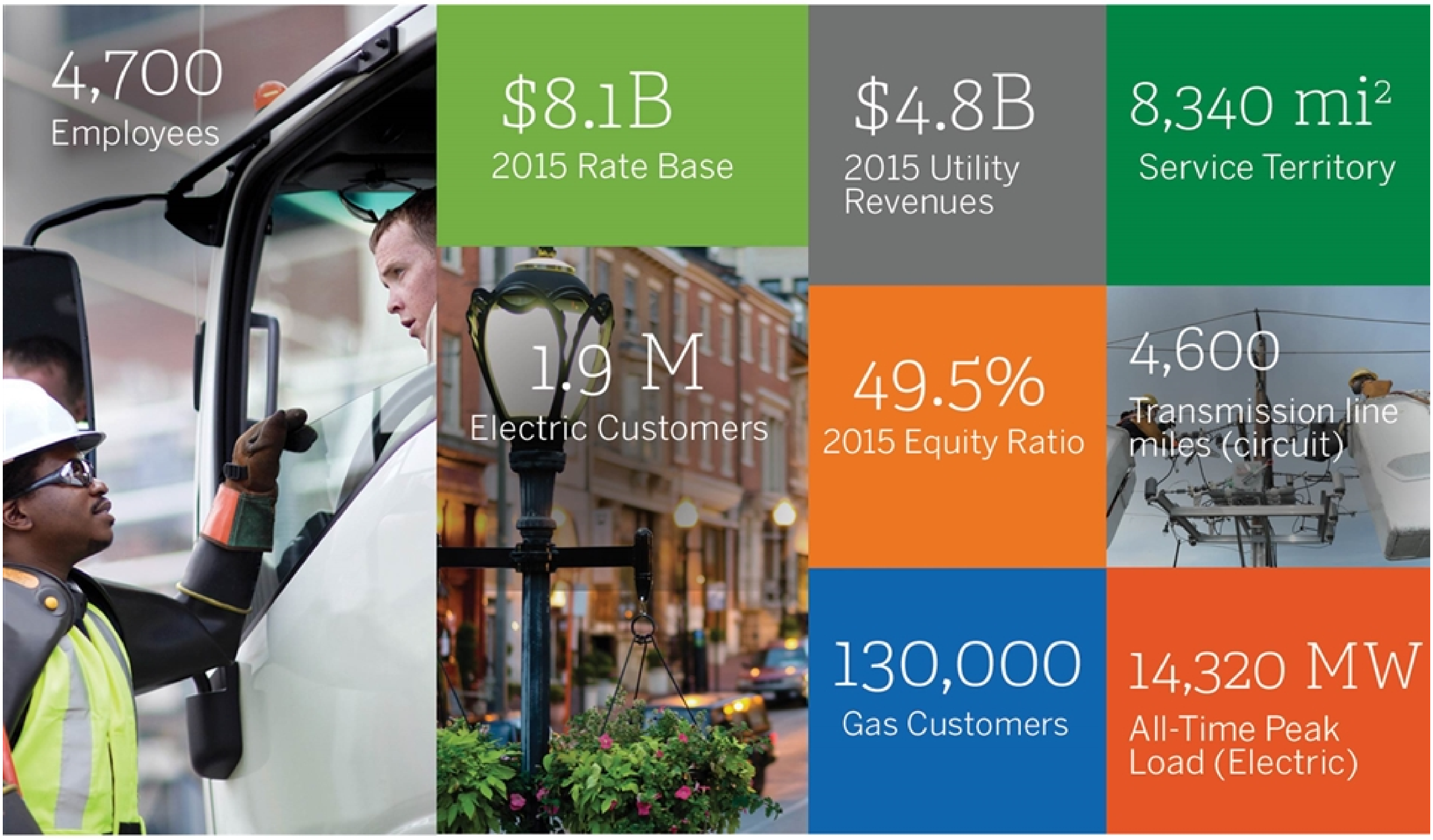
Recognized industry leader for customers, employees and the environment

Pepco Holdings

Dave Velazquez
President & Chief Executive Officer, Pepco Holdings

Pepco Holdings
An Exelon Company

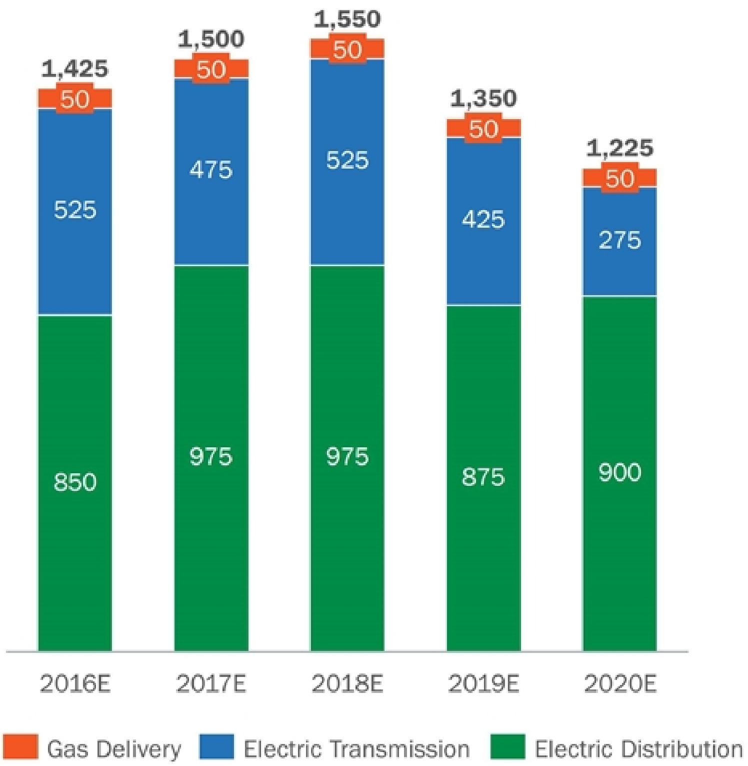
Pepco Holdings Overview



Note: All-time peak load is the sum of peak load at each PHI utility. Rate base number denotes year-end.

Pepco Holdings Capital Expenditure Forecast

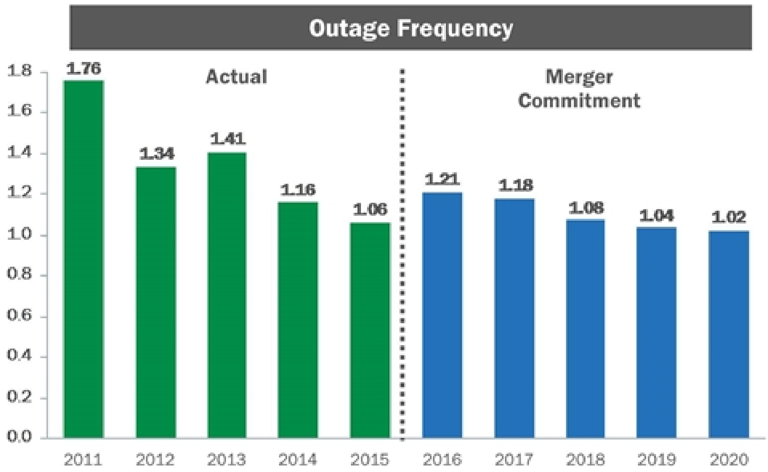
Capital Expenditures 2016-2020 ($M)

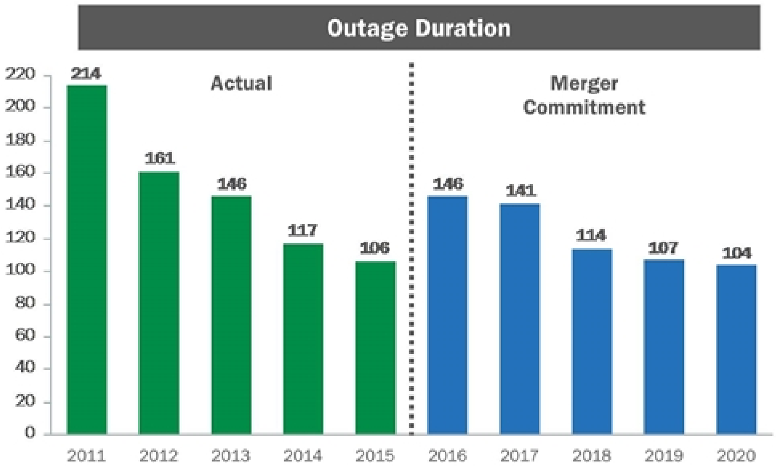


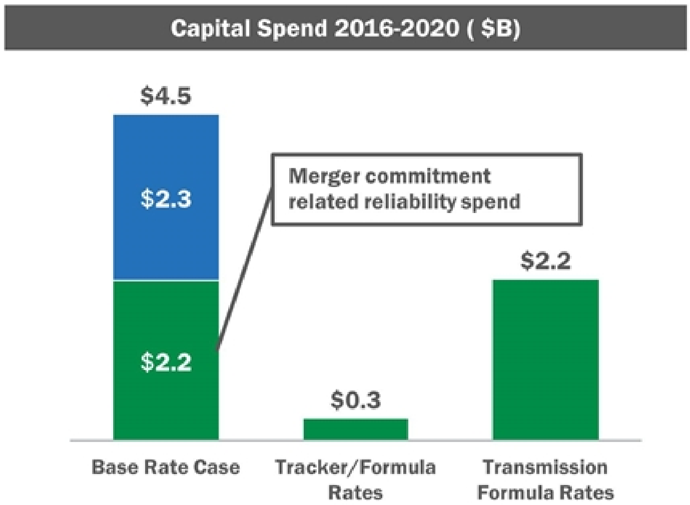
$7B of Capital being invested from 2016-2020

Note: Numbers rounded to nearest $25M and may not add due to rounding

PHI Reliability Commitments and Investment







- Merger agreements in all jurisdictions contain commitments to continue to improve reliability
- They also contain projected capital expenditures needed to meet those commitments
- Represents ~49% of total PHI distribution spending that is to be recovered through base rate cases
- Our analysis supports these investments to meet our reliability commitments

Pepco Holdings. An Exelon Company

PEPCO – Waterfront 230kV/138kV/13kV Substation

Key Facts

- **Project**: Project consists of constructing a new 230kV/138kV/13kV substation with an initial firm capacity of 140 MVA and an ultimate capacity of 350 MVA; installing 3 new underground transmission feeders 0.25 mile from Buzzard Pt Substation; and installing the initial 12 out of 72 feeders to transfer load from Buzzard Pt Substation
- **Cost:** $192 million
- **Recovery Mechanism:** Transmission portion will be recovered through Pepco's FERC regulated transmission rate. Current ROE is 10.5% (10.0% base, 0.5% RTO participation adder).
- **Construction**: In construction
- **In Service Date:** Q4 2017

DPL – Transmission Upgrades

Key Facts – Piney Grove to Wattsville

- **Project**: New 30.9 mile 138kV line from Piney Grove Sub to Wattsville Sub, built as double circuit along with Circuit 6712 (Kenney to Wattsville Substations) and with rebuild of existing 69kV Circuit 6729 (Piney Grove to Kenney Substations)
- **Cost:** $51.5 million
- **Recovery Mechanism:** Project costs will be recovered through DPL's FERC regulated transmission rate. ROE is 10.5% (10.0% base, 0.5% RTO participation adder).
- **Construction**: Design and Licensing
- **In Service Date:** Q2 2017

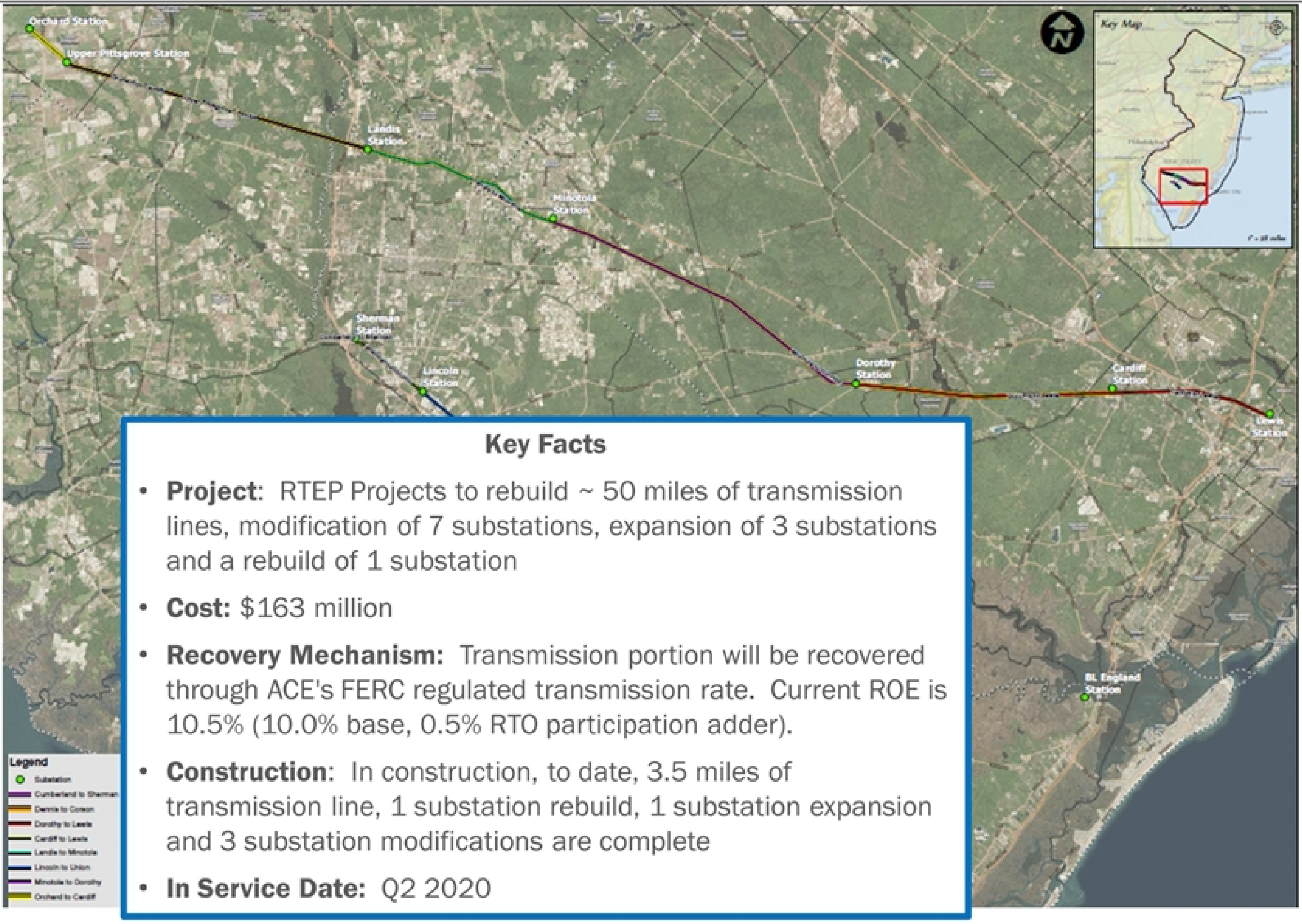
Key Facts – Cedar Creek to Milford

- **Project**: Rebuild 230kV transmission line consisting of the construction of approximately 43 miles of single circuit steel mono poles to replace failing single circuit wood H-frame structures
- **Cost:** $80.4 million
- **Recovery Mechanism:** Project costs will be recovered through DPL's FERC regulated transmission rate. ROE is 10.5% (10.0% base, 0.5% RTO participation adder).
- **Construction**: Design and Licensing
- **In Service Date:** Q4 2018

Key Facts – Church to Steele

- **Project:** Rebuild 25.5 miles of 138kV transmission line (Circuit 13701). Consists of replacing: 190 wooden H-frame structures with 189 steel poles; the existing conductor; and the existing static with new OPGW fiber. Designed and constructed to allow future 230kV energization.
- **Cost:** $35 million
- **Recovery Mechanism:** Project costs will be recovered through DPL's FERC regulated transmission rate. ROE is 10.5% (10.0% base, 0.5% RTO participation adder).
- **Construction:** In construction
- **In Service Date:** Q2 2017

ACE – Transmission Upgrades



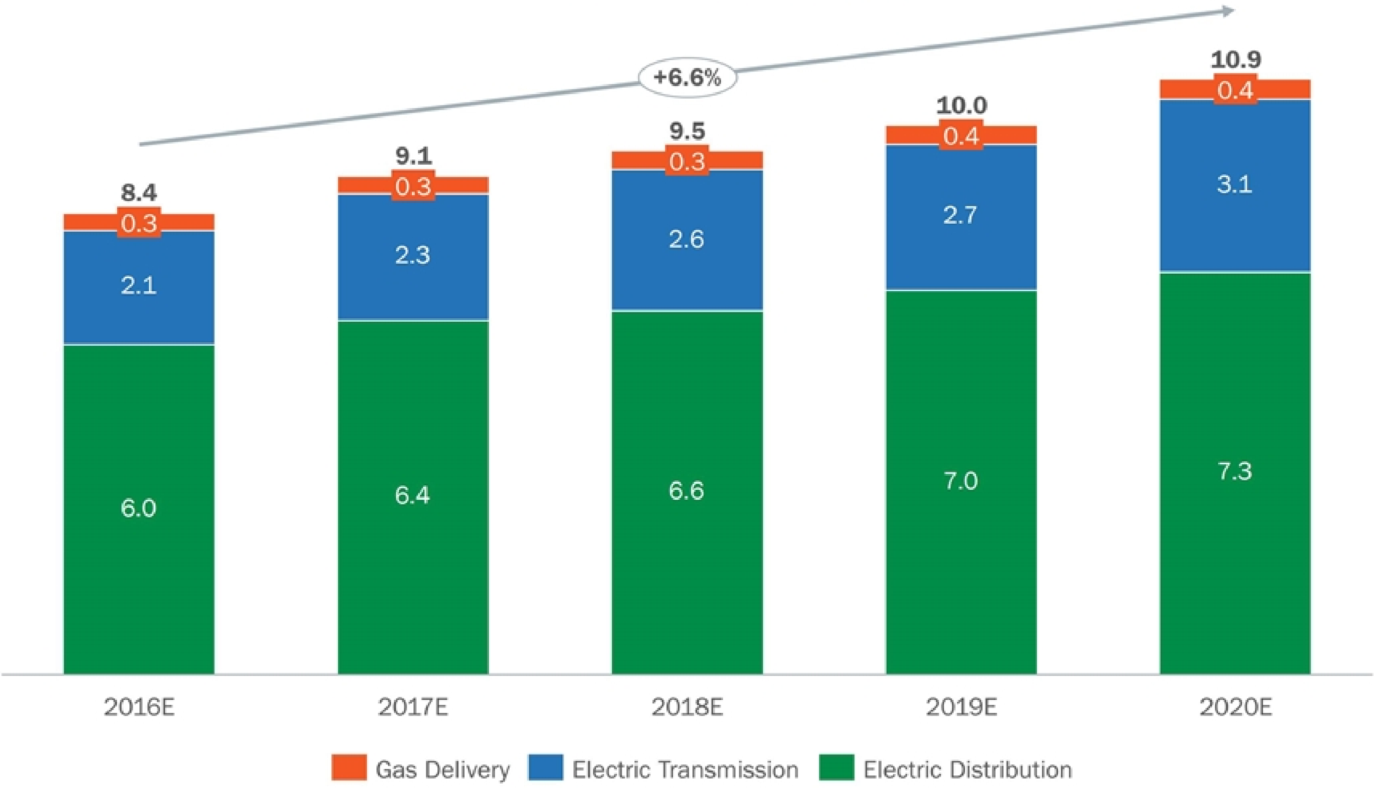
Key Facts

- **Project**: RTEP Projects to rebuild ~ 50 miles of transmission lines, modification of 7 substations, expansion of 3 substations and a rebuild of 1 substation
- **Cost:** $163 million
- **Recovery Mechanism:** Transmission portion will be recovered through ACE's FERC regulated transmission rate. Current ROE is 10.5% (10.0% base, 0.5% RTO participation adder).
- **Construction**: In construction, to date, 3.5 miles of transmission line, 1 substation rebuild, 1 substation expansion and 3 substation modifications are complete
- **In Service Date:** Q2 2020

Pepco Holdings. An Exelon Company

Pepco Holdings Rate Base Growth

Rate Base 2016-2020 ($B)



PHI Rate Base growing at 6.6% CAGR from 2016-2020

Note: All numbers denote year-end rate base and may not add due to rounding

Pepco Holdings. An Exelon Company

Rate Base Growth by Mechanism

Rate Base Additions Breakdown 2016-2020 ($B)

Base Rate Case Recovery Mechanism

Electric and Gas Distribution:

- Partially forecasted test year (trued up for actuals)
- Rate implementation:
  - DE[(1)] and MD: Statute 7 months
  - NJ: Statute 9 months[(2)]
  - DC: No Statute, target to complete cases within 9 months, however practice is closer to 12 months

Tracker/Formula Rate Recovery Mechanism

Electric and Gas Distribution:

- DC PLUG – Surcharge Recovery Mechanism (ROE – 9.4%)

Transmission:

- FERC Formula Rate
- ROE – 10.5% (10.0% base, 0.5% RTO participation adder)

Of the approximately $2.7 billion of rate base growth at PHI over the next 5 years, ~52% will be recovered through existing formula and tracker mechanisms

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of $2.5 million on July 16, 2016 and will implement full allowable rates on December 17, 2016 with interim rates subject to refund

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

Integration Update

Since merger close, we have been executing integration plans, which include standardizing processes to the Exelon management model, complying with merger commitments, and early capture of synergy value. Below are highlights:

- Completed 100% of Day 1-100 requirement; now focus is on longer-term migration activities
- On-track to achieve synergy savings
  - On-track to achieve $130M 2020 run-rate O&M savings
  - $16M in synergies achieved to date, primarily through labor savings
- On-track to achieve Supply Sourcing synergy targets
  - Merged PHI contract for all electric distribution equipment and miscellaneous items under current Exelon contract, lowering cost
  - Substantial savings from introducing additional suppliers to substation upgrade project
  - Bundled PHI needs into sourcing for all Exelon gas distribution equipment
  - Achieved savings through consolidating bill printing suppliers
- Implemented new mutual assistance work practices and successfully used them on April 4. Eight Pepco crews worked to support the PECO wind storm restoration. Common practice allows safe and more efficient sharing of resources between our companies.
- Completed 170 of the 675 merger commitments, including Customer Investment Funds and Rate Credits

Utility Appendix

Exelon Regulatory Jurisdictions

Rate Cases	Illinois	Pennsylvania	Maryland	District of Columbia	Delaware	New Jersey
Partially Forcasted Test Year	Yes	Fully Projected Future Test Year	Yes	Yes(1)	Yes	Yes
Required to update test year to actual	Yes	No	Yes	No(1)	No	Yes
Timing for Rate Implementation	Statute - January 1 of the year following the filling	Statute - 9 Months to complete filing	Statute - 7 months; rates automatically go into effect subject to refund	No statute; target to complete cases within 9-12 months of filing	Statute - 7 months; company files request to implement rates, subject to refund	Statute - 9 months; company files request to implement rates, subject to refund(2)
Time Restrictions on Initiating Subsequent Rate Filings	Yes - Annually	No, not unless agreed upon	No	No	No	No
Staff Party to Case	Yes	Yes	Yes	No	Yes	Yes
Commissions						
Full Time / Part Time	Full-Time	Full-Time	Full-Time	Full-Time	Part-Time	Full-Time
Appointed / Elected	Appointed	Appointed	Appointed	Appointed	Appointed	Appointed
Length of Term	5 years	5 years	5 years	4 years	5 years	6 years
Commissioners(3)						
Name (Term Expiration)	**Brien Sheahan (2020)** Ann McCabe (2017) Miguel del Valle (2018) Sherina Maye Edwards (2018) John Rosales (2019)	**Gladys M. Brown (2018)** Andrew Place (2020) John F. Coleman (2017) Robert F. Powelson (2019) David Sweet (2021)	**Kevin Hughes (2018)** Harold Williams (2017) Jeannette M. Mills (2019) Michael T. Richard (2020) Anthony O'Donnell (2021)	**Betty Ann Kane (2018)** Joanne Doddy Fort (2016)(4) Willie L. Phillips (2018)	**Dallas Winslow (2020)** Joann Conaway (2020) Harold Gray (2019) Kim Drexler (2020) Manubhai Karia (2020)	**Richard S. Mroz (2020)** Diane Solomon (2018) Joseph L. Fiordaliso (2019) Mary-Anna Holden (2017) Upendra J. Chivukula (2020)

(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
(4) Term expired on June 30, 2016; hold over

Exelon Utilities Distribution Rate Case Schedule

	Q1 2016	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017
ComEd Electric Distribution Formula Rate		IL Formula Rate Case Filed April 13		Final Order Expected December			
ACE Electric Distribution Rates	NJ Rate Case Filed March 22				Final Order Expected Q1/Q2		
Pepco Electric Distribution Rates - MD		MD Rate Case Filed April 19		Final Order Expected November			
Pepco Electric Distribution Rates - DC		DC Rate Case Filed June 30				Final Order Expected Q2/Q3	
Delmarva Electric and Gas Distribution Rates - DE		DE Rate Case Filed May 17					Final Order Expected
Delmarva Electric Distribution Rates - MD			MD Rate Case Filed July 20		Final Order Expected		

BGE Rate Case

	Electric	Gas
Docket #	**9406**	
Test Year	**December 2014 – November 2015**	
Common Equity Ratio	**51.9%**	
Authorized Returns	**ROE: 9.75%; ROR: 7.28%**	**ROE: 9.65%; ROR: 7.23%**
Requested Rate of Return	**7.95%**	**7.90%**
Rate Base	**$2.9B**	**$1.2B**
Revenue Requirement Increase	**$41.7M**	**$47.8M**
Distribution Increase as % of overall bill for residential customer	**2%**	**6%**
Notes	• 11/06/15 BGE filed application with the MDPSC seeking increases in electric & gas distribution base rates; request was subsequently revised in Q1 to reflect impact of additional actual data • 6/03/16 PSC Order received • 6/04/16 New rates in effect • Order concluded that BGE's AMI system overall is cost beneficial to customers, however the PSC made decisions in the rate case related to smart meters that made BGE take a $84M write-off (resulting in a Q2 2016 impairment charge). The PSC also disallowed $30M of added costs associated with BGE's usage of the Baltimore City conduit system. • 6/30/16 filed request for rate case re-hearing asking that the PSC reconsider decisions resulting in $84M write-off and the disallowance of $30M of added Baltimore City conduit system; Request would result in no additional increase to customer rates. The PSC requested and received comments on the rehearing request from the other parties. • 7/29/2016 PSC issued order on rehearing granting further increase to electric revenue requirement of $2.4M and gas revenue requirement of $0.1M and to defer post test year smart grid costs in a new regulatory asset so it may seek recovery of the costs in a future base rate proceeding. The rehearing decision will result in a reversal of the write-off of $32.4M. The PSC did not revise its decision on the Baltimore City conduit fee increase.	

ACE Electric Distribution Rate Case

Docket #	ER16030252
Test Year	2015 Calendar Year
Test Period	12 months actual
Requested Common Equity Ratio	49.5%
Requested Rate of Return	ROE: 10.60%; ROR: 8.06%
Proposed Rate Base (Adjusted)	$1.3B
Requested Revenue Requirement Increase (Updated on May 10, 2016)	$79.4M (excluding Sales & Use Tax)
Residential Total Bill % Increase	6.5%
Notes	• 3/22/16 ACE filed application with the NJBPU seeking increase in electric distribution base rates • 12 month forward looking reliability and other plant additions from January 2016 through December 2016 ($15.9M of Revenue Requirement based on a 10.60% ROE) included in revenue requirement request • 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) Procedural Schedule: • Evidentiary Hearings: 9/29/16 – 10/13/16 • Initial Briefs: 11/1/16 • Commission Order Expected: 3/22/17

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.

Docket #	16-0259
Filing Year	**2015 Calendar Year Actual Costs and 2016 Projected Net Plant Additions** 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.
Reconciliation Year	**Reconciles Revenue Requirement reflected in rates during 2015 to 2015 Actual Costs Incurred.** Revenue requirement for 2015 is based on docket 14-0312 (2013 actual costs and 2014 projected net plant additions) approved in December 2014.
Common Equity Ratio	**~46%** for both the filing and reconciliation year
ROE	**8.64%** for the filing year (2015 30-yr Treasury Yield of 2.84% + 580 basis point risk premium) and **8.59%** 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
Requested Rate of Return	**~7%** for both the filing and reconciliation years
Rate Base	**$8,830 million–** 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)
Revenue Requirement Increase	**$138M increase** ($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.
Timeline	• 04/13/16 Filing Date • 240 Day Proceeding

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.

Pepco MD Electric Distribution Rate Case

Case No.	9418
Test Year	2015 Calendar Year
Test Period	12 months actual
Requested Common Equity Ratio	49.6%
Requested Rate of Return	ROE: 10.60%; ROR: 8.01%
Proposed Rate Base (Adjusted)	$1.8B
Requested Revenue Requirement Increase (Updated on May 27, 2016)	$126.6M
Residential Total Bill % Increase	10.3%
Notes	• 4/19/16 Pepco MD filed application with the MDPSC seeking increase in electric distribution base rates • Size of ask is driven by 2 years of capital investment, recovery of AMI investments and new depreciation rates • 12 month forward looking reliability and other plant additions from January 2016 through December 2016 ($20.0M of Revenue Requirement based on a 10.60% ROE) included in revenue requirement request • Extension of the Grid Resiliency Program to fund accelerated investments in grid resiliency, incremental to the capital plan (not included in revenue requirement request) • Capital $31.6 million (Feeder Work $24.0 million and Reclosing Devices $7.6 million) in 2017-2018 Procedural Schedule: • Evidentiary Hearings: 9/13/16 – 9/23/16 • Final Reply Briefs: 10/26/16 • Commission Order Expected: 11/15/16 • New rates are in effect shortly after the final order

DPL DE (Electric) Distribution Rate Case

Docket #	16-0649
Test Year	2015 Calendar Year
Test Period	12 months actual
Requested Common Equity Ratio	49.4%
Requested Rate of Return	ROE: 10.60%; ROR: 7.19%
Proposed Rate Base (Adjusted)	$846M
Requested Revenue Requirement Increase	$62.8M(1)
Residential Total Bill % Increase	7.25%
Notes	• Procedural Schedule: Evidentiary Hearings 3/7/17 – 3/9/17 • 5/17/16 DPL DE filed application with the DPSC seeking increase in electric distribution base rates • 18 month forward looking reliability and other plant additions from January 2016 through June 2017 ($8.4M of Revenue Requirement based on 10.60% ROE) included in revenue requirement request • Includes the Pay as You Go Program, a proposed pilot program that would be cooperatively designed to use the capability of the AMI meters to offer a voluntary pre-paid metering option for customers • Q3 2017 - PSC order expected

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of $2.5 million on July 16, 2016 and will implement full allowable rates on December 17, 2016, subject to refund

DPL DE (Gas) Distribution Rate Case

Docket #	16-0650
Test Year	2015 Calendar Year
Test Period	12 months actual
Requested Common Equity Ratio	49.4%
Requested Rate of Return	ROE: 10.60%; ROR: 7.19%
Proposed Rate Base (Adjusted)	$362M
Requested Revenue Requirement Increase	$21.5M(1)
Residential Total Bill % Increase	10.40%
Notes	• 5/17/16 DPL DE filed application with the DPSC seeking increase in gas distribution base rates • 18 month forward looking reliability and other plant additions from January 2016 through June 2017 ($3.4M of Revenue Requirement based on 10.60% ROE) included in revenue requirement request • Q3 2017 - PSC order expected

(1) As permitted by Delaware law, Delmarva Power implemented interim rate increases of $2.5 million on July 16, 2016 and will implement full allowable rates on December 17, 2016, subject to refund

Pepco DC Distribution Rate Case

Formal Case No.	1139
Test Year	April 1, 2015 – March 31, 2016
Test Period	12 months actual
Requested Common Equity Ratio	49.14%
Requested Rate of Return	ROE: 10.60%; ROR: 8.00%
Proposed Rate Base (Adjusted)	$1.8B
Requested Revenue Requirement Increase	$85.5M
Residential Total Bill % Increase	5.25%(1)
Notes	• 6/30/16 Pepco DC filed application with the DCPSC seeking increase in electric distribution base rates • Size of ask is driven by 3 years of capital investments • 18 month forward looking reliability and other plant additions from April 2016 through September 2017 ($30.2M of Revenue Requirement based on 10.60% ROE) included in revenue requirement request • The Merger Order provides for a Customer Base Rate Credit (CBRC) in the amount of $25.6M, which can be used to offset rate increases approved by the DCPSC; the parties will be provided an opportunity to propose how the CRBC and Incremental Offset be allocated and over what period of time • The DCPSC will ultimately decide how to allocate the CBRC • Q2/Q3 2017 - PSC order expected

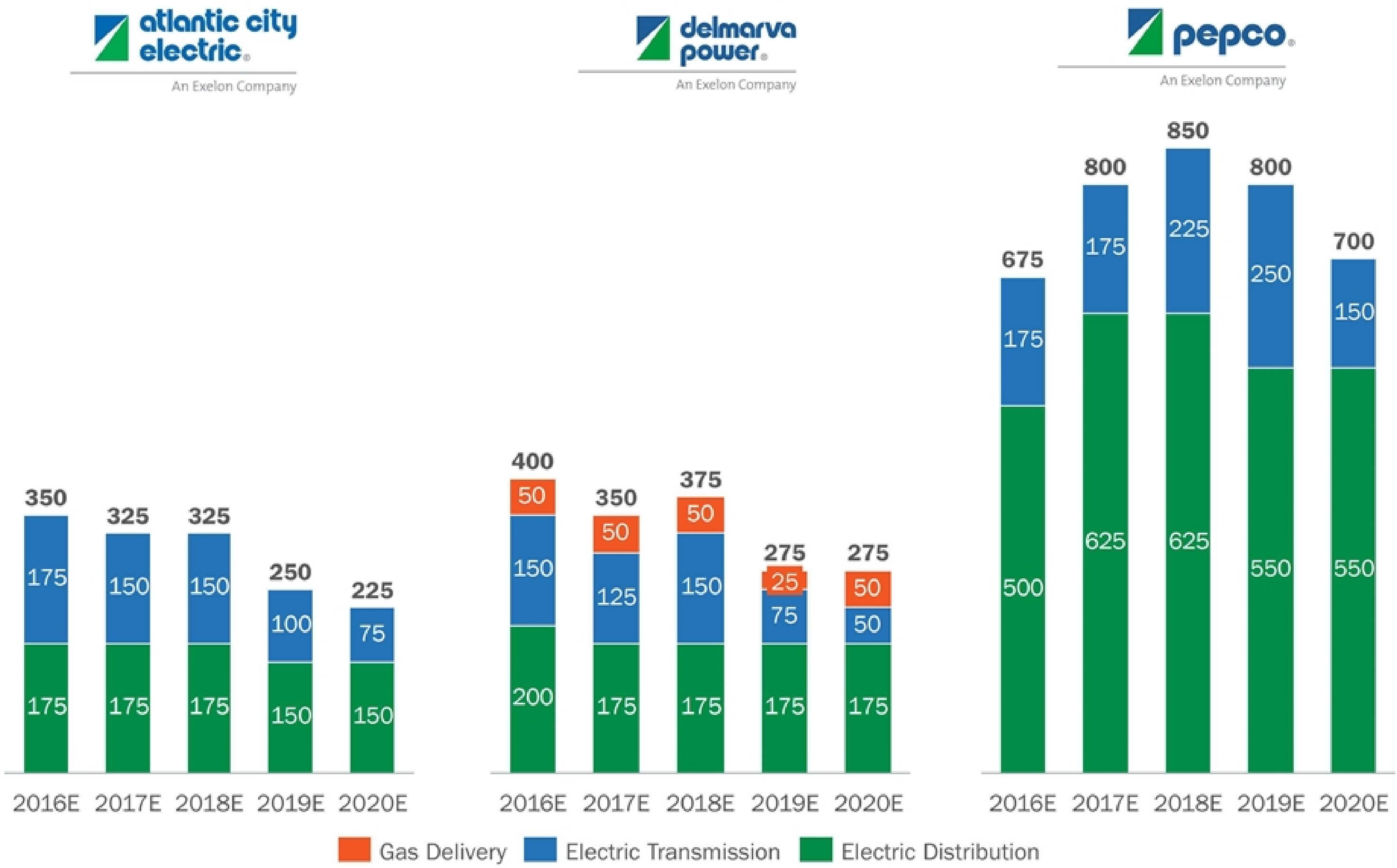
(1) As proposed by the Company, the full allocation of the CBRC to Residential and MMA customers, along with the proposal for a $1M Incremental Offset for residential customers, will ensure that residential customers do not receive an increase on the distribution portion of their bill until approximately January 2019 (February 2019 for MMA customers). Upon expiration of the CBRC and Incremental Offset proposed by the Company, this rate increase would translate to a 5.25% total bill increase for a residential customer.

Pepco Holdings. An Exelon Company

DPL MD Distribution Rate Case

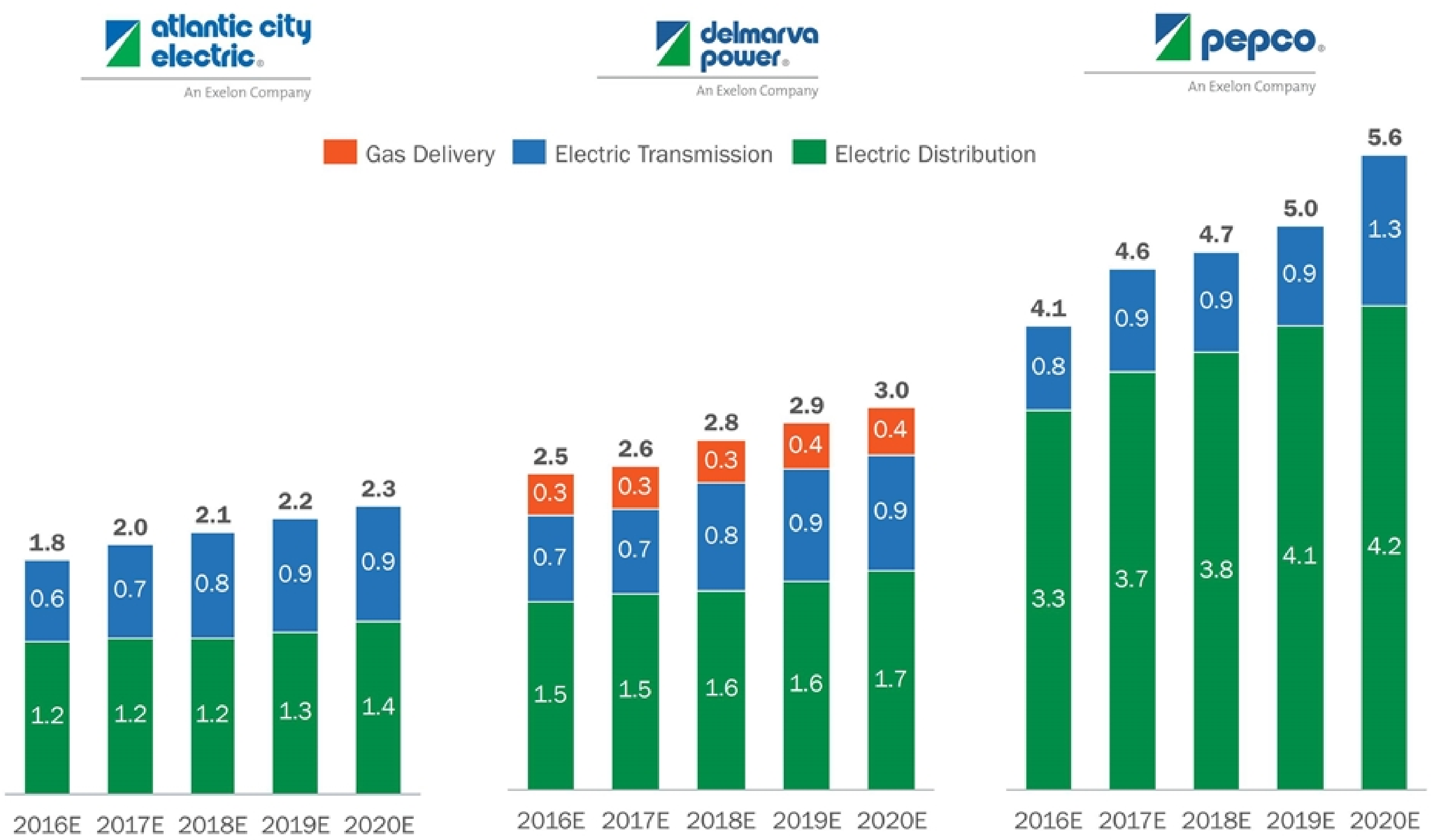
Case No.	9424
Test Year	April 1, 2015 – March 31, 2016
Test Period	12 months actual
Requested Common Equity Ratio	49.1%
Requested Rate of Return	ROE: 10.60%; ROR: 7.24%
Proposed Rate Base	$744M
Requested Revenue Requirement Increase	$66.2M
Residential Total Bill % Increase	14.5%
Notes	• 7/20/16 DPL MD filed application with the MDPSC seeking increase in electric distribution base rates • Size of ask is driven by 3 years of capital investment, recovery of AMI investments and new depreciation rates • Extension of the Grid Resiliency Program to fund accelerated investments in grid resiliency, incremental to the capital plan (not included in revenue requirement request) Capital $9.2 million (Feeder Work $4.2 million and Reclosing Devices $5.0 million) in 2017-2018 • 12 month forward looking reliability and other plant additions from April 2016 through March 2017 ($8.2M of Revenue Requirement based on 10.60% ROE) included in revenue requirement request • 7 Month Proceeding • Q1 2017 - PSC order expected • New rates are in effect shortly after the final order

Pepco Holdings Capital Expenditures



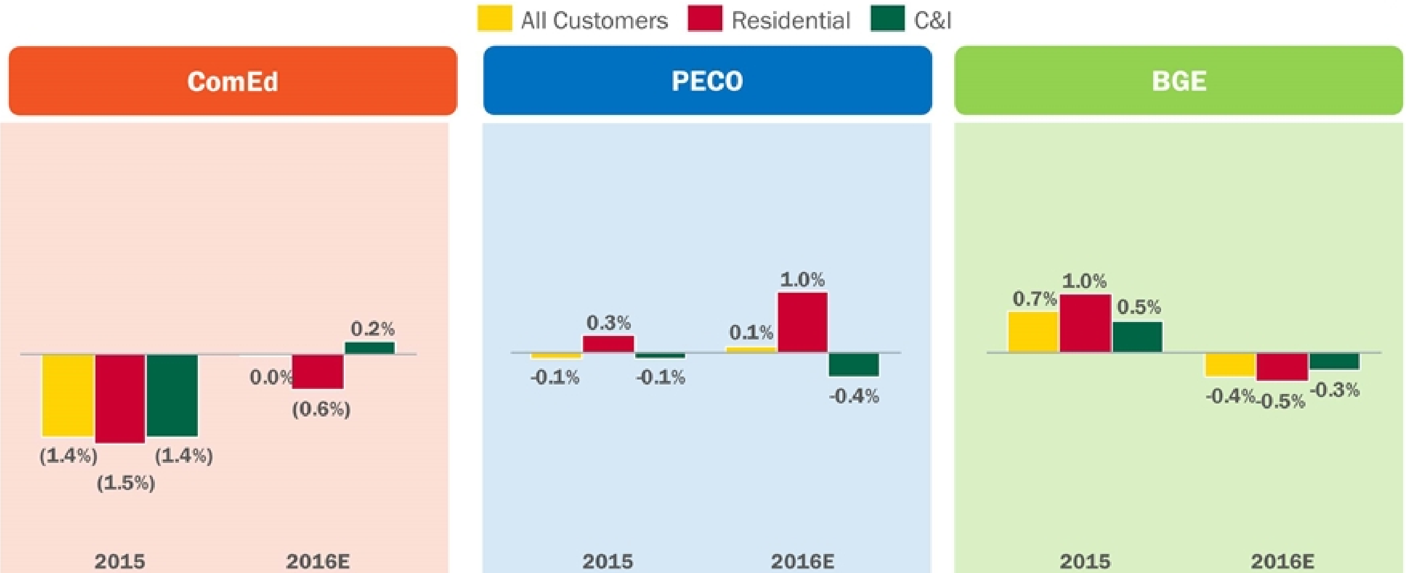
Note: Numbers rounded to nearest $25M and may not add due to rounding

Pepco Holdings Rate Base Outlook



Note: All numbers denote year-end rate base and may not add due to rounding

Exelon Utilities Load



Chicago GMP	0.9%
Chicago Unemployment	6.2%

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

Philadelphia GMP	1.6%
Philadelphia Unemployment	4.7%

2016 load growth is driven by improving economic conditions coupled with solid Residential customer growth, partially offset by weak Non-Petroleum sector Industrial sales & EE

Baltimore GMP	1.1%
Baltimore Unemployment	4.3%

2016 load growth is lower than 2015 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 (May 2016). Assumes 2016 GDP of 1.7% and U.S. unemployment of 4.7%. 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 true-ups.

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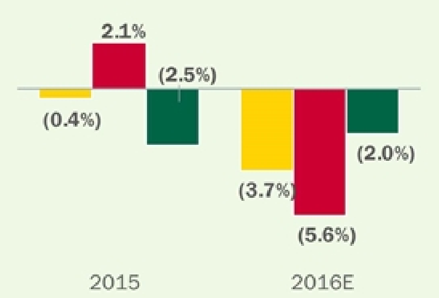
Exelon Utilities Load (cont'd)

All Customers | Residential | C&I

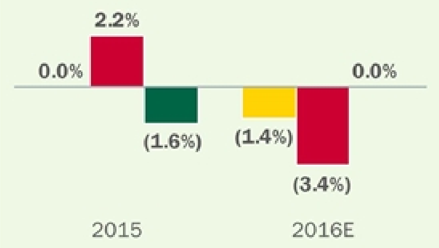
ACE



ACE GMP	1.5%
ACE Unemployment	7.9%

2016 load is driven by the impacts of energy efficiency and continued economic weakness, partially offset by improving customer growth driven by improvement in economic conditions outside of Atlantic City

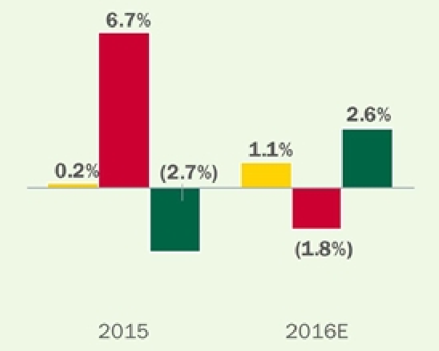
Delmarva



DPL GMP	2.7%
DPL Unemployment	4.7%

2016 load is driven by the impacts of lower usage at significant industrial customers and energy efficiency partially offset by improved employment and customer growth

Pepco



Pepco GMP	1.6%
Pepco Unemployment	4.9%

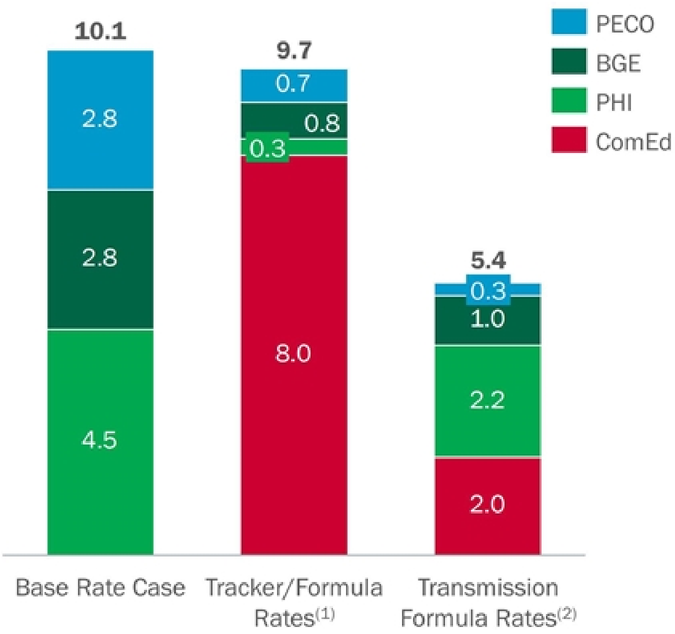
2016 load is driven by improved commercial usage and residential customer growth partially offset by the impacts of energy efficiency and distributed energy

~65% of 2016 forecast distribution revenue is decoupled for PHI

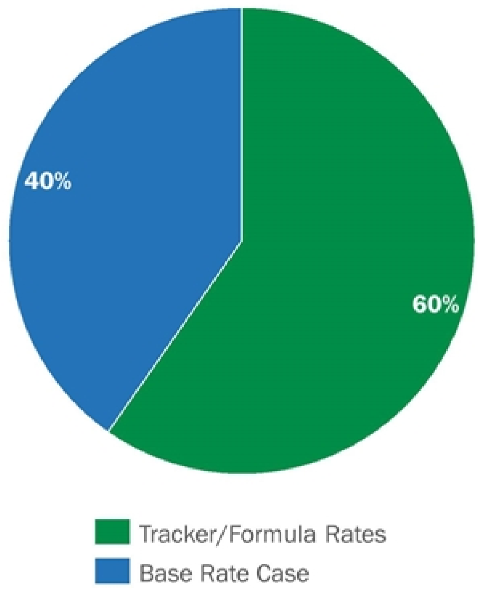
Notes: Data is weather normalized using 20-year historical average and not adjusted for leap year. Source of economic outlook data is IHS (May 2016). Assumes 2016 GDP of 1.7% and U.S. unemployment rate of 4.7%. Pepco and DPL MD are decoupled which mitigates the load risk. QTD and YTD actual data can 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. Pepco reclassified certain customer classes in DC from C&I to Residential in 2015. Excluding the impacts of the re-class, 2015 Residential load growth would have been 2.7% and C&I load growth would have been (0.9%).

Utility Capital Spend Profile (2016–2020)

Capital Spend 2016-2020 (in $B)



Recovery Mechanism: Formulaic or Base Rate Case



Of the approximately $25 billion of capital Exelon Utilities is expected to spend over the next 5 years, 60% will be recovered through existing formula and tracker mechanisms

(1) Assumes renewal of ComEd formula rate in 2019
(2) Assumes PECO FERC transmission formula rate beginning in 2018

Exelon's Policy Priorities

Bill Von Hoene

Senior Executive Vice President & Chief Strategy Officer

Kathleen Barrón

Senior Vice President Federal Regulatory Affairs and Wholesale Market Policy

Exelon.

Exelon Policy Priorities

Modernize Utility Ratemaking to Ensure Appropriate Recovery

- Invest in infrastructure that provides customer benefit through grid resiliency and efficiency
- Ensure fair rate structures to support new technologies

Secure Proper Policies to Enable Innovative Technologies

- Providing new technologies to respond to customer needs
- Open adjacent customer facing markets to sales and services

Recognize the Value of Zero-Carbon Electricity

- Create support for current challenged plants through federal and state initiatives
- Support the ultimate pricing of carbon in the market on a national level

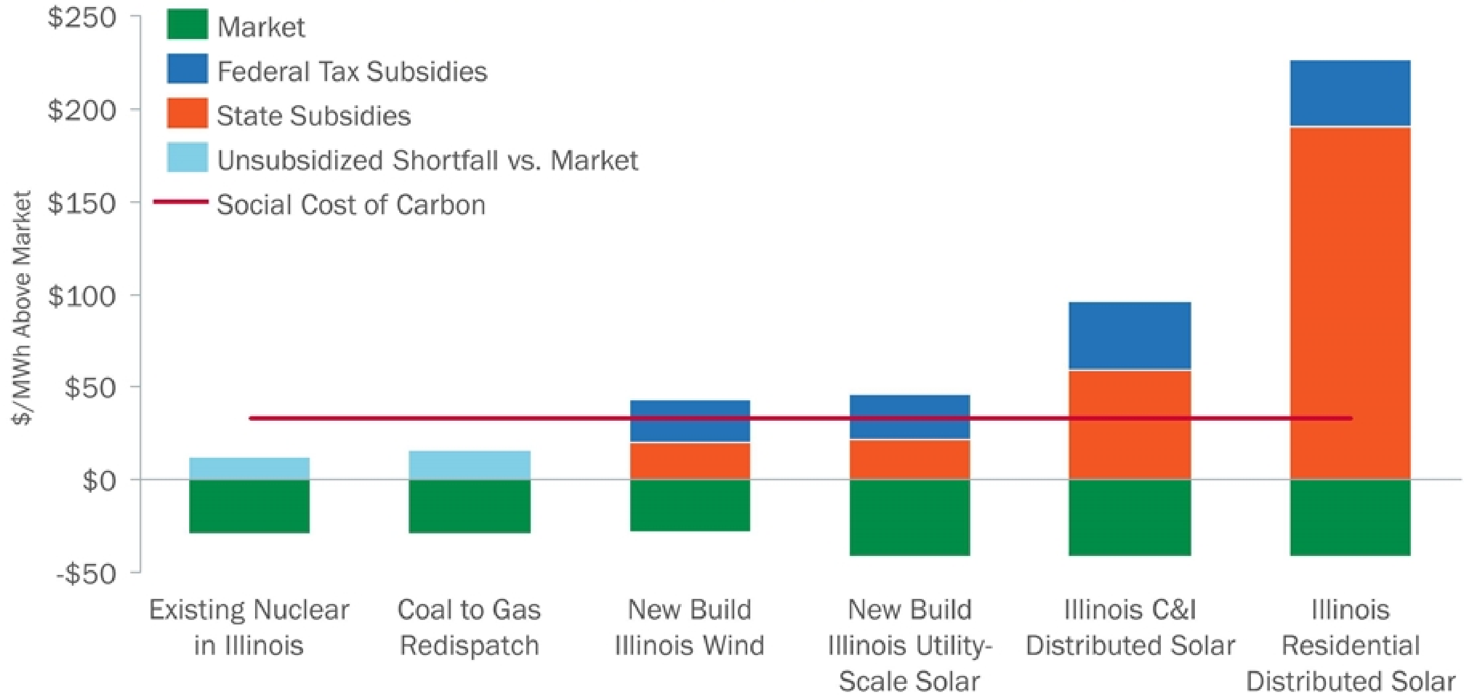
Regulatory and policy structure that supports clean, affordable and reliable options for all customers

Our Carbon Policy Principles

- **Exelon believes in our nation's ability to transition the generation fleet to a zero-carbon future while maintaining affordable and reliable electric service for consumers**
- For the foreseeable future, the most cost-effective carbon solution for our customers will be the continued operation of our nation's nuclear fleet
- Exelon believes competitive markets produce superior results for consumers and drive innovation. However, those markets do not currently incorporate appropriate pricing for environmental attributes.
- **Exelon is pursuing a two-part strategy for moving toward a more competitive treatment of CO_2 emissions:**
  - **First, we must maintain nuclear units that provide a cost effective form of CO_2 abatement.** The New York ZEC program demonstrates that as long as the clean energy payment required to maintain operations at existing nuclear units is lower than the social cost of CO_2 emissions and the cost of CO_2 abatement being paid to other zero carbon resources, maintaining nuclear capacity should be selected as the most competitive source of CO_2 abatement.
  - **Second, we must continue to work toward a technology neutral price of CO_2 abatement.** Exelon is pursuing approaches to reflect a uniform price on CO_2 in wholesale markets as an eventual substitute for technology-specific subsidies. As these approaches are phased in, the ZEC programs have been designed to automatically reduce ZEC payments in response to higher energy prices.

Existing Nuclear is the Most Cost Effective Zero Carbon Choice

Estimated Carbon Price Needed to Preserve Existing Nuclear, Coal to Gas Redispatch and Renewable Entry at Near-Term Technology Costs



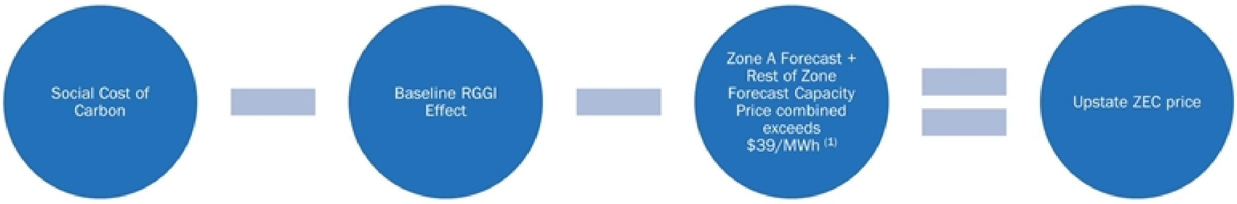
Carbon Price Needed (1)	$16	<$20	$54	$58	$121	$286

(1) $/MWh above-market converted to carbon price needed using PJM marginal emission rate of 1,590 lbs/MWh

Exelon.

New York Zero Emission Credit Program Mechanics

- Pricing for each tranche to be administratively determined based on the USIWG Social Cost of Carbon (escalating over the term), less a fixed baseline for carbon pricing already captured through the RGGI program ($10.41/short ton)
- Tranche 1 yields $17.48/MWh
- Tranches 2-6 shall incorporate a customer protection feature to determine the ZEC. In general, the formula is:



- The quantity of ZECs to be purchased on an annual basis will be capped at a MWh amount that represents the verifiable historic contribution the facility has made to the clean energy resource mix
- Each Load Serving Entity shall be required to purchase an amount of ZECs equivalent to its load ratio share of the total electric energy load in the New York Control Area
- Cost recovery from ratepayers shall be incorporated into the commodity charges on customer bills
- ZECs will not be tradable except between NYSERDA and the LSE in the balancing process

(1) The $39/MWh reference price will be updated at the time the Tranche 4 ZEC price is determined. This one-time update will be calculated by determining the historical basis over the 2017-2022 time period and adjusting the $39/MWh reference price used in the ZEC price formula if the historic basis is outside of a range of $5-7/MWh

Zero Emission Credits (ZECs) are Like Renewable Energy Credits (RECs)

Both credits are for environmental attributes to meet a state environmental goal

While legal challenges are likely, we believe that ZECs, like RECs, will withstand legal challenge:

- No affiliate contracts (Ohio)
- No attempt to alter FERC wholesale rate (NJ/MD)
- Payment for ZECs is not “tethered” to action in a FERC jurisdictional market

FERC has never applied the Minimum Offer Price Rule (MOPR) to existing resources; it has always been a tool to address state support for new entry

Presidential Politics

CLINTON

TRUMP

Policy Outlook: Key Issues Facing the Next President

- Climate Change including Clean Power Plan Implementation
- Budget & Entitlement Reform
- Comprehensive Tax Reform
- Appointees to Supreme Court, DOE, EPA, FERC and NRC
- Federal Nuclear Waste Policy

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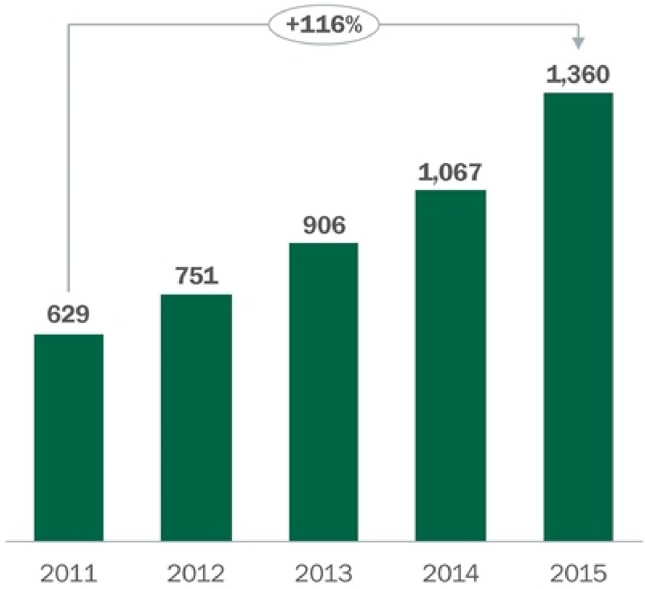
Commitment to Diversity & Inclusion

- **Exelon is focused on attracting, retaining and advancing employees who will best serve and represent our customers, partners and communities**
- In 2015, Exelon surpassed its goals for the inclusion of diverse suppliers:
  - Purchasing almost **$1.4 billion** in goods and services from diversity-certified suppliers
  - Representing **16 percent** of supply-managed expenditures for services and materials
- More than **$2B** invested with minority and women-owned investment firms across our retirement plans
- Exelon arranged credit lines totaling **$123 million** with 28 minority and community-owned banks in Illinois, Pennsylvania, Maryland, and New Jersey

Diversity Certified Supplier Spend ($M)



Exelon's Policies Priorities Appendix

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Overview of New York Zero Emission Credit Program

- On August 1, the New York Public Service Commission (NY PSC) approved the New York Clean Energy Standard which creates a Zero Emission Credit (ZEC) program
- The objective of the program is to preserve the environmental attributes of zero-emissions nuclear-powered generating facilities
- The program creates a 12 year contract extending from April 1, 2017 through March 31, 2029
- The NY PSC will determine whether a plant is eligible based on the following factors:
  - The verifiable historic contribution of the facility to the clean energy resource mix in New York State;
  - The degree to which energy, capacity, and ancillary services revenues projected to be received by the facility are at a level expected to preserve its environmental attributes;
  - The costs/benefits of such attributes in relation to other clean energy alternatives;
  - Impact of related costs on ratepayers; and,
  - The public interest
- The NYPSC found in its August 1 order that the Ginna, Nine Mile Point and Fitzpatrick nuclear plants meet this public interest standard and qualify for the program
- The New York State Energy Research & Development Authority (NYSERDA) will centrally procure the ZECs
- ZECs will be procured in 6, two-year tranches

ZEC Price Determination

Tranche	Date	US SCC "Central Value"	Baseline RGGI Estimate	Net CO2 Externality	Short Ton to MWh	Adjusted SCC	Zone A Reference Price	Energy and Capacity Forecast Adjustment	Upstate ZEC Price
		$ /Short Ton	$ /Short Ton	$ /Short Ton	Conversion Factor	$/MWh	$/MWh	$/MWh	$/MWh
Tranche 1	4/1/2017-3/31/2019	$42.87	$10.41	$32.47	0.53846	$17.48	N/A	N/A	$17.48
Tranche 2	4/1/2019-3/31/2021	$46.79	$10.41	$36.38	0.53846	$19.59	$39.00	TBD	TBD
Tranche 3	4/1/2021-3/31/2023	$50.11	$10.41	$39.71	0.53846	$21.38	$39.00	TBD	TBD
Tranche 4	4/1/2023-3/31/2025	$54.66	$10.41	$44.26	TBD	TBD	TBD	TBD	TBD
Tranche 5	4/1/2025-3/31/2027	$59.54	$10.41	$49.13	TBD	TBD	Tranche 4 amount	TBD	TBD
Tranche 6	4/1/2027-3/31/2029	$64.54	$10.41	$54.13	TBD	TBD	Tranche 4 amount	TBD	TBD

Exelon Generation

Overview

Ken Cornew

President & Chief Executive Officer,
Exelon Generation

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Exelon Generation Overview

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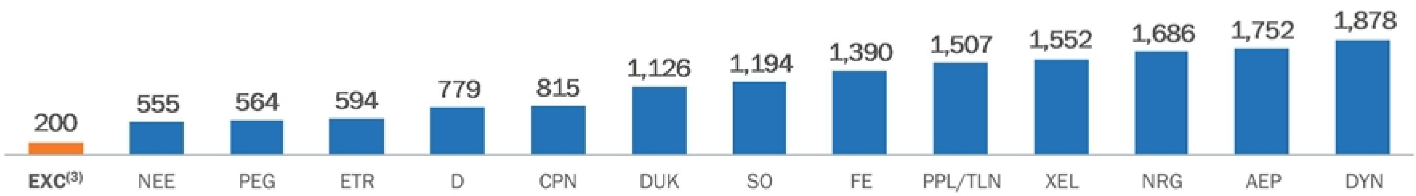
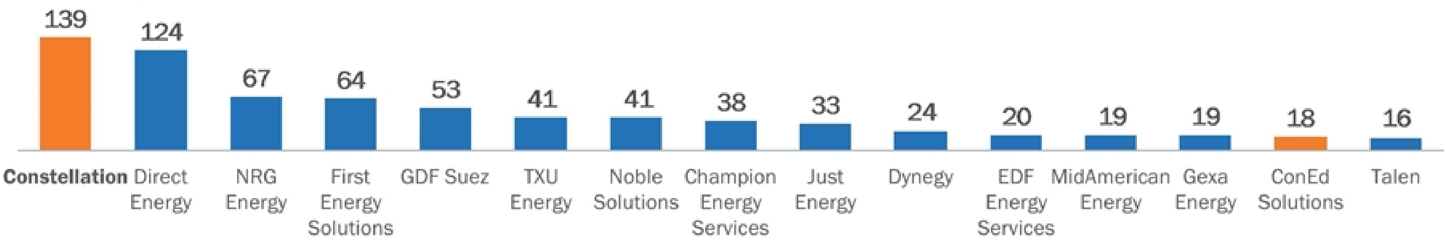
Exelon Generation is an Industry Leader

Total Generation Output (TWh)(1)

Carbon Intensity (lb/MWh)(1)



Retail Load Served (TWhs)(2)



(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

Gen to Load Matching Model being Pursued Across the Sector

Exelon merged with Constellation to match Exelon's long generation position with Constellation's short customer book

Exelon

- **2002:** Constellation New Energy created from purchase of AES New Energy
- Various Acquisitions
- **2011:** Startex and MX Energy acquired
- **2012:** Exelon and Constellation Merger
- **2014:** Integrys Energy Services acquired
- **July 2016:** Announced ConEdison Solutions acquisition(1)

Competitors' Retail Acquisitions:

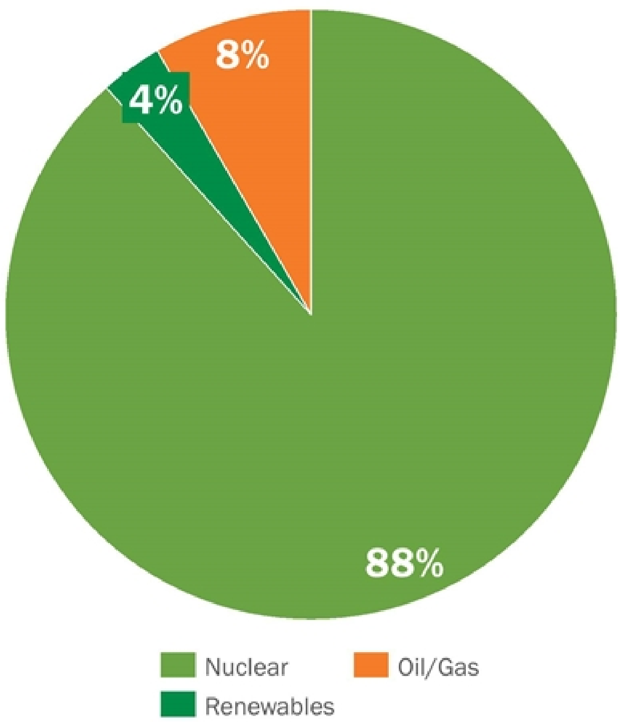
- **NRG**
  - 2011: Energy Plus
  - 2014: Dominion Retail Electric
- **Dynegy**
  - 2013: Ameren Energy Resources
  - 2015: Duke Midwest Retail Book
- **Calpine**
  - 2015: Champion Energy Services
- **PSEG**
  - 2015: Announced they were looking to acquire retail platform

Our proven generation to load matching strategy has delivered sustainable earnings in volatile markets and served as a model for the industry

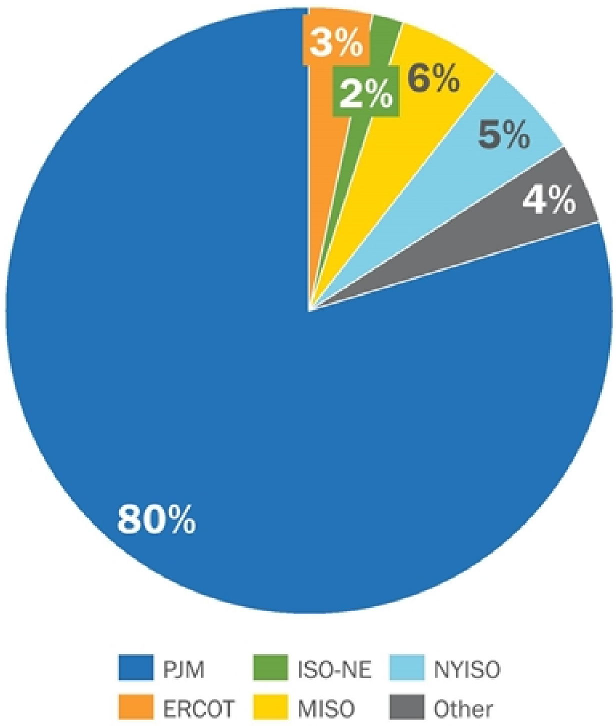
(1) Expected to close by end of 2016

The Cleanest Fleet in the Most Functional Markets

2015 Generation Output by Fuel Type



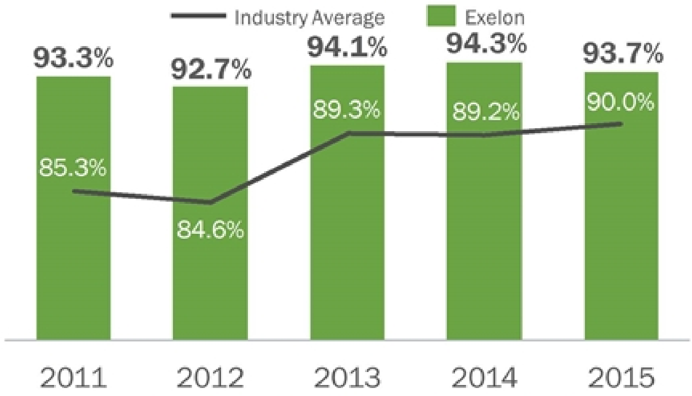
2015 Generation Output by ISO



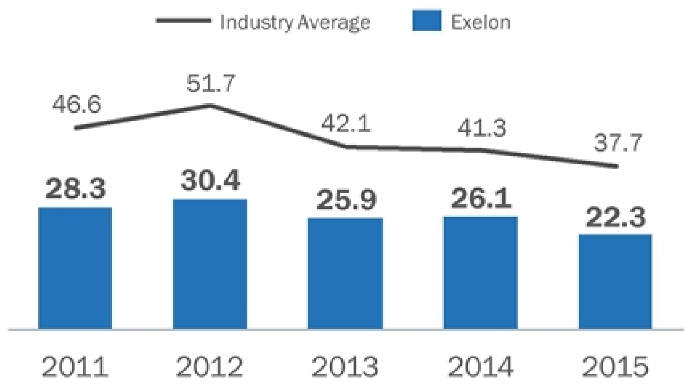
~90% of Exelon's generation is carbon-free and 93% in RTOs with a capacity construct

Best in Class Operational Performance

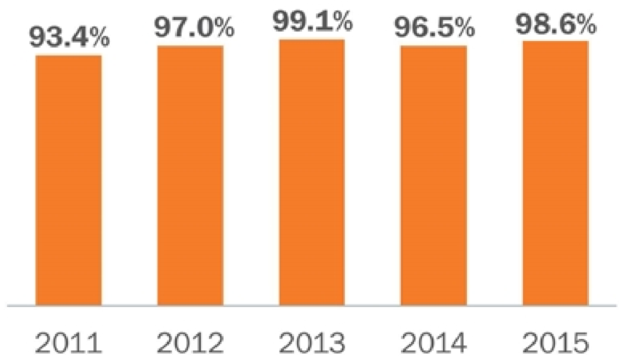
Nuclear Capacity Factor (1)



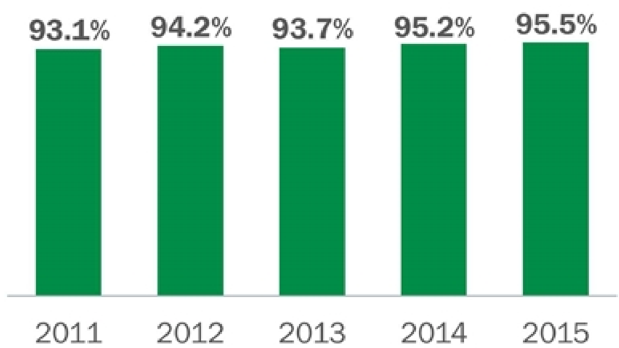
Average Nuclear Refueling Days



Gas & Hydro Dispatch Match



Wind/Solar Energy Capture

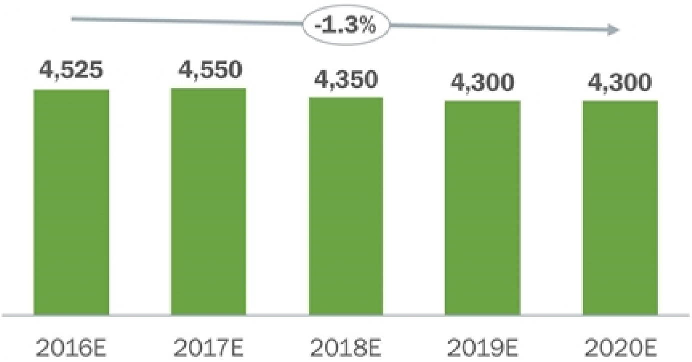


Our leading nuclear capacity factor produced 6 TWh more power than if at industry average

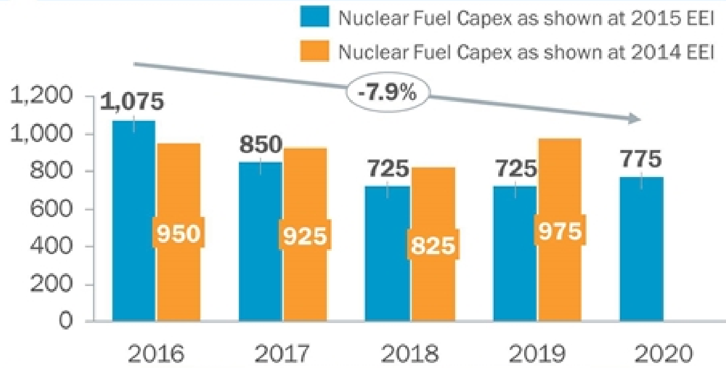
(1) Includes CENG beginning in April 2014, excludes Salem and Fort Calhoun; Calculation of industry average capacity factor and refueling days excludes Exelon fleet

Driving Cost and Capital Out of the Business

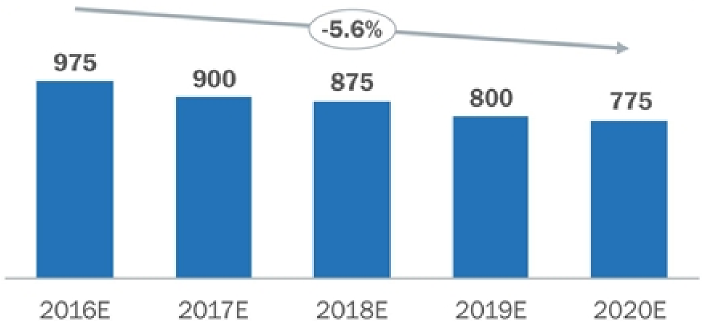
ExGen Adjusted O&M Spend ($M)[1]



Nuclear Fuel Spend ($M)



ExGen Base Capital Spend ($M)[2]



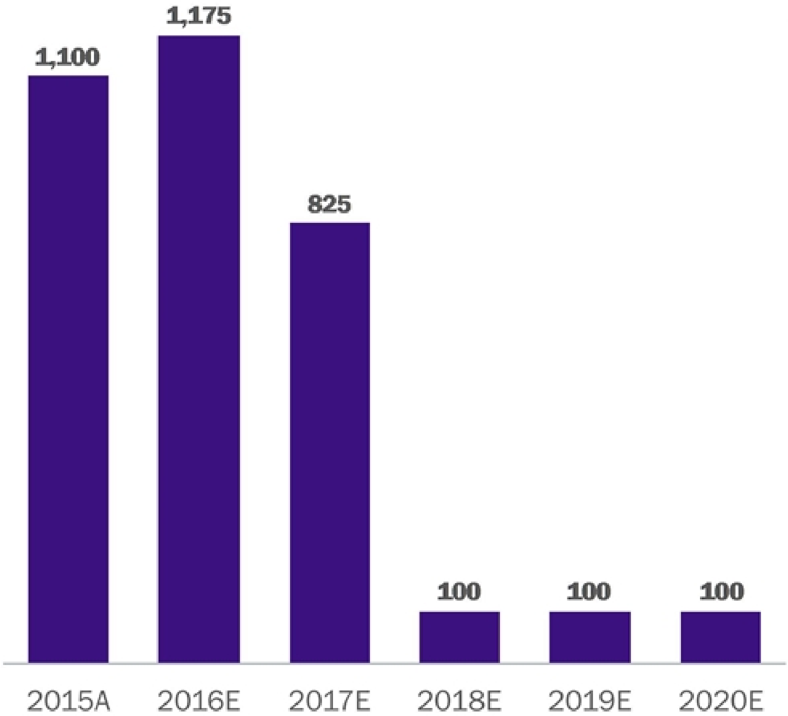
Disciplined approach to cost management drove 2015 Nuclear fleet-wide average total generating cost of $31.58 per MWh, which is top quartile in the industry

(1) Refer to slide 168 in the appendix for a reconciliation of adjusted (non-GAAP) O&M to GAAP O&M

(2) Base capital spend represents cash CapEx with CENG at 100%, excludes merger commitments, and reflects retirement of Clinton and Quad Cities

Growth CapEx Slowing

Exelon Generation Growth Capital Expenditures 2015-2020 ($B)(1)



Growth Project	In-Service Date	Contracted Asset
Blue Stem Wind	2016	Yes
Albany Green Energy	2017	Yes
Texas CCGTs	2017	No
Michigan Wind 3	2017	Yes
West Medway(2)	2018	No

Invest in select contracted assets where we can meaningfully exceed our return thresholds

(1) Includes cash CapEx with CENG at 100%, excludes merger commitments ,and nuclear fuel CapEx is rounded to the nearest $25M
(2) 7-year capacity payments make the project break-even based on a simple payback

Disciplined Portfolio Management to Optimize Value

Demonstrated ability to monetize assets to improve the value of Exelon Generation

Opportunistically Sell Assets

- Sold 3,000 MWs at an average price of $600/kW – raised $1.8B (pre-tax) in asset sales in 2014

Extract Value Through Project Finance

- Raised $3.3B in project finance since 2011 including:
  - $1,050M Continental/EGR1 (13 contracted wind assets) and $700M ExGen Texas Power (3,476 MWs of gas-fired units)

Retire Uneconomic Assets

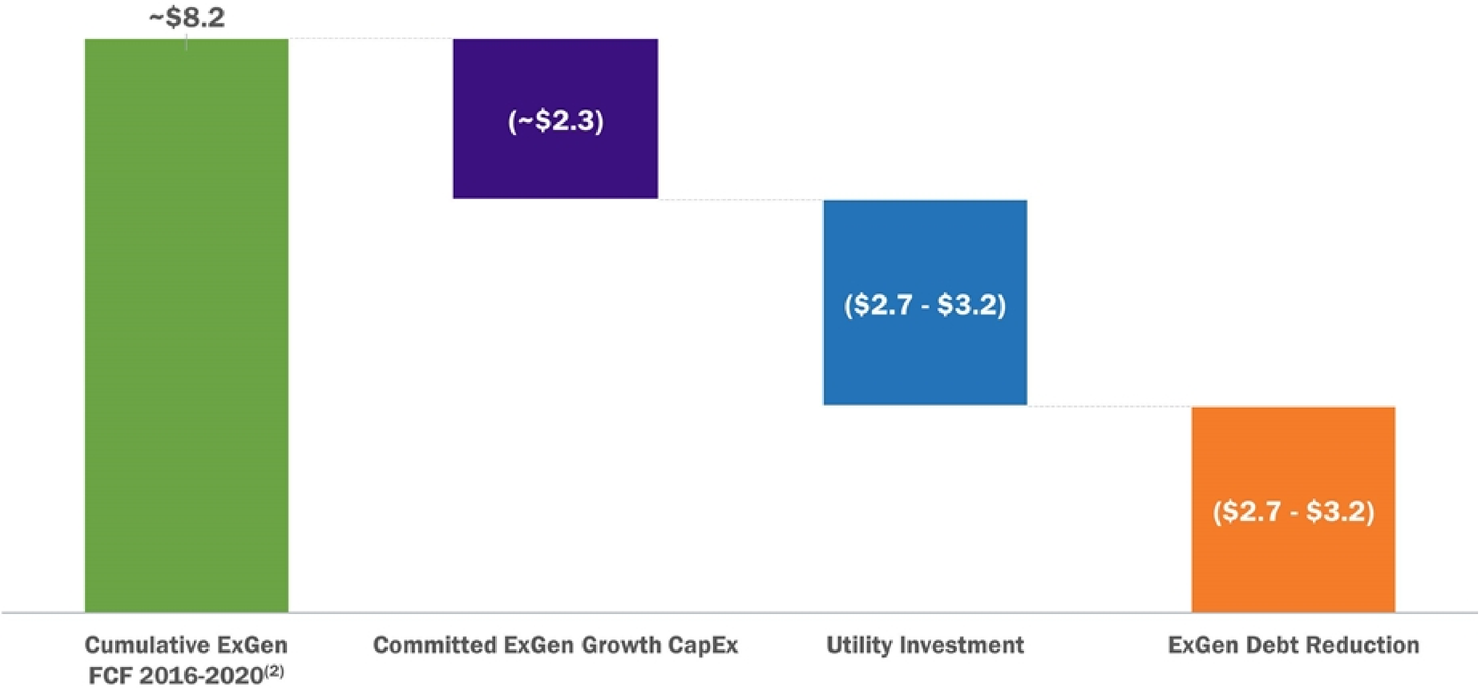
- Planned retirements of Clinton, Quad Cities and Oyster Creek Nuclear Stations in 2017, 2018, and 2019, respectively
- Retired 1,350 MWs of fossil generation from 2011-2016

Payment for Carbon Free Attributes

- NY ZEC program provides payment for carbon free generation
- Committed to pursue compensation for this value across the fleet

ExGen's Strong Free Cash Flow Supports Utility Growth and Debt Reduction

2016-2020 Exelon Generation Free Cash Flow(1,2,3) and Uses of Cash ($B)



Redeploying Exelon Generation's free cash flow to maximize shareholder value

(1) Free Cash Flow is a non-GAAP Measure. See slide 168 for a reconciliation of free cash flow to the most comparable GAAP measures.
(2) Cumulative Free Cash Flow is a midpoint of a range based on June 30, 2016 market prices. It includes ~$700M of other sources including change in margin, tax parent benefit, equity investments, and acquisitions and divestitures.
(3) Approval of Clean Energy Standard (CES) in NY would add up to ~$750M of incremental cash (after-tax) through 2020. This incremental cash is comprised of payments from the CES program ($350M) and additional distributions to Exelon from CENG related to completion of loan repayment and special distribution.

Diverging Paths for Economically Challenged Nuclear Plants

Some Nuclear plants are challenged by persistently low power prices and market designs that do not compensate for their carbon free attributes

New York establishes CES, preserving at-risk nuclear plants, including Ginna and Nine Mile

- **2,600** jobs saved
- **$3B** in NY GDP contributed
- **~$47M** in property taxes preserved
- Prevention of **16MMt** of additional carbon emissions

Illinois fails to reach legislative solution leading to the closure of Clinton and Quad Cities stations

- **4,200** jobs lost
- **$1.2B** in economic activity lost
- **29-43%** of the property tax revenues of surrounding local governments lost
- **20MMt** in additional carbon emissions released

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; New York's Upstate Nuclear Power Plant's Contribution to the State Economy, Mark Berkman and Dean Murphy (The Brattle Group) authors, December 2015

Investing in Our Future Employees through STEM Education

Exelon is making significant investments in science, technology, engineering and math (STEM) education because it is key to the success of our businesses and communities

- **$8M** to support STEM education programs in 2015
- Reaching more than **150,000 students** at hundreds of schools

Exelon.

Constellation

Joe Nigro

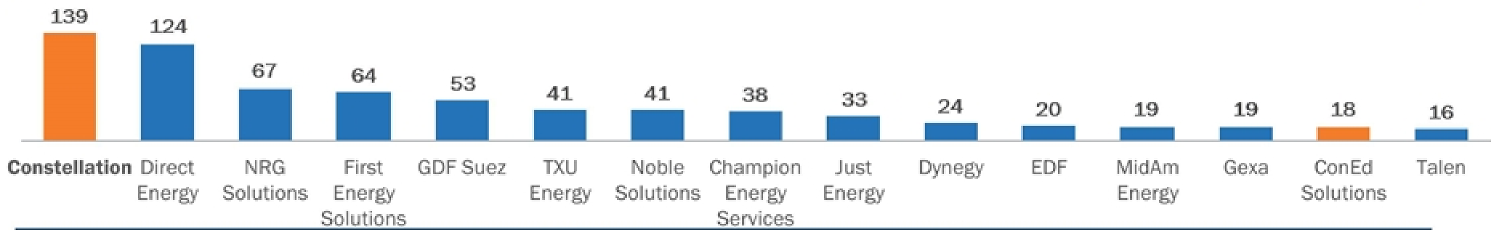
Chief Executive Officer, Constellation

Constellation Overview

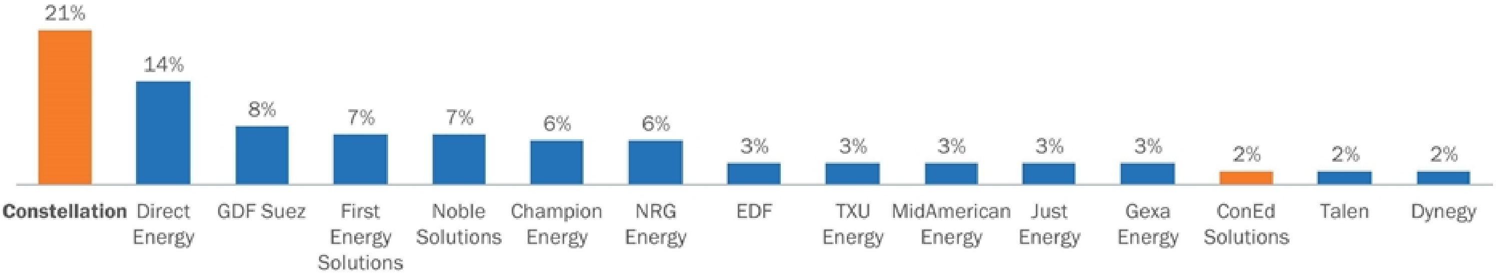
(1) As calculated based on the same generation supply mix used in EPA eGRID 2012

Constellation is an Industry Leader

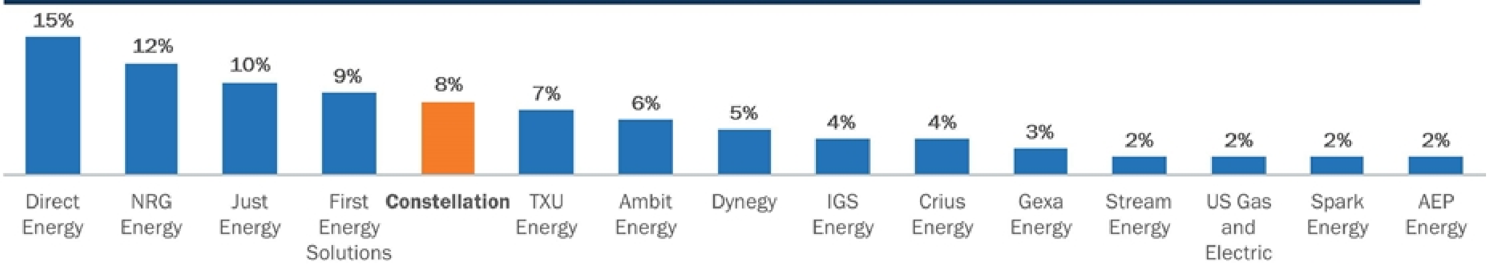
Retail Electric Load Served (TWh)(1)



Non-Residential Market Share(1)



Residential Market Share(1)



(1) Source: DNV GL Retail Landscape April 2016. Numbers reflect annualized customer load under contract.

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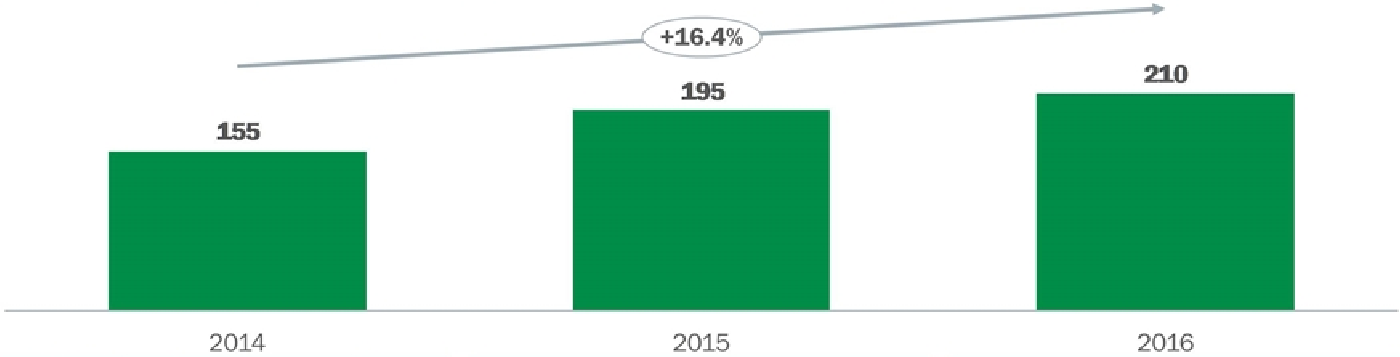
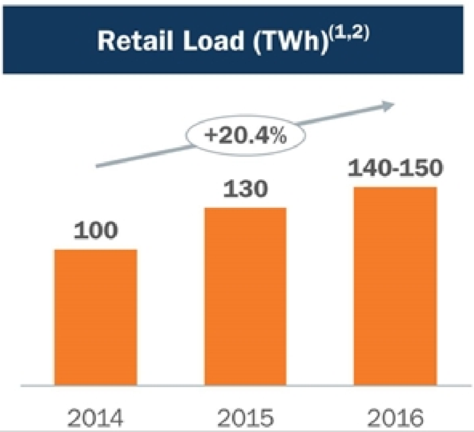
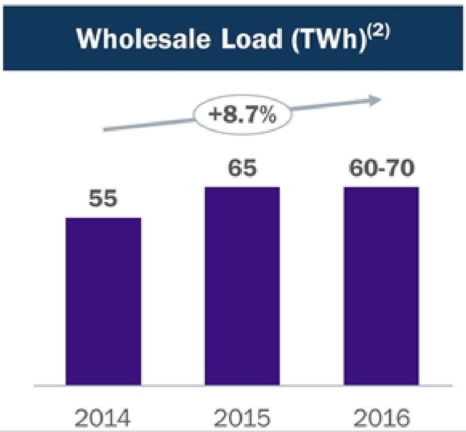
Load Serving Business Growing through Multiple Channels

Total Load Served Volume Growth from 2014 to 2016 at 16.4% CAGR





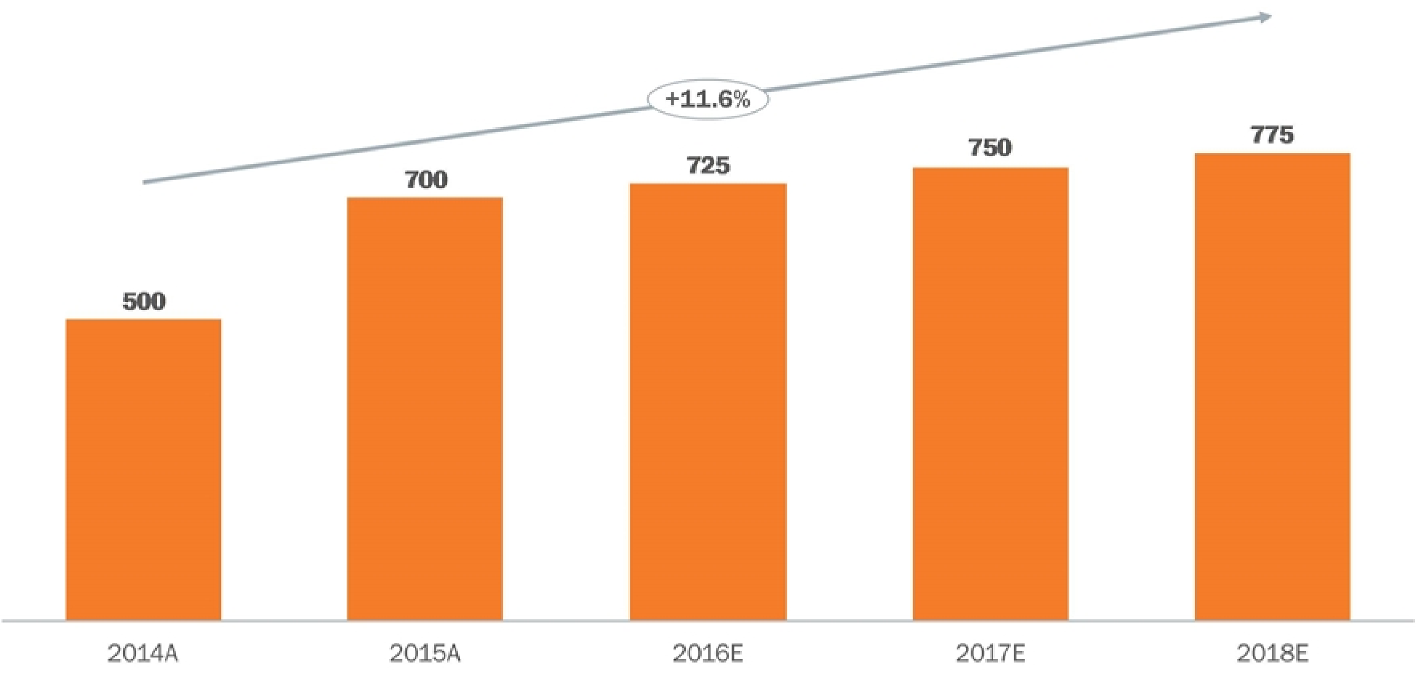


Constellation remains number one in C&I load served and is number five in Residential customers served

(1) Retail load includes index products
(2) Historical volumes are rounded to nearest 5 TWh

Retail Gas Complements our Electric Load Serving Business

Retail Gas Volumes Projections (Bcf)



Constellation has grown its gas business through disciplined M&A and strong customer retention rates

Note: Volumes rounded to nearest 25 Bcf

Loyalty of Constellation Customers

Serve 2/3 of the Fortune 100

Retail Power	Retail Gas	Solar	Distributed Generation
More than **130 TWh**	More than **700 Bcf**	**275 MW**	**165 MW**
retail load under contract in 2015	natural gas under contract in 2015	customer sited, completed or under construction	customer sited, completed or under construction

80% retail power customer renewal rate

30% power new customer win rate

90% natural gas customer retention rate

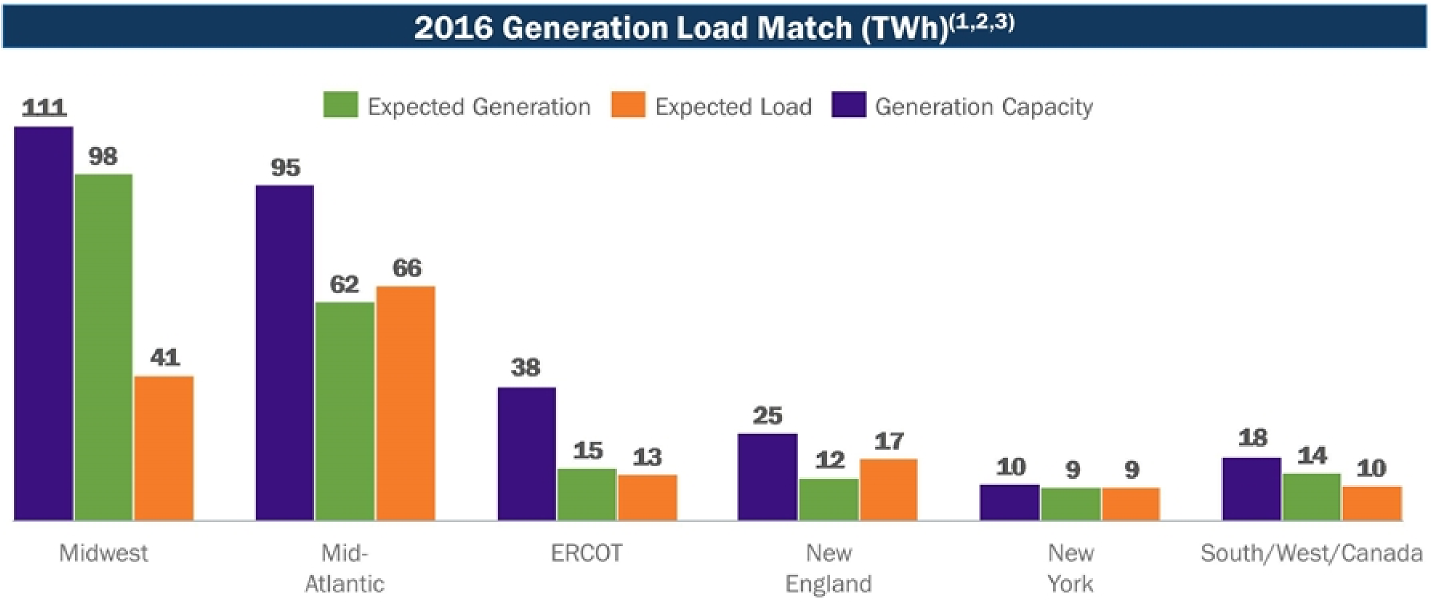
25 month average power contract term

Average customer duration of more than **5** years

Stable Retail Margins

Constellation's retail business has helped drive consistent earnings over the years

Our Generation to Load Strategy Delivers Durable Earnings



- **High volatility**: During periods of high volatility, generation availability is of utmost importance. During the polar vortex of 2014, our 2 GW of peaking capability created significant value in the energy and ancillary markets – providing ~**$100 million in value**[4].
- **Low volatility**: During periods of low volatility, we are able to capture higher margins through lower cost to serve our customers and we optimize the value of our dispatchable fleet. **In 2015, we realized ~$250 million in value.**

(1) Owned and contracted generation capacity converted from MW to MWh assuming 100% capacity factor (CF) for all technology types, except for renewable capacity which is shown at estimated CF
(2) Expected generation and load shown in the chart above will not tie out with load volume and ExGen disclosures; Load shown above does not include indexed products and generation reflects a net owned and contracted position; Estimates as of June 30, 2016
(3) Does not include ConEd Solutions acquisition
(4) Excludes the impact of plant outages, primarily at Calvert Cliffs prior to us operating the plant

Exelon Generation Appendix

Nuclear Output and Refueling Outages

Nuclear Refueling Cycle

- All Exelon-owned units are on a 24 month cycle except:
  - For Braidwood U1/U2, Byron U1/U2, Ginna, and Salem U1/U2, which are on 18 month cycles; and,
  - Clinton which is scheduled on a 12 month cycle; however no refueling outages are scheduled due to its June 1, 2017 retirement date

2017 Planned Refueling Cycle

- 14 planned refueling outages, including 2 at Salem
  - 8 spring refueling outages and 4 fall refueling outages
  - Spring and fall Salem refueling outages

Planned Unit Retirements Impacting Production

- Clinton will be retired in mid-2017
- Quad Cities 1 & 2 will be retired in mid-2018
- Oyster Creek will be retired in late 2019

2018 Refueling Outage Impact

- 12 planned refueling outages, including 1 at Salem
  - 5 spring refueling outages and 6 fall refueling outages
  - 1 Salem fall refueling outages

Additional License Extension for Peach Bottom Station

- On June 7, 2016, Exelon announced it is seeking an additional 20-year operating license for Peach Bottom from the Nuclear Regulatory Commission (NRC)
- The current operating licenses will expire in 2033 and 2034
- If the license extensions are approved, the plants would be allowed to operate until 2053 and 2054
- Exelon will file formal application for license extension in 2018. The NRC review is anticipated to take approximately 2 to 2.5 years to complete
- Peach Bottom is one of Exelon's highest performing plants and one of the best in the United States
  - 93% capacity factor in 2015
  - Long history of reliability
    - No automatic trips in more than 10 years
    - 5 consecutive breaker to breaker runs
  - Provides 10% of Pennsylvania's power
  - Completed major extended power uprate in 2015, under budget and ahead of schedule, that increased site output by more than 12%

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Process for Decommissioning a Nuclear Plant

- Sites must be decommissioned within 60 years of plant ceasing operations
- Exelon must submit a cost estimate for decommissioning the plants to the NRC within 2 years of permanent cessation of operations
- Within 2 years of permanent cessation of operations, Exelon must submit a post-shutdown decommissioning activities report (PSDAR) to the NRC and Illinois, which must include the site's planned option for decommissioning the unit
- NRC will make the PSDAR available for public comment and schedule a public meeting
- Exelon can begin decommissioning activities after 90 days of submitting the PSDAR and after submittal of certification of permanent cessation of operations and permanent removal of fuel
- Exelon cannot access all the decommissioning funds until after submittal of the site-specific cost to the NRC
- Exelon can use one or both of two options to decommission the plants:
    - SAFSTOR (Safe Storage): facility is placed and maintained in a condition that allows it to be safely stored and subsequently decontaminated to levels that permits the property to be released. We can choose to end SAFSTOR at any point during the 60-year period and transition to DECON. Generally, sites must spend no more than 50 years in SAFSTOR and allow 10 years for the DECON stage of decommissioning.
    - DECON (Decontamination): Radioactive equipment and structures are removed or decontaminated to a level that permits the property to be released for use shortly after cessation of operations
- Terminating the NRC license: As the DECON phase nears completion, the company must submit a license termination plan to the NRC at least two years before the proposed license termination date. The license termination plan is subject to public comment. After considering the public comments, the NRC will terminate the license if all work has followed the approved license termination plan and the final radiation survey shows the site is suitable for release.

Exelon's schedules for decommissioning Clinton and Quad Cities nuclear stations are currently under development

Source: Nuclear Energy Institute

Clinton and Quad Cities Nuclear Decommissioning Trust Funds

It is currently estimated that Clinton will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the nuclear decommissioning trust fund (NDTF) investments could appreciate in value. Quad Cities would also be at risk for such a shortfall. A shortfall could require Exelon to post parental guarantees for Generation's obligations. However, the amount of any required guarantees will ultimately be dependent on the decommissioning approach adopted at each site, the associated level of costs, and the decommissioning trust fund investment performance going forward. Considering the three alternative decommissioning approaches available to Generation for each site, the most costly estimates currently anticipated could require parental guarantees of up to $385 million for Clinton in order to access its NDTF for radiological decommissioning costs. Although Quad Cities is better positioned than Clinton to avoid the need for a parental guarantee, a guarantee of up to $135 million, at Generation's ownership percentage, may be required in order for the site to access its NDTF for radiological decommissioning costs.

Upon issuance of any required financial guarantees, Clinton and Quad Cities would be able to utilize the respective NDTFs for radiological decommissioning costs, which represent the majority of the total expected decommissioning costs. However, the NRC must approve an additional exemption in order for Generation to utilize the NDTF to pay for non-radiological decommissioning costs (i.e. spent fuel management and site restoration costs). If a unit does not receive this exemption, the costs would be borne by the owner(s). Accordingly, based on current projections, it is expected that some portion of the spent fuel management and/or site restoration costs would need to be funded through supplemental cash from Generation and others holding ownership interests. While the ultimate amounts may vary greatly and could be reduced by alternate decommissioning scenarios and/or reimbursement of certain costs under the United States Department of Energy reimbursement agreements or future litigation, across the three alternative decommissioning approaches available to Generation, for the next 10 years, Clinton could incur spent fuel management and site restoration costs of up to $160 million, net of taxes. Quad Cities is better positioned to pass the test than Clinton. Although considered unlikely, if Quad Cities fails the exemption test, at its ownership percentage Generation, could be required to pay for spent fuel management costs over the next ten years of up to $185 million, net of taxes.

	Potential Parental Guarantees	Potential Spent Fuel and Restoration Costs
Clinton	Up to $385M	Up to $160M
Quad Cities	Up to $135M	Up to $185M

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Constellation Energy Nuclear Group (CENG) Operating Service Agreement Terms

- **Nuclear Operating services agreement**
  - Integrated CENG and its 3 plants into Exelon Nuclear with transfer of operating licenses
- **Loan to CENG and distributions to EDF/Exelon Generation**
  - CENG $400M special distribution paid to EDF on April 1, 2014
  - Exelon Generation made $400M loan to CENG at 5.25% annual interest rate to fund special distribution to EDF (As of June 30, 2016, the loan balance, including interest, was $308M)
  - Exelon Generation receives priority payment from CENG's available cash flows until loan is fully repaid
  - Exelon Generation also entitled to receive aggregate preferred distributions of $400M plus a return of 8.5% per annum from April 1, 2014 (No amounts have been paid on this special distribution)
- **Option for EDF to sell its 49.99% interest in CENG to Exelon Generation**
  - Exercisable from January 2016 to June 2022
  - Process and timeline allows for possible negotiated agreement on price
  - If no negotiated agreement on price, price is determined by arbitration process to determine fair market value
  - Arbitration process could take up to 10 months or longer before binding decision is made on price
  - Price would be adjusted for EDF share of remaining loan balance and special distribution to Exelon Generation
  - Regulatory approvals could take several months but might run concurrently with arbitration process
  - Exelon has limited rights to defer closing up to 6 months

Capacity Market: PJM

PJM Capacity Revenues(1,2,3)

(1) Revenues reflect capacity cleared in Base, CP transitional & incremental auctions and are for calendar years
(2) Revenues reflect owned and contracted generation
(3) Reflects 50.01% ownership at CENG
(4) Volumes at ownership and rounded

Cleared Volumes(4)	2018/2019				2019/2020			
	CP	Price	Base	Price	CP	Price	Base	Price
COMED								
Nuclear	8,625	$215	-	$200	6,925	$203	-	$183
Fossil/Others	-	$215	25	$200	-	$203	50	$183
Sub Total	8,625		25		6,925		50	
EMAAC								
Nuclear	4,325	$225	-	$211	4,375	$120	-	$100
Fossil/Others	2,075	$225	1,050	$211	1,525	$120	1,675	$100
Sub Total	6,400		1,050		5,900		1,675	
SWMAAC								
Nuclear	850	$165	-	$150	850	$100	-	$80
Fossil/Others	-	$165	-	$150	0	$100	-	$80
Sub Total	850		-		850		-	
BGE								
Nuclear	-	$165	-	$150	0	$100	-	$80
Fossil/Others	300	$165	425	$150	375	$100	225	$80
Sub Total	300		425		375		225	
Rest of RTO								
Nuclear	-	$165	-	$150	0	$100	-	$80
Fossil/Others	265	$165	50	$150	275	$100	75	$80
Sub Total	265		50		275		75	
PJM Portfolio								
Nuclear	13,800		-		12,150		-	
Fossil/Others	2,640		1,550		2,175		2,025	
Grand Total	16,440		1,550		14,325		2,025	

Capacity Markets: ISO-NE, NYISO, MISO

	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020
ISO-NE(1)					
NEMA					
Capacity (MW)(3)	2,100	2,100	2,100	2,100	2,100
Price ($/MWd)	$104	$222	$500	$318	$234
SEMA					
Capacity (MW)(3)	35	35	35	230	230
Price ($/MWd)	$104	$105	$234	$557	$536
NYISO(2)					
Capacity (MW)(3)	1,100	1,100	1,100	1,100	1,100
MISO					
Capacity (MW)(3)	1,100	1,100			
Price ($/MWd)(4)	$150	$72			

(1) ISO-NE: ISO New England; NEMA: Northeastern Massachusetts and Boston; SEMA: Southeastern Massachusetts
(2) NYISO: New York Independent System Operator
(3) Represents offered capacity at ownership
(4) AMIL: Ameren Illinois AMIL capacity price represents PRA auction clearing price for Zone 4 in $/MWd

Exelon Nuclear Fleet Overview (including CENG and Salem)

Region	Plant Location	Type/ Containment	Net Generation Capacity (MW)[1]	License Extension Status / License Expiration[1]	Ownership	Spent Fuel Storage/ Date to lose full core discharge capacity[3]
Midwest	Braidwood, IL (Units 1 and 2)	PWR Concrete/Steel Lined	2,389	Renewed / 2046, 2047	100%	Dry Cask
	Byron, IL (Units 1 and 2)	PWR Concrete/Steel Lined	2,347	Renewed / 2044, 2046	100%	Dry Cask
	Clinton, IL (Unit 1)	BWR Concrete/Steel Lined / Mark III	1,069	2026 [3]	100%	Dry Cask (2016)
	Dresden, IL (Units 2 and 3)	BWR Steel Vessel / Mark I	1,845	Renewed / 2029, 2031	100%	Dry Cask
	LaSalle, IL (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	2,320	Filed application December 2014 (decision expected 2017)/2022, 2023	100%	Dry Cask
	Quad Cities, IL (Units 1 and 2)	BWR Steel Vessel / Mark I	1,403	Renewed / 2032 [3]	75% Exelon, 25% Mid-American Holdings	Dry Cask
Mid-Atlantic	Limerick, PA (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	2,317	Renewed / 2044, 2049	100%	Dry Cask
	Oyster Creek, NJ (Unit 1)	BWR Steel Vessel / Mark I	625	Renewed / 2029 [4]	100%	Dry Cask
	Peach Bottom, PA (Units 2 and 3)	BWR Steel Vessel / Mark I	1,299	Renewed / 2033, 2034	50% Exelon, 50% PSEG	Dry Cask
	TMI, PA (Unit 1)	PWR Concrete/Steel Lined	837	Renewed / 2034	100%	2023
	Salem, NJ (Units 1 and 2)	PWR Concrete/Steel Lined	1,005	Renewed / 2036, 2040	42.6% Exelon, 57.4% PSEG	Dry Cask
CENG	Calvert Cliffs, MD (Units 1and 2)	PWR Concrete/Steel Lined	878	Renewed / 2034, 2036	100% CENG [5]	Dry Cask
	R.E. Ginna, NY (Unit 1)	PWR Concrete/Steel Lined	288	Renewed / 2029	100% CENG [5]	Dry Cask
	Nine Mile Point, NY (Units 1 and 2)	BWR Steel Vessel / Mark I Concrete/Steel Vessel/ Mark II	838	Renewed / 2029, 2046	100% CENG[5] / 82% CENG[5], 18% Long Island Power Authority	Dry Cask

(1) Net generation capacity is stated at proportionate ownership share. As of December 31, 2015. Operating license renewal process takes approximately 4-5 years from commencement until completion of NRC review.
(2) The date for loss of full core reserve identifies when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core; Dry cask storage will be in operation at those sites prior to losing full core discharge capacity in their on-site storage pools
(3) On June 2, 2016, Exelon announced plans to permanently cease generation operations at Clinton on June 1, 2017 and Quad Cities on June 1, 2018
(4) On December 8, 2010, Exelon announced that it will permanently cease generation operations at Oyster Creek by December 31, 2019; Oyster Creek's current NRC license expires in 2029
(5) Exelon Generation has a 50.01% ownership interest in CENG. EDF has a 49.99% ownership interest in CENG.

Exelon Oil & Gas Generation Fleet Overview

Region	Station	Location	Number of Units	Primary Fuel Type	Percent Owned(1)	Net Generation Capacity (MW)(2)
ERCOT	Colorado Bend	Wharton, TX	6	Gas		468
ERCOT	Handley 3	Fort Worth, TX	1	Gas		395
ERCOT	Handley 4, 5	Fort Worth, TX	2	Gas		870
ERCOT	LaPorte	Laporte, TX	4	Gas		152
ERCOT	Mountain Creek 6, 7	Dallas, TX	2	Gas		240
ERCOT	Mountain Creek 8	Dallas, TX	1	Gas		568
ERCOT	Wolf Hollow 1, 2, 3	Granbury, TX	3	Gas		705
Mid-Atlantic	Chester	Chester, PA	3	Oil		39
Mid-Atlantic	Croydon	West Bristol, PA	8	Oil		391
Mid-Atlantic	Delaware	Philadelphia, PA	4	Oil		56
Mid-Atlantic	Eddystone	Eddystone, PA	4	Oil		60
Mid-Atlantic	Eddystone 3, 4	Eddystone, PA	2	Oil/Gas		760
Mid-Atlantic	Falls	Morrisville, PA	3	Oil		51
Mid-Atlantic	Gould Street	Baltimore, MD	1	Gas		97
Mid-Atlantic	Handsome Lake	Kennerdell, PA	5	Gas		268
Mid-Atlantic	Moser	Lower PottsgroveTwp., PA	3	Oil		51

Region	Station	Location	Number of Units	Primary Fuel Type	Percent Owned(1)	Net Generation Capacity (MW)(2)
Mid-Atlantic	Notch Cliff	Baltimore, MD	8	Gas		118
Mid-Atlantic	Perryman	Belcamp, MD	5	Oil/Gas		412
Mid-Atlantic	Philadelphia Road	Baltimore, MD	4	Oil		61
Mid-Atlantic	Richmond	Philadelphia, PA	2	Oil		98
Mid-Atlantic	Riverside	Baltimore, MD	2	Oil/Gas		39
Mid-Atlantic	Salem	Lower Alloways Creek Twp, NJ	1	Oil	42.59	16
Mid-Atlantic	Schuylkill	Philadelphia, PA	2	Oil		30
Mid-Atlantic	Southwark	Philadelphia, PA	4	Oil		52
Mid-Atlantic	Westport	Baltimore, MD	1	Gas		116
Midwest	Southeast Chicago	Chicago, IL	8	Gas		296
New England	Framingham	Framingham, MA	3	Oil		31
New England	Medway	West Medway, MA	3	Oil/Gas		123
New England	Mystic 7	Charlestown, MA	1	Oil/Gas		575
New England	Mystic 8, 9	Charlestown, MA	2	Gas		1415
New England	Mystic Jet	Charlestown, MA	1	Oil		8
New England	New Boston(3)	South Boston, MA	1	Oil		16
New England	Wyman	Yarmouth, ME	1	Oil	5.9	36
Other	Grand Prairie	Alberta, Canada	1	Gas		105
Other	Hillabee	Alexander City, AL	1	Gas		753
Other	Sunnyside	Sunnyside, UT	1	Waste Coal	50	26

(1) 100%, unless otherwise indicated
(2) Oil & Gas Capacity values shown represent summer ratings as of June 2016. Net Generation Capacity (MW) is stated at proportionate ownership share.
(3) New Boston Jet (16 MW) will retire in Q4 2016

Exelon Renewable Generation Fleet Overview

Region	Station	Location	Number of Units	Primary Fuel Type	Percent Owned[1]	Net Generation Capacity (MW)[2]
ERCOT/SPP	EXC Wind 1,2,3,4	Hansford Co., TX	62	Wind		110
	EXC Wind 5,6	Sherman Co., TX	16	Wind		20
	EXC Wind 7,8,9,10,11	Moore Co., TX	40	Wind		50
	High Plains	Moore Co., TX	8	Wind	99.5	10
	Sendero	Hebbronville, TX	39	Wind		78
	Whitetail	Webb, TX	57	Wind		91
Mid-Atlantic	Bethlehem Landfill	Bethlehem, PA	1	Landfill Gas		5
	Conowingo	Harford Co., MD	11	Hydroelectric		572
	Criterion	Oakland, MD	28	Wind		70
	Eastern Landfill	White Marsh, MD	3	Landfill Gas		3
	Fair Wind	Garrett, MD	12	Wind		30
	Fairless	Falls Twp, PA	2	Landfill Gas		60
	Fourmile	Garrett Co., MD	16	Wind		40
	Muddy Run	Lancaster Co., PA	8	Hydro		1,070
	Pennsbury	Falls Twp, PA	2	Landfill Gas		6
West	Antelope Valley Solar Ranch	LA County, CA	1	Solar		242
	Cassia	Twin Falls Co., ID	14	Wind		29
	Echo I	Umatilla Co., OR	21	Wind	99	35
	Echo II	Morrow Co., OR	10	Wind		20
	Echo III	Morrow Co., OR	6	Wind	99	10
	High Mesa	Twin Fall Co., ID	19	Wind		40
	Mountain Home	Elsmore Co., ID	20	Wind		42
	Threemile Canyon	Morrow Co., OR	6	Wind		10
	Tuana Springs	Twin Fall Co., ID	8	Wind		17
	Wildcat	Lea, NM	13	Wind		27

Region	Station	Location	Number of Units	Primary Fuel Type	Percent Owned[1]	Net Generation Capacity (MW)[2]
Midwest	AgriWind	Bureau Co., IL	4	Wind	99	8
	Beebe 1A & 1B	Gratiot, MI	55	Wind		131
	Blue Breezes/Moore	Blue Earth, MN	2	Wind		3
	Cisco	Jackson Co., MN	4	Wind	99	8
	Cowell	Pipestone Co., MN	1	Wind	99	2
	CP Windfarm	Faribault Co., MN	2	Wind		4
	Ewington	Jackson Co., MN	10	Wind	99	21
	EXC City Solar	Cook Co., IL	1	Solar		8
	Harvest I & II	Huron Co., MI	65	Wind		112
	Marshall	Lyon Co., MN	9	Wind	99	19
	Michigan Wind I	Bingham Township, MI	46	Wind		69
	Michigan Wind II	Minden City, MI	50	Wind		90
	Bluegrass Ridge	Gentry Co., MO	27	Wind		57
	Conception	Nodaway Co., MO	24	Wind		50
	Cow Branch	Atchinson Co., MO	24	Wind		50
	Greensburg	Kiowa Co., KS	10	Wind		13
	Loess Hills	Atchinson Co., MO	4	Wind		5
	Shooting Star	Kiowa Co., KS	65	Wind		104

(1) 100%, unless otherwise indicated
(2) Renewable Capacity values shown represent summer ratings as of June 2016. Net Generation Capacity (MW) is stated at proportionate ownership share.

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Exelon Generation Disclosures

June 30, 2016

Portfolio Management Strategy

Strategic Policy Alignment

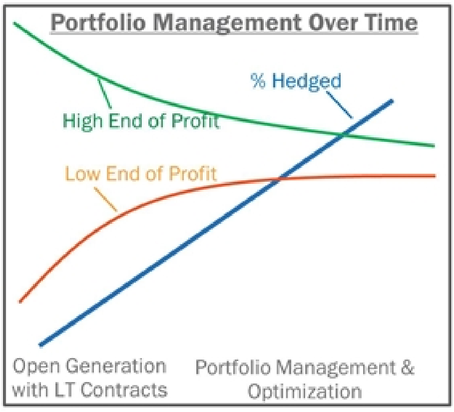
- Aligns hedging program with financial policies and financial outlook
  - Establish minimum hedge targets to meet financial objectives of the company (dividend, credit rating)
  - Hedge enough commodity risk to meet future cash requirements under a stress scenario

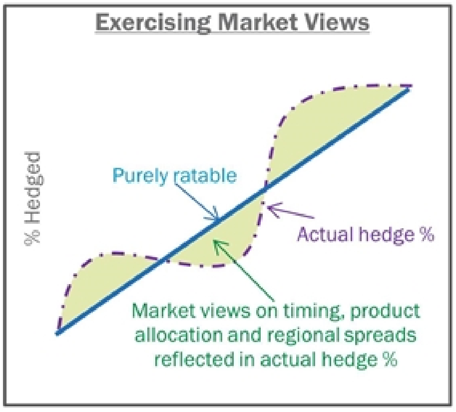
Three-Year Ratable Hedging

- 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





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

- Generation Gross Margin at current market prices, including capacity and ancillary revenues, nuclear fuel amortization and fossils fuels expense
- Power Purchase Agreement (PPA) Costs and Revenues
- Provided at a consolidated level for all regions (includes hedged gross margin for South, West and Canada[1])

MtM of Hedges[2]

- Mark-to-Market (MtM) of power, capacity and ancillary hedges, including cross commodity, retail and wholesale load transactions
- Provided directly at a consolidated level for five major regions. Provided indirectly for each of the five major regions via Effective Realized Energy Price (EREP), reference price, hedge %, expected generation

"Power" New Business

- Retail, Wholesale planned electric sales
- Portfolio Management new business
- Mid marketing new business

"Non Power" Executed

- Retail, Wholesale executed gas sales
- Energy Efficiency[4]
- BGE Home[4]
- Distributed Solar

"Non Power" New Business

- Retail, Wholesale planned gas sales
- Energy Efficiency[4]
- BGE Home[4]
- Distributed Solar
- Portfolio Management / origination fuels new business
- Proprietary trading[3]

Margins move from 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 & 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]	2016	2017	2018
Open Gross Margin (including South, West & Canada hedged GM)[3]	$4,750	$5,650	$5,900
Mark-to-Market of Hedges[3,4]	$2,450	$800	$200
Power New Business / To Go	$150	$700	$900
Non-Power Margins Executed	$350	$150	$100
Non-Power New Business / To Go	$100	$300	$400
Total Gross Margin[2,6]	**$7,800**	**$7,600**	**$7,500**

Reference Prices[5]	2016	2017	2018
Henry Hub Natural Gas ($/MMbtu)	$2.52	$3.18	$3.02
Midwest: NiHub ATC prices ($/MWh)	$26.03	$29.42	$29.71
Mid-Atlantic: PJM-W ATC prices ($/MWh)	$29.80	$34.61	$33.28
ERCOT-N ATC Spark Spread ($/MWh) *HSC Gas, 7.2HR, $2.50 VOM*	$4.87	$5.14	$4.98
New York: NY Zone A ($/MWh)	$28.57	$33.60	$32.31
New England: Mass Hub ATC Spark Spread($/MWh) *ALQN Gas, 7.5HR, $0.50 VOM*	$4.78	$6.97	$8.01

(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. Refer to slide 138 for a reconciliation of Total Gross Margin to the most comparable GAAP measure.

(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, 2016 market conditions

(6) Excludes Clinton and Quad Cities starting in June 2017 and June 2018 respectively. Does not include the impact of the CES program in NY.

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Generation and Hedges	2016	2017	2018
Exp. Gen (GWh)(1)	**196,300**	**199,300**	**190,700**
Midwest (6)	97,800	91,000	80,900
Mid-Atlantic(2)	61,700	60,900	60,600
ERCOT	15,100	26,000	31,100
New York (2)	9,400	9,200	9,100
New England	12,300	12,200	9,000
% of Expected Generation Hedged(3)	97%-100%	78%-81%	47%-50%
Midwest (6)	96%-99%	73%-76%	42%-45%
Mid-Atlantic(2)	100%-103%	88%-91%	53%-56%
ERCOT	96%-99%	81%-84%	49%-52%
New York(2)	107%-110%	63%-66%	62%-65%
New England	88%-91%	67%-70%	36%-39%
Effective Realized Energy Price ($/MWh)(4)			
Midwest (6)	$35.00	$32.50	$31.00
Mid-Atlantic(2)	$46.00	$42.00	$38.50
ERCOT(5)	$11.50	$6.50	$3.50
New York(2)	$56.50	$48.50	$35.50
New England(5)	$26.00	$16.50	$6.50

(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, 14 in 2017, and 12 in 2018 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 94.4%, 93.7% and 93.4% 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

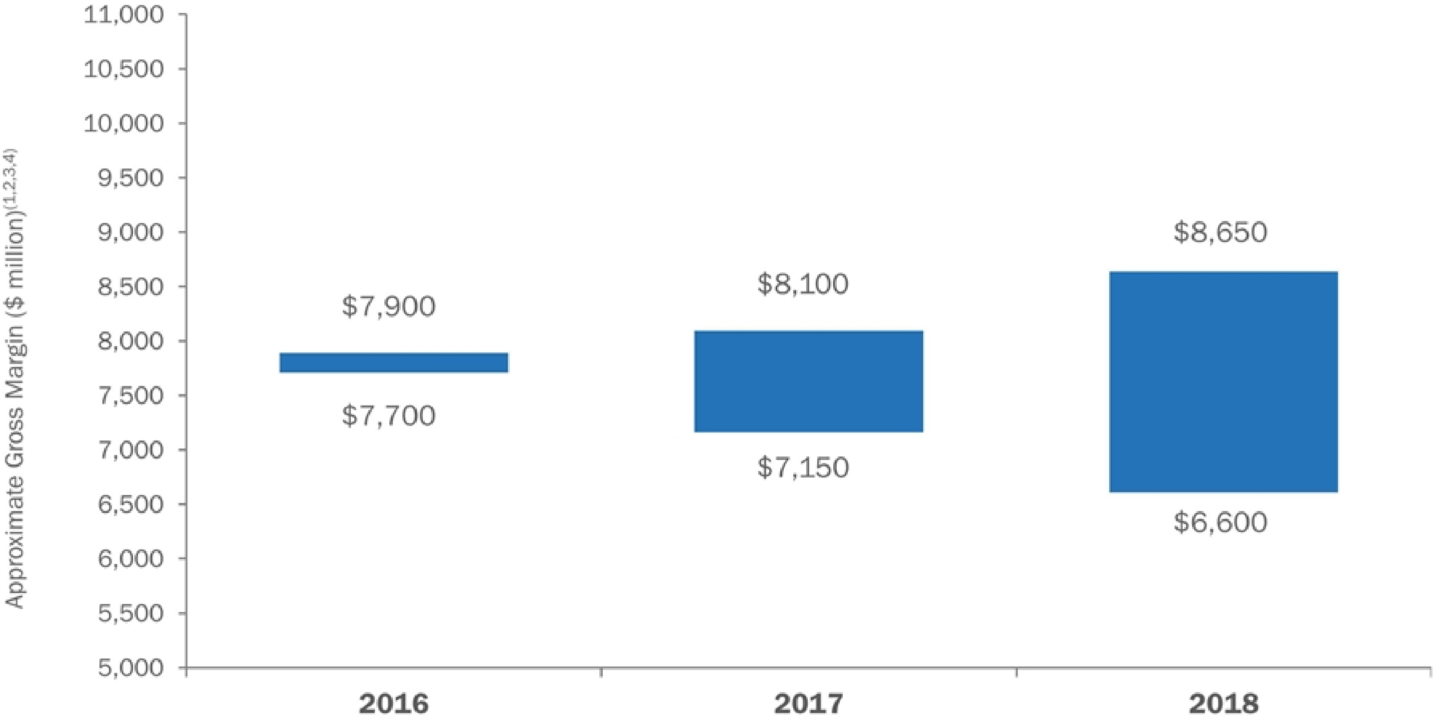
(6) Excludes Clinton and Quad Cities starting in June 2017 and June 2018 respectively. Does not include the impact of the ZEC program in NY. For more information on impacts of these two items please refer to slide 150.

ExGen Hedged Gross Margin Sensitivities

Gross Margin Sensitivities (With Existing Hedges)[1]	2016	2017	2018
Henry Hub Natural Gas ($/Mmbtu)			
+ $1/Mmbtu	$(35)	$120	$305
- $1/Mmbtu	$55	$(115)	$(295)
NiHub ATC Energy Price			
+ $5/MWh	$10	$140	$265
- $5/MWh	$(10)	$(140)	$(260)
PJM-W ATC Energy Price			
+ $5/MWh	$(5)	$35	$125
- $5/MWh	$5	$(30)	$(125)
NYPP Zone A ATC Energy Price			
+ $5/MWh	-	$15	$15
- $5/MWh	-	$(15)	$(15)
Nuclear Capacity Factor			
+/- 1%	+/- $15	+/- $40	+/- $35

(1) Based on June 30, 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. 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. Refer to slide 138 for a reconciliation of Total Gross Margin to the most comparable GAAP measure.

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 June 30, 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 EDF's equity ownership share of the CENG Joint Venture. Refer to slide 138 for a reconciliation of Total Gross Margin to the most comparable GAAP measure.

(4) Excludes Clinton and Quad Cities starting in June 2017 and June 2018 respectively. Does not include the impact of the CES program in NY. For more information on the impacts of these two items please refer to slide 150.

Illustrative Example of Modeling Exelon Generation 2017 Gross Margin

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	$5.65 billion					
(B)	Expected Generation (TWh)	91	60.9	26	9.2	12.2	
(C)	Hedge % (assuming mid-point of range)	74.5%	89.5%	82.5%	64.5%	68.5%	
(D=B*C)	Hedged Volume (TWh)	67.8	54.5	21.5	5.9	8.4	
(E)	Effective Realized Energy Price ($/MWh)	$32.50	$42.00	$6.50	$48.50	$16.50	
(F)	Reference Price ($/MWh)	$29.42	$34.61	$5.14	$33.60	$6.97	
(G=E-F)	Difference ($/MWh)	$3.08	$7.39	$1.36	$14.90	$9.53	
(H=D*G)	Mark-to-market value of hedges ($ million)[1]	$210	$405	$30	$90	$80	
(I=A+H)	Hedged Gross Margin ($ million)	$6,450					
(J)	Power New Business / To Go ($ million)	$700					
(K)	Non-Power Margins Executed ($ million)	$150					
(L)	Non-Power New Business / To Go ($ million)	$300					
(N=I+J+K+L)	Total Gross Margin[2,3]	$7,600 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. Refer to slide 138 for a reconciliation of Total Gross Margin to the most comparable GAAP measure.
(3) Excludes Clinton starting in June 2017. Does not include the impact of the CES program in NY.

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Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in $M)(1)	2016	2017	2018
Revenue Net of Purchased Power and Fuel Expense(2)(3)	**$8,475**	**$8,325**	**$8,175**
Other Revenues(4)	$(325)	$(325)	$(325)
Direct cost of sales incurred to generate revenues for certain Constellation businesses(5)	$(350)	$(400)	$(350)
Total Gross Margin (Non-GAAP)	**$7,800**	**$7,600**	**$7,500**

Key ExGen Modeling Inputs (in $M)(1)(6)	2016
Other Revenues (excluding Gross Receipts Tax)(4)	$225
O&M(7)	$(4,525)
Taxes Other Than Income (TOTI)(8)	$(350)
Depreciation & Amortization(9)	$(1,025)
Interest Expense	$(375)
Effective Tax Rate	**34.0%**

(1) All amounts rounded to the nearest $25M
(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, as to do so would be unduly burdensome. RNF also includes the RNF of our proportionate ownership share of CENG.
(3) Excludes the mark-to-market impact of economic hedging activities due to the volatility and unpredictability of the future changes to power prices
(4) Other revenues 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
(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 slide 168 for a reconciliation of adjusted (non-GAAP) O&M to GAAP O&M.
(8) TOTI excludes gross receipts tax of $100M
(9) Depreciation & Amortization excludes the cost of sales impact of ExGen's non-power businesses of $25M

Financial Update

Jack Thayer

Senior Executive Vice President & Chief Financial Officer

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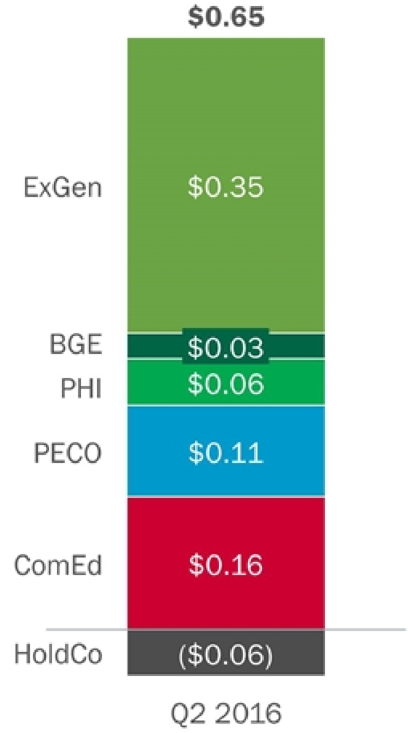
Q2 2016 Financial Results

- Delivered adjusted (non-GAAP) operating earnings in Q2 of $0.65/share, exceeding our guidance range of $0.50-$0.60/share

- Utilities
  - BGE rate case write-offs
  - Higher distribution and transmission revenues
  - Favorable weather

- ExGen
  - Lower cost to serve load
  - Strong performance at Constellation
  - Lower O&M and Decom Realized Gains

Q2 2016 Adjusted Operating EPS Results (1,2)



Expect Q3 2016 Adjusted Operating Earnings of $0.65 - $0.75 per share and reaffirming full-year guidance range of $2.40 - $2.70/share(3,4)

(1) Refer to slides 158 and 159 in the appendix for additional details and to slides 163 and 164 for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS
(2) Amounts may not add due to rounding
(3) 2016 earnings guidance is based on expected average outstanding shares of 926M. Earnings guidance for OpCos may not add up to consolidated EPS guidance.
(4) ComEd ROE based on 30 -year average Treasury yield of 2.49% as of June 30, 2016. 25 basis point move in 30 Year Treasury Rate equates to +/-$0.01 impact to EPS.

Exelon.

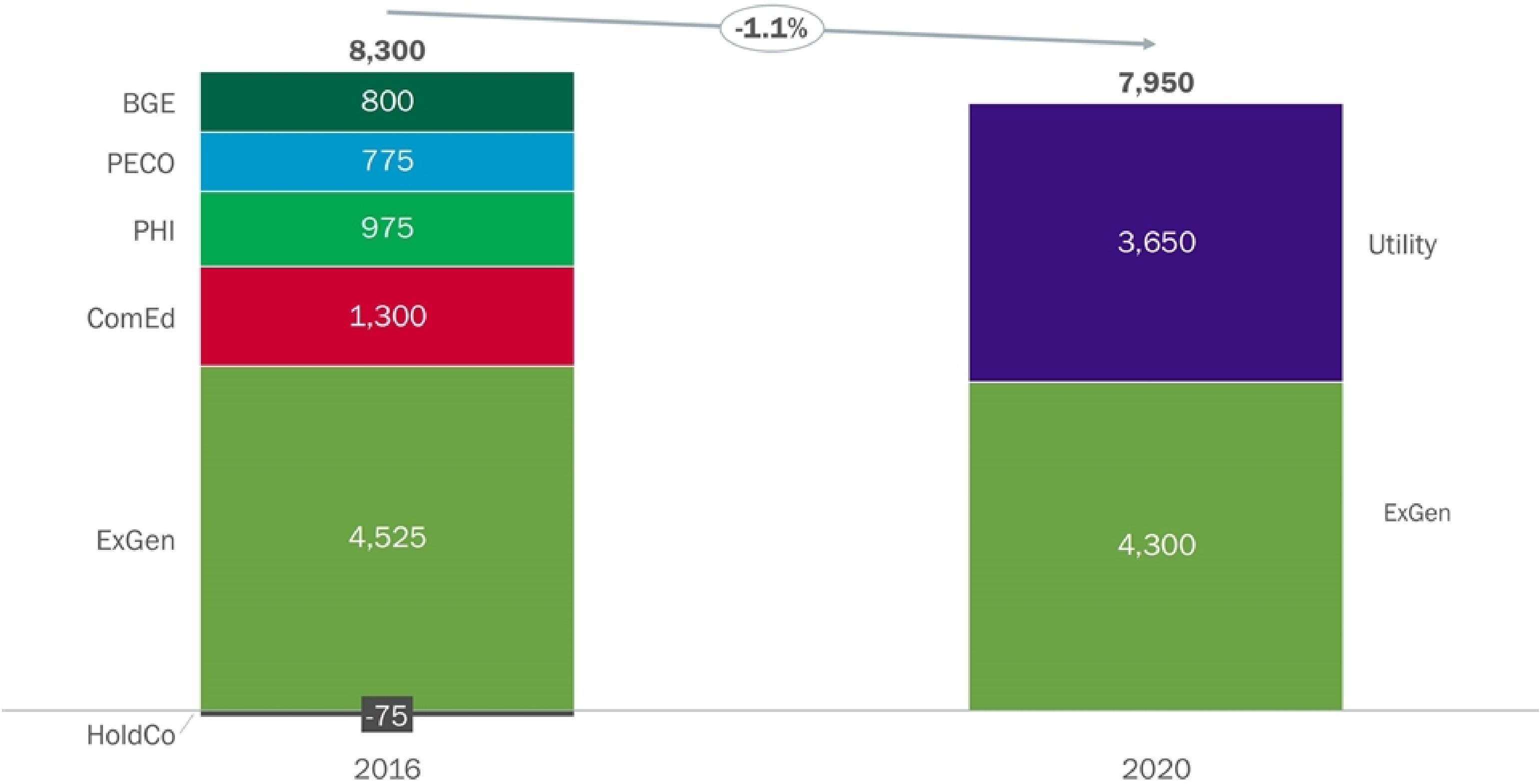
The Exelon Value Proposition

- **Regulated Utility Growth** with utility EPS rising 7-9% annually from 2016-2020 and rate base growth of 6.1%, representing an expanding majority of earnings
- **ExGen's strong free cash generation** will support utility growth while also reducing debt by ~$3B over the next 5 years
- **Optimizing ExGen value by:**
  - Seeking fair compensation for the zero-carbon attributes of our fleet;
  - Closing uneconomic plants;
  - Monetizing assets; and,
  - Maximizing the value of the fleet through our generation to load matching strategy
- **Strong balance sheet is a priority** with all businesses comfortably meeting investment grade credit metrics through the 2020 planning horizon
- **Capital allocation priorities targeting**:
  - Organic utility growth;
  - Return of capital to shareholders with 2.5% annual dividend growth through 2018(1),
  - Debt reduction; and,
  - Modest contracted generation investments

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

Aggressively Managing Costs

Expect Exelon Consolidated O&M ($M) CAGR of ~(1.1%) from 2016-2020[1,2,3]



(1) All amounts rounded to the nearest $25M
(2) Refer to slide 169 in the appendix for a reconciliation of adjusted (non-GAAP) O&M to GAAP O&M. Utilities adjusted O&M excludes regulatory O&M costs that are P&L neutral. ExGen adjusted O&M excludes direct cost of sales for certain Constellation and Power businesses, P&L neutral decommissioning costs and the impact from O&M related to variable interest entities.
(3) 2016 numbers include full year for PHI except for PHI impact on ExGen

Optimizing the Value of Our Generation Fleet

Efficiently Operating Existing Portfolio

- Effectively managing O&M and capital expenses across fleet
- Running plants at best in class capacity factor
- Increasing value of plant output through our generation to load matching strategy

Opportunistically Monetizing Assets

- Raised more than $5B of cash flow through project financing and asset sales since 2011

Successfully Obtaining Recognition of Carbon Free Attributes of Nuclear

- ZEC program in New York recognizes the value of carbon free attributes of our fleet and provides annual EPS benefit of $0.08-0.10 per share and $350M of additional after-tax cash through 2020(1)
- Pursuing recognition for entire fleet

Prudently Retiring Uneconomic Plants

- Retired 1,350 MWs of fossil generation since 2011
- Announced retirement of 3 uneconomic nuclear units from 2017 to 2019. Clinton and Quad Cities retirements result in run-rate savings of up to $0.07 of EPS and $75M in pre-tax cash flow(2)

(1) $350M is solely from implementation of CES program and does not include additional cash benefits from CENG loan repayment and special distribution
(2) Illinois Impacts based on February 29, 2016 pricing and excludes decommissioning costs; New York impacts assume ZEC program implementation and that adjusted social cost of carbon is ZEC price for tranche 2

ExGen's Strong Free Cash Flow Supports Utility Growth and Debt Reduction

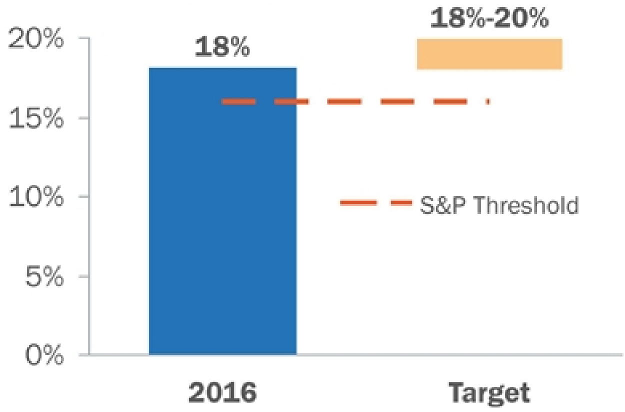
2016-2020 Exelon Generation Free Cash Flow[1,2,3] and Uses of Cash ($B)

Redeploying Exelon Generation's free cash flow to maximize shareholder value

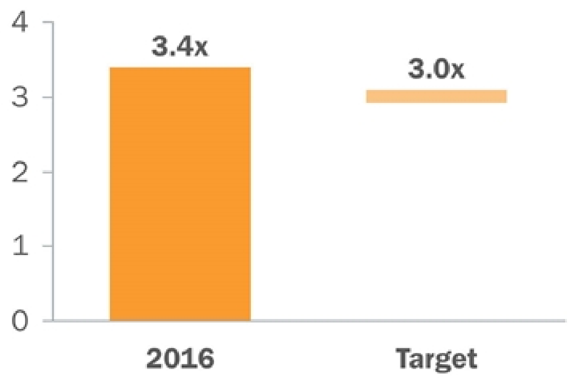
(1) Free Cash Flow is a non-GAAP Measure. See slide 168 for a reconciliation of free cash flow to the most comparable GAAP measures.
(2) Cumulative Free Cash Flow is a midpoint of a range based on June 30, 2016 market prices. It includes ~$700M of other sources including change in margin, tax parent benefit, equity investments, and acquisitions and divestitures.
(3) Approval of Clean Energy Standard (CES) in NY would add up to ~$750M of incremental cash (after-tax) through 2020. This incremental cash is comprised of payments from the CES program ($350M) and additional distributions to Exelon from CENG related to completion of loan repayment and special distribution.

Maintaining Investment Grade Credit Ratings is a Top Financial Priority

Exelon S&P FFO/Debt %(1)(4)



ExGen Debt/EBITDA Ratio(5)



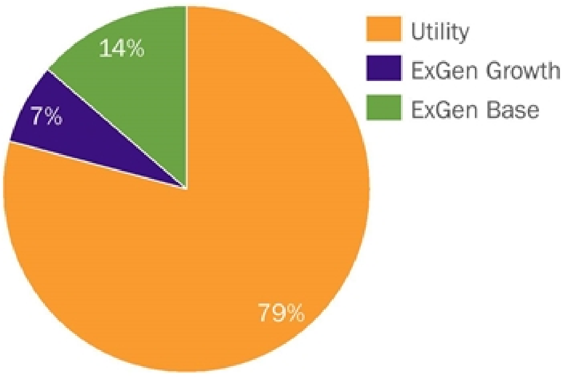
Credit Ratings by Operating Company

Current Ratings (2)(3)	ExCorp	ExGen	ComEd	PECO	BGE	ACE	DPL	Pepco
Moody's	Baa2	Baa2	A2	Aa3	A3	A3	A2	A2
S&P	BBB-	BBB	A-	A-	A-	A	A	A
Fitch	BBB+	BBB	A-	A	A-	A-	A	A-

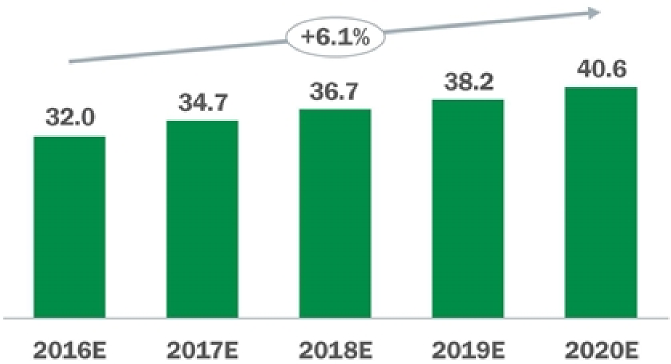
(1) Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment. FFO/Debt is a non-GAAP measure. Please refer to slides 166 and 167 in the appendix for a reconciliation of FFO/Debt to the most comparable GAAP measure.
(2) Current senior unsecured ratings as of June 30, 2016 for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco
(3) All ratings have "Stable" outlook, except for at Moody's, which has ComEd on "Positive" outlook
(4) Exelon Corp downgrade threshold (red dotted line) is based on the S&P Exelon Corp Summary Report; represents minimum level to maintain current Issuer Credit Rating of BBB at Exelon Corp.
(5) Reflects net book debt (YE debt less cash on hand) / adjusted operating EBITDA. EBITDA, a non-GAAP measure, is defined as earnings before interest, taxes, depreciation and amortization. Includes nuclear fuel amortization expense. Please refer to slide 167 for a reconciliation of Debt/EBITDA to the most comparable GAAP measure.

Building Enduring Value

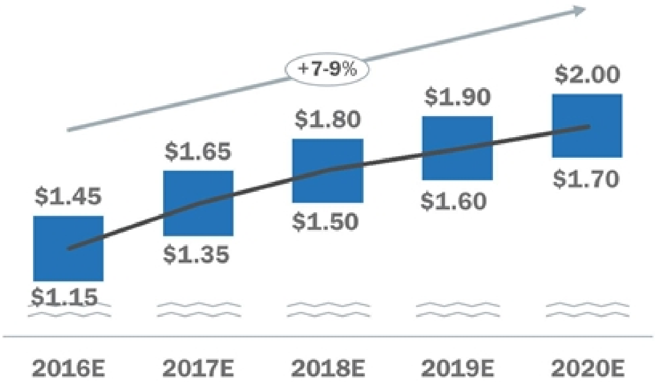
Projected Capital Spend 2016-2020(1)



Rate Base Growth ($B)(2)



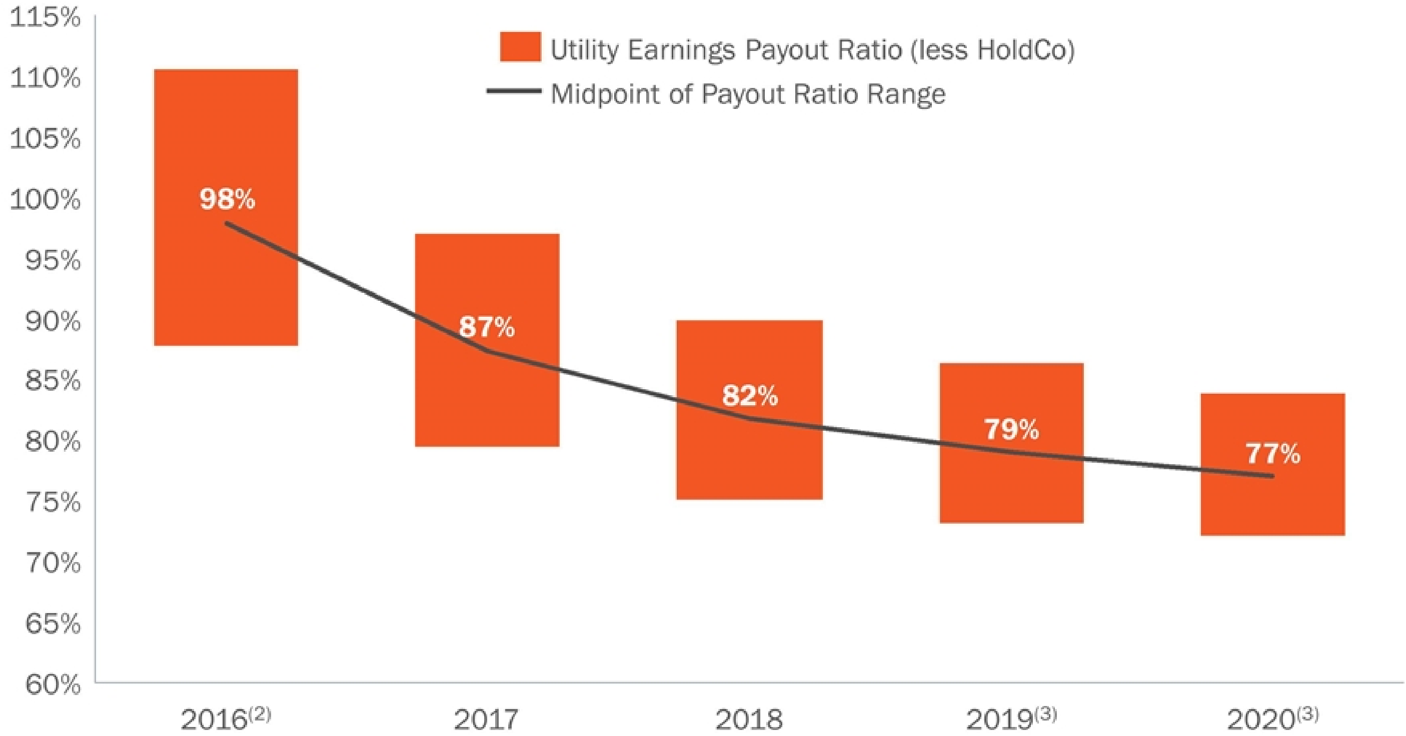
Exelon Utilities Operating Net Income ($M)(3)



(1) ExGen capital represents cash CapEx with CENG 100%; excludes Nuclear Fuel and merger commitments
(2) All numbers denote year-end rate base
(3) Reflects GAAP operating earnings except for 2016. 2016 GAAP EPS range would be $0.65 to $0.95. 2016 adjusted (non-GAAP) operating earnings include adjustments to exclude $0.40 for merger commitments and $0.10 of merger integration costs. Includes after-tax interest expense held at Corporate for debt associated with existing utility investment. 2016 estimate normalized to include a full year for PHI.

Exelon.

Theoretical Dividend Affordability from Utility less HoldCo[1]



Utility less HoldCo payout ratio falling consistently even as dividend grows

(1) Chart is illustrative and shows theoretical payout ratio if utilities supported 100% of the external dividend and interest expense at HoldCo. Currently, the utilities have a payout ratio of 70% which covers the majority of the external dividend and interest expense at HoldCo with ExGen covering the remainder.

(2) 2016 numbers normalized to include full year for PHI

(3) Board of directors has approved a policy of 2.5% per year dividend increase through 2018. For illustrative purposes only, the chart assumes the dividend continues to increase 2.5% per year 2019 and 2020; this does not signal a change in Board policy at this time. Quarterly dividends are subject to declaration by the board of directors.

Delivering Value Through Capital Allocation Policy

Our strong balance sheet underpins our capital allocation policy and capital decisions are made to maximize value to our customers and shareholders

We are **returning capital to shareholders** by growing our dividend, targeting 2.5% annual increases through 2018[1] with upside potential beyond

We are **redeploying free cash flow** from Exelon Generation to support:

- **Investing in utilities** where we can earn an appropriate return and will deploy $25B of capital over the next 5 years
- **Retiring debt** with ~$3B targeted at ExGen over the next 5 years
- **Investing in select contracted assets** where we can meaningfully exceed our return thresholds

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

Financial Appendix

Economic Impacts of Nuclear Plant Retirements and ZEC Program

New York ZEC Program[1]	
Annual Earnings Impact	$0.08 - $0.10
Cumulative Cash Impact through 2020	$350 after-tax

	2016	2017	2018
Gross Margin Impact[2]	$-	$100M	$150M

Illinois Plant Retirements[3]	
2019 Run-Rate Earnings Impact	~$0.07
2019 Run-Rate Cash Flow Impact	$75M pre-tax

	2016	2017	2018
Gross Margin Impact[2]	$-	($100M)	($350M)

(1) $350M is solely from implementation of CES program and does not include additional cash benefits from CENG loan repayment and special distribution
(2) Gross margin categories rounded to nearest $50M. 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.
(3) Impacts based on February 29, 2016 pricing and excludes decommissioning costs

Capital Allocation Evolution

(1) Numbers rounded to nearest $25M and may not add due to rounding
(2) ExGen Figures from 2012-2014 are accrual. CENG CapEx is included beginning April 1, 2014. ExGen figures from 2015-2020 are cash and 100% of total CENG fleet. Nuclear fuel not included. Excludes merger commitments.
(3) 2012 Includes a full year of capital spend for BGE; 2016 includes a full year of capital spend for PHI

2016 Projected Sources and Uses of Cash

($ in millions) (1)	BGE	ComEd	PECO	PHI	Total Utilities	ExGen	Corp(8)	Exelon 2016E	Cash Balance
Beginning Cash Balance(2)									**7,800**
Adjusted Cash Flow from Operations(2,3)	600	1,500	750	775	3,625	3,600	(200)	7,025	
Base CapEx and Nuclear Fuel(4)	0	0	0	0	0	(2,400)	(125)	(2,525)	
Free Cash Flow	**600**	**1,500**	**750**	**775**	**3,625**	**1,200**	**(325)**	**4,500**	
Debt Issuances	750	1,200	300	300	2,550	1,000	1,800	5,350	
Debt Retirements	(575)	(675)	(300)	(325)	(1,875)	0	0	(1,875)	
Project Financing	0	0	0	0	0	50	0	50	
PHI Purchase	0	0	0	0	0	0	(6,925)	(6,925)	
Contribution from Parent	25	625	0	1,550	2,200	0	(2,200)	0	
Other Financing(5)	225	225	25	(900)	(425)	(300)	1,025	300	
Financing	**425**	**1,375**	**25**	**625**	**2,450**	**750**	**(6,300)**	**(3,100)**	
Total Free Cash Flow and Financing Growth	**1,025**	**2,875**	**775**	**1,400**	**6,075**	**1,950**	**(6,625)**	**1,400**	
Utility Investment	(850)	(2,575)	(675)	(1,175)	(5,275)	0	0	(5,275)	
ExGen Growth(4),(6)	0	0	0	0	0	(1,200)	0	(1,200)	
Acquisitions and Divestitures	0	0	0	0	0	100	0	100	
Equity Investments	0	0	0	0	0	(125)	0	(125)	
Dividend(7)	0	0	0	0	0	0	(1,175)	(1,175)	
Other CapEx and Dividend	**(850)**	**(2,575)**	**(675)**	**(1,175)**	**(5,275)**	**(1,225)**	**(1,175)**	**(7,675)**	
Total Cash Flow	**175**	**300**	**100**	**225**	**800**	**725**	**(7,800)**	**(6,275)**	
Ending Cash Balance(1)(2)									**1,525**

(1) All amounts rounded to the nearest $25M. Figures may not add due to rounding.

(2) Excludes counterparty collateral activity.

(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 M&A, and equity investments. Please refer to slide 170 for reconciliations to GAAP cash flow measures.

(4) Figures reflect cash CapEx and CENG fleet at 100%

(5) Other Financing includes expected changes in short-term debt, money pool borrowings, tax sharing from the parent, debt issue costs, and retail energy efficiency contracts.

(6) ExGen Growth CapEx includes Phoenix, West Medway, AGE, Sendero, Nuclear relicensing, Nuclear Uprates, Merger Commitments excl. Solar, Retail Growth & Distributed Energy, Michigan Wind 3, Bluestem Wind, Clinton Battery Storage and MTSA wind turbines

(7) Dividends are subject to declaration by the Board of Directors.

(8) Includes cash flow activity from Holding Company, eliminations, and other corporate entities.

Consistent and reliable free cash flows

Operational excellence and financial discipline drives free cash flow reliability

- ✓ Generating ~$4.5B of free cash flow, including $1.2B at ExGen and $3.6B at the Utilities

Supported by a strong balance sheet

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

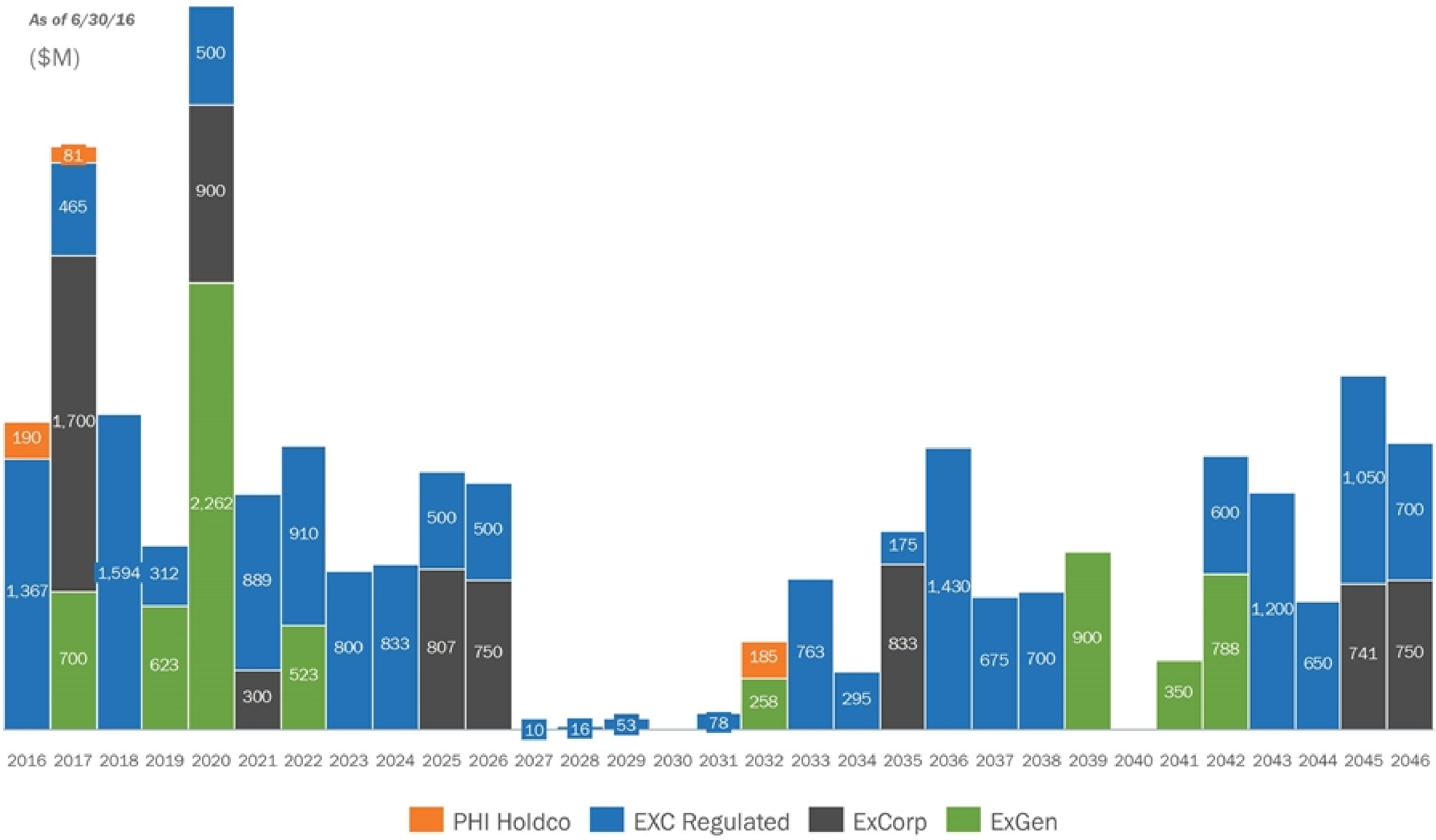
- ✓ Completed $6.9B merger with PHI
- ✓ HoldCo issued $1.8B of Long-term debt in April

Enable growth & value creation

Creating value for customers, communities and shareholders

- ✓ Investing $6.5B, with $5.3B at the Utilities and $1.2B at ExGen

Exelon Debt Maturity Profile(1)

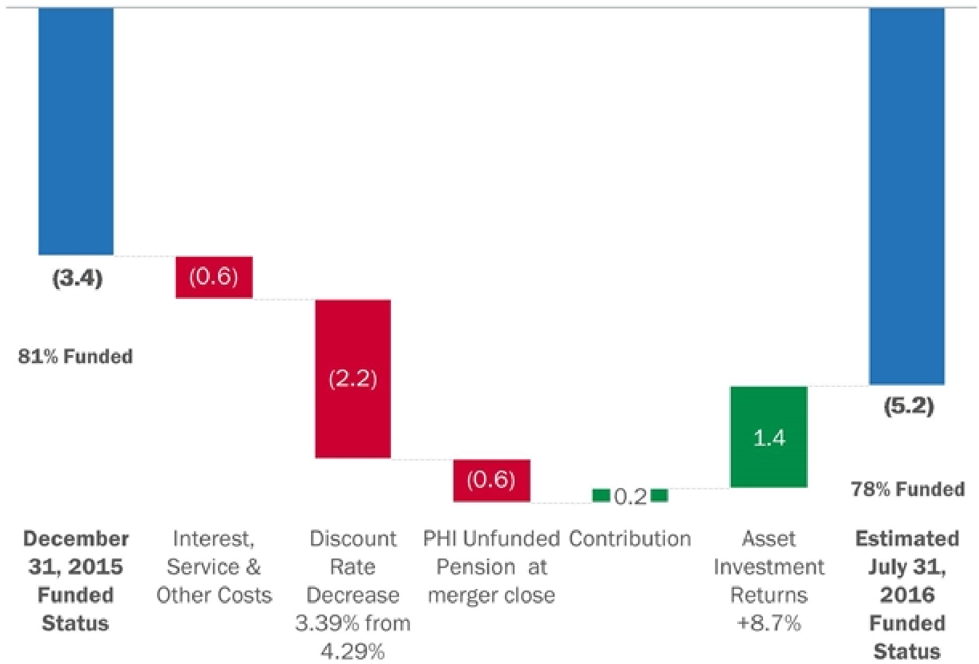


Exelon's weighted average LTD maturity is approximately 13 years

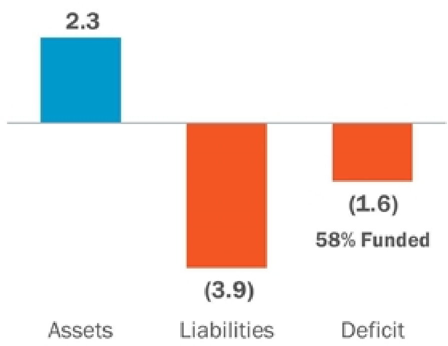
(1) ExCorp debt includes $1,150M mandatory convertible units remarketing in 2017; ExGen debt includes legacy CEG debt; Excludes securitized debt and non-recourse debt

Pension and OPEB – Funded Status and Performance

Pension Estimated July 31, 2016 Funded Status (PBO) Comparison ($B)



OPEB Funded Status December 31, 2015 ($B)



- Year to date investment returns of 8.7% or $1.4 billion have offset more than 60% of the pension liability increase due to lower discount rates
- Based on estimates from Goldman Sachs, the aggregate funded status for pension plans in S&P 500 companies is 78% funded at the end of July
- Exelon funded status for funding purposes (PPA) is significantly higher than PBO/GAAP funded status which results in no required material pension contributions over the LRP period

Exelon Pension Investment Approach

- **Investment Strategy**
  - Exelon has developed and implemented an actively managed liability hedging based investment strategy that has reduced the volatility of the pension assets relative to pension liabilities
  - The overall objective is to achieve attractive risk adjusted returns that will balance the liquidity requirements of the plan's liability while striving to minimize the risk of significant loss
  - The liability hedging strategy is expected to offset a significant portion of a liability increase due to lower interest rates
  - Year to date 2016, the hedging strategy has offset approximately 60% of the liability increase due to lower discount rates
- **Prudent Governance**
  - The general oversight of all Exelon investment activities including the pension fund is under the purview of the Investment Oversight Committee of the Exelon Board of Directors. The committee consists of members of the Exelon Board with substantial and lengthy investment experience and professional investment expertise
- **Investment Staff**
  - Exelon employs a very experienced and seasoned team of investment professionals to manage all of the company's benefit plan and nuclear decommissioning trust investments
- **Funding of Pension Liabilities**
  - Exelon maintains a consistent and prudent approach to pension funding
  - Annual pension contributions ($B)

Year	Contribution Amount
2010	$0.8
2011	$2.1
2012	$0.1
2013	$0.3

Year	Contribution Amount
2014	$0.3
2015	$0.5
2016	$0.3
Total	$4.4

Pension and OPEB Contributions and Expense

	2016 (1)		2017	
(in $M)	Pre-Tax Expense(2)	Contributions	Pre-Tax Expense(2)	Contributions
Qualified Pension (3) (4)(5)	$410	$310	$470	$310
Non-Qualified Pension	20	35	20	25
OPEB(4)(5)	5	50	30	55
Total	**$435**	**$395**	**$520**	**$390**

Decrease in discount rate drives ($0.02 - $0.04) of additional expense annually versus previous disclosure at Q4 2015

(1) PHI expense is included for the post-merger period (March 24 - December 31, 2016)
(2) Pension and OPEB expenses assume a 30% capitalization rate
(3) The Balanced Funding Strategy for the Qualified Plans provides pension funding of the greater of $250M or minimum required contributions plus amounts required to avoid benefit restrictions and at-risk status
(4) Expected return on assets for pension is 7.00% and for OPEB is 6.70%
(5) Pension and OPEB discount rates are 4.29% for legacy Exelon plans and ~4% for PHI for 2016. Estimated discount rates are ~3.55% and 3.85% for Exelon and PHI for 2017.

EPS Sensitivities

		2016	2017	2018	2019	Fully Open
ExGen EPS Impact[1]	Henry Hub Natural Gas					
	+$1/MMBtu	($0.02)	$0.08	$0.20	$0.33	$0.35
	-$1/MMBtu	$0.04	($0.07)	($0.19)	($0.31)	($0.33)
	NiHub ATC Energy Price					
	+$5/MWh	$0.01	$0.09	$0.17	$0.22	$0.24
	-$5/MWh	($0.01)	($0.09)	($0.17)	($0.22)	($0.24)
	PJM-W ATC Energy Price					
	+$5/MWh	($0.00)	$0.02	$0.08	$0.15	$0.18
	-$5/MWh	$0.00	($0.02)	($0.08)	($0.15)	($0.18)
	PJM Capacity Market					
	+$10/MW-day					$0.03
	-$10/MW-day					($0.03)
ComEd EPS Impact	**30 Year Treasury Rate**					
	+50 basis points		$0.02	$0.02	$0.02	
	-50 basis points		($0.02)	($0.02)	($0.02)	
	Share Count *(millions)*	926	948	967	970	

(1) Based on June 30, 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 price inputs constant. Due to correlation of the various assumptions, the EPS impact calculated by aggregating individual sensitivities may not be equal to the EPS impact calculated when correlations between the various assumptions are also considered. Represents adjusted (non-GAAP) operating earnings. Refer to slide 165 for a list of adjustments from GAAP EPS to adjusted (non-GAAP) operating earnings.

(2) Based on Planning Year 2019/2020 cleared Capacity Performance Volumes

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Exelon Utilities Adjusted Operating EPS Contribution(1)

Numbers may not add due to rounding.

Key Drivers – 2Q 2016(2) vs. 2Q 2015:

BGE (-0.02):

- Impairment charges resulting from certain disallowances contained in the June and July rate case orders: ($0.03)
- Increased transmission and distribution revenue: $0.01

PECO (+0.03):

- Increased electric distribution rates: $0.02
- Cumulative tax adjustment related to an anticipated gas repairs tax return accounting method change: $0.01

ComEd (+0.04):

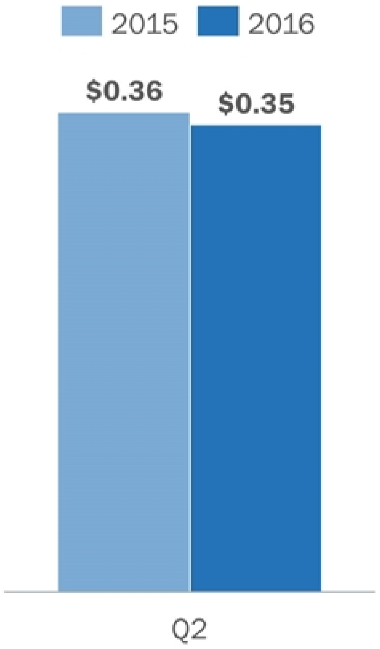
- Increased distribution and transmission earnings due to increased capital investment(3): $0.02
- Favorable weather(3): $0.02
- Decreased distribution earnings due to lower return on common equity(3): $(0.01)

PHI (+0.06):

- Reflects PHI actual results for the period of April 1, 2016 to June 30, 2016(4): $0.06

(1) Refer to slides 163 and 164 for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS
(2) There is a $(0.01) share differential impact spread across the utilities in Q2 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
(4) For the three months ended June 30, 2016, includes financial results for PHI. Therefore, the results of operations from 2016 and 2015 are not comparable for PHI and Exelon. PHI consolidated results includes Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company.

ExGen Adjusted Operating EPS Contribution[(1)]



Key Drivers – 2Q 2016 vs. 2Q 2015

ExGen (-0.01):

- Increased RNF primarily due to the approval of the Ginna Reliability Support Services Agreement for periods retroactive to April 1, 2015, partially offset by lower realized energy prices and increased nuclear outage days: $0.12
- Increased costs, which includes the impact of the timing and extended duration of an outage at the Salem nuclear power plant: $(0.05)
- Lower realized gains on NDT funds: $(0.03)
- Higher depreciation costs primarily due to increased nuclear decommissioning amortization: $(0.02)
- Share differential: $(0.03)

(excludes Salem)	Q2 2015 Actual	Q2 2016 Actual
Planned Refueling Outage Days	71	87
Non-refueling Outage Days	18	21
Nuclear Capacity Factor	93.1%	92.3%

Numbers may not add due to rounding

(1) Refer to slides 163 and 164 for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

Concluding Remarks

The Exelon Value Proposition

- **Regulated Utility Growth** with Utility EPS rising 7-9% annually from 2016-2020 and rate base growth of 6.1%, representing an expanding majority of earnings
- **ExGen's strong free cash generation** will support utility growth while also reducing debt by ~$3B over the next 5 years
- **Optimizing ExGen value by:**
  - Seeking fair compensation for the zero-carbon attributes of our fleet;
  - Closing uneconomic plants;
  - Monetizing assets; and,
  - Maximizing the value of the fleet through our generation to load matching strategy
- **Strong balance sheet is a priority** with all businesses comfortably meeting investment grade credit metrics through the 2020 planning horizon
- **Capital allocation priorities targeting**:
  - Organic utility growth;
  - Return of capital to shareholders with 2.5% annual dividend growth through 2018[1],
  - Debt reduction; and,
  - Modest contracted generation investments

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

Reconciliation of Non-GAAP Measures

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2Q QTD GAAP EPS Reconciliation

Three Months Ended June 30, 2015	ExGen	ComEd	PECO	BGE	Other	Exelon
2Q 2015 GAAP Earnings Per Share	**$0.46**	**$0.12**	**$0.08**	**$0.05**	**$0.04**	**$0.74**
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 swap	-	-	-	-	(0.08)	(0.08)
Amortization of commodity contract intangibles	0.01	-	-	-	-	0.01
Long-lived asset impairments	-	-	-	-	0.02	0.02
CENG Non-Controlling Interest	(0.02)	-	-	-	-	(0.02)
2015 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.36**	**$0.12**	**$0.08**	**$0.05**	**$(0.01)**	**$0.59**

Three Months Ended June 30, 2016	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2Q 2016 GAAP Earnings (Loss) Per Share	**$0.00**	**$0.16**	**$0.11**	**$0.03**	**$0.06**	**($0.06)**	**$0.29**
Mark-to-market impact of economic hedging activities	0.20	-	-	-	-	-	0.20
Unrealized gains related to NDT fund investments	(0.03)	-	-	-	-	-	(0.03)
Amortization of commodity contract intangibles	0.01	-	-	-	-		0.01
Long-lived asset impairments	0.02	-	-	-	-	-	0.02
Plant retirements and divestitures	0.14	-	-	-	-	-	0.14
Cost management program	-	-	-	-	-	-	0.01
CENG non-controlling interest	0.01	-	-	-	-	-	0.01
2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.35**	**$0.16**	**$0.11**	**$0.03**	**$0.06**	**$(0.06)**	**$0.65**

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, 2015	ExGen	ComEd	PECO	BGE	Other	Exelon
2Q 2015 GAAP Earnings (Loss) Per Share	**$0.97**	**$0.22**	**$0.24**	**$0.18**	**$(0.07)**	**$1.54**
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 swap	-	-	-	-	(0.03)	(0.03)
Amortization of commodity contract intangibles	(0.02)	-	-	-	-	(0.02)
Long-lived asset impairments	-	-	-	-	0.02	0.02
Midwest Generation bankruptcy recoveries	(0.01)	-	-	-	-	(0.01)
CENG Non-Controlling Interest	(0.01)	-	-	-	-	(0.01)
2015 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.71**	**$0.22**	**$0.24**	**$0.18**	**$(0.05)**	**$1.30**

Six Months Ended June 30, 2016	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2Q 2016 GAAP Earnings (Loss) Per Share	**$0.31**	**$0.28**	**$0.25**	**$0.14**	**$(0.28)**	**$(0.23)**	**$0.48**
Mark-to-market impact of economic hedging activities	0.12	-	-	-	-	-	0.12
Unrealized gains related to NDT fund investments	(0.07)	-	-	-	-	-	(0.07)
Merger and integration costs	0.02	-	-	-	0.04	0.04	0.09
Merger commitments	-	-	-	-	0.30	0.12	0.43
Long-lived asset impairments	0.10	-	-	-	-	-	0.10
Plant retirements and divestitures	0.14	-	-	-	-	-	0.14
Reassessment of state deferred income taxes	0.01	-	-	-	-	(0.01)	-
Cost management program	0.02	-	-	-	-	-	0.02
CENG non-controlling interest	0.02	-	-	-	-	-	0.02
2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.69**	**$0.28**	**$0.25**	**$0.14**	**$0.06**	**$(0.08)**	**$1.33**

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 Q2 2016 and forecasted 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
  - Impairments of upstream assets and certain wind projects
  - Plant retirements and divestitures at Generation
  - Non-cash impact of the remeasurement of state deferred income taxes, primarily as a result of PHI acquisition
  - Costs incurred related to cost management program
  - Generation's non-controlling interest related to CENG exclusion items
  - Other unusual items

GAAP to Non-GAAP Reconciliations

YE 2016 Exelon FFO Calculation ($M)[1,2]	
GAAP Operating Income	$2,100
Depreciation & Amortization	$3,650
EBITDA	$5,750
+/- Non-operating activities and nonrecurring items[4]	$825
- Interest Expense	($1,400)
+ Current Income Tax (Expense)/Benefit	$125
+ Nuclear Fuel Amortization	$1,175
+/- Other S&P FFO Adjustments[5]	$325
= FFO (a)	**$6,800**

YE 2016 Exelon Adjusted Debt Calculation ($M)[1]	
Long-Term Debt (including current maturities)	$33,050
Short-Term Debt	$2,150
+ PPA Imputed Debt[6]	$500
+ Operating Lease Imputed Debt[7]	$750
+ Pension/OPEB Imputed Debt[8]	$4,625
- Off-Credit Treatment of Debt[9]	($3,225)
- Surplus Cash Adjustment[10]	($625)
+/- Other S&P FFO Adjustments[5]	$325
= Adjusted Debt (b)	**$37,550**

YE 2016 Exelon FFO/Debt[3]		
FFO (a) / Adjusted Debt (b)	=	18%

(1) All amounts rounded to the nearest $25M
(2) 2016 estimate normalized to include a full year for PHI
(3) Calculated using S&P Methodology. Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment
(4) Reflects impact operating adjustments on GAAP EBITDA. Refer to slide 165 for a list of operating adjustments to GAAP.
(5) Includes other adjustments as prescribed by S&P
(6) Reflects present value of net capacity purchases
(7) Reflects present value of minimum future operating lease payments
(7) Reflects after-tax unfunded pension/opeb
(8) Includes non-recourse project debt and mandatory convertible equity units
(9) Applies 75% of excess cash against balance of LTD

GAAP to Non-GAAP Reconciliations

YE 2016 ExGen Net Debt Calculation ($M)[1]	
Long-Term Debt (including current maturities)	$10,150
Short-Term Debt	$950
- Surplus Cash Adjustment	($300)
= Net Debt (a)	**$10,800**

YE 2016 ExGen Operating EBITDA Calculation ($M)[1]	
GAAP Operating Income	$375
Depreciation & Amortization	$1,975
EBITDA	$2,350
+/- Non-operating activities and nonrecurring items[2]	$850
= Operating EBITDA (b)	**$3,200**

YE 2016 Debt / EBITDA

$$\frac{\text{Net Debt (a)}}{\text{Operating EBITDA (b)}} = 3.4x$$

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

(2) Reflects impact operating adjustments on GAAP EBITDA. Refer to slide 165 for a list of operating adjustments to GAAP.

GAAP to Non-GAAP Reconciliations

ExGen Adjusted O&M Reconciliation ($M)[1]	2016	2017	2018	2019	2020
GAAP O&M	**$5,625**	**$5,225**	**$5,050**	**$5,100**	**$5,150**
Decommissioning[2]	125	150	100	50	50
Costs associated with early nuclear plant retirements	(125)	-	-	-	-
Long-lived asset impairment costs	(150)	-	-	-	-
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses[3]	(425)	(375)	(375)	(400)	(425)
O&M for managed plants that are partially owned	(400)	(425)	(425)	(425)	(450)
Other	(125)	(25)	-	(25)	(25)
Adjusted O&M (Non-GAAP)	**$4,525**	**$4,550**	**$4,350**	**$4,300**	**$4,300**

2016-2020 ExGen Free Cash Flow Calculation ($M)[1]	
Cash from Operations (GAAP)	$17,975
Other Cash from Investing Activities	($600)
Baseline Capital Expenditures[4]	($4,625)
Nuclear Fuel Capital Expenditures	($4,525)
Free Cash Flow before Growth CapEx and Dividend	**$8,225**

(1) All amounts rounded to the nearest $25M
(2) Reflects earnings neutral O&M
(3) Reflects the direct cost of sales of certain Constellation and Power businesses of Generation, which are included in Total Gross Margin, a non-GAAP measure
(4) Baseline capital expenditures refer to maintenance and required capital expenditures necessary for day to day plant operations

GAAP to Non-GAAP Reconciliations

2016 Adjusted O&M Reconciliation ($M)[1]	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
GAAP O&M	**$5,625**	**$1,550**	**$875**	**$825**	**$1,500**	**$100**	**$10,475**
Regulatory O&M[2]	-	(225)	(75)	-	(100)	-	(400)
Decommissioning[2]	125	-	-	-	-	-	125
Costs associated with early nuclear plant retirements	(125)	-	-	-	-	-	(125)
Long-lived asset impairment costs	(150)	-	-	-	-	-	(150)
Merger commitments and costs to achieve	-	-	-	-	(425)	(175)	(600)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses[3]	(425)	-	-	-	-	-	(425)
O&M for managed plants that are partially owned	(400)	-	-	-	-	-	(400)
Other	(125)	(25)	(25)	(25)	-	-	(200)
Adjusted O&M (Non-GAAP)	**$4,525**	**$1,300**	**$775**	**$800**	**$975**	**$(75)**	**$8,300**

2020 Adjusted O&M Reconciliation ($M)[1]	ExGen	Utility/HoldCo	Exelon
GAAP O&M	**$5,150**	**$4,175**	**$9,325**
Regulatory O&M[2]	-	(525)	(525)
Decommissioning[2]	50	-	50
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses[3]	(425)	-	(425)
O&M for managed plants that are partially owned	(450)	-	(450)
Other	(25)	-	(25)
Adjusted O&M (Non-GAAP)	**$4,300**	**$3,650**	**$7,950**

(1) All amounts rounded to the nearest $25M
(2) Reflects earnings neutral O&M
(3) Reflects the direct cost of sales of certain Constellation and Power businesses of Generation, which are included in Total Gross Margin

Exelon.

GAAP to Non-GAAP Reconciliations

2016 Adjusted Cash from Ops Calculation ($M)(1)	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
Net cash flows provided by operating activities (GAAP)	$1,700	$750	$600	$800	$4,000	($400)	$7,425
Other cash from investing activities	-	-	-	($25)	($125)	-	($150)
Intercompany receivable adjustment	($200)	-	-	-	-	$200	-
Counterparty collateral activity	-	-	-	-	($275)		($275)
Adjusted Cash Flow from Operations	**$1,500**	**$750**	**$600**	**$775**	**$3,600**	**($200)**	**$7,000**

2016 Cash From Financing Calculation ($M)(1)	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	$800	($250)	$250	$450	($375)	$1,775	$2,650
Dividends paid on common stock	$375	$275	$175	$175	$1,125	($950)	$1,175
Intercompany receivable adjustment	$200	-	-	-	-	($200)	
Purchase of PHI (including cash acquired)	-	-	-	-	-	($6,925)	($6,925)
Financing Cash Flow	**$1,375**	**$25**	**$425**	**$625**	**$750**	**($6,300)**	**($3,100)**

Exelon Total Cash Flow Reconciliation(1)	2016
GAAP Beginning Cash Balance	**$6,500**
Adjustment for Cash Collateral Posted	$1,300
Adjusted Beginning Cash Balance(3)	$7,800
Net Change in Cash (GAAP)(2)	$(6,275)
Adjusted Ending Cash Balance(3)	$1,525
Adjustment for Cash Collateral Posted	($1,000)
GAAP Ending Cash Balance	**$525**

(1) All amounts rounded to the nearest $25M. Items may not sum due to rounding.
(2) Represents the GAAP measure of net change in cash, which is the sum of cash flow from operations, cash from investing activities, and cash from financing activities. Figures reflect cash capital expenditures and CENG fleet at 100%.
(3) Adjusted Beginning and Ending cash balances reflect GAAP Beginning and End Cash Balances excluding counterparty collateral activity

GAAP to Non-GAAP Reconciliations

BGE Operating ROE Reconciliation	2011	2012	2013	2014	2015
Net Income (GAAP)	$123	($9)	$197	$198	$275
Operating exclusions[1]	$18	$96	($2)	$1	$3
Adjusted Operating Earnings	$141	$87	$195	$199	$278
Average Equity	$2,092	$2,139	$2,266	$2,464	$2,625
Operating ROE (Adjusted Operating Earnings/Average Equity)	**6.7%**	**4.1%**	**8.6%**	**8.1%**	**10.6%**

(1) Operating exclusions represent adjustments for merger commitments and costs to achieve