

Edison Electric Institute Financial Conference

November 11 – 12, 2013



Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company and Exelon Generation Company, LLC (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2012 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 19; (2) Exelon's Third Quarter 2013 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 (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this presentation. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

Setting the Context

The current trends in the industry...

- Increasing natural gas production
- Expanding renewable capacity
- Growing demand response and energy efficiency

... are continuing to create a challenging environment...

- Low natural gas and power prices
- Low load growth
- Lack of volatility

... and Exelon is responding...

- Asset optimization and rationalization
- Leverage business model to identify and invest in growth areas
- Manage costs and improve efficiencies
- Advocate for policies that enable well-functioning competitive markets and create value for shareholders

...while monitoring the power markets for recovery.

- Full impact of coal retirements is not currently reflected in the forward markets
- Significant number of coal plants need additional controls to comply with MATS
- Forward market implied heat rates are trading at a discount to the spot market
- Upside in both forward and spot markets as current heat rates move higher

While we believe in market recovery, we are not waiting for it and are taking actions to improve our value

Exelon's Strategic Response to the Current Environment

Asset Optimization

Review Solutions from All Angles

- Infrastructure
- Commercial
- Policy
- Legal

Scenarios for Optimization

- Cost and productivity enhancement
- Operations improvement
- Transmission
- PPAs
- Sale
- Retirement

Growth Investments

Utilities

- Invest \$15 billion across the planning period
- Upgrade aging infrastructure
- Invest in infrastructure and new technologies
- Provide stable earnings growth

ExGen

- Invest in renewables and expand footprint in the natural gas business to diversify
- Maintain retail pricing discipline
- Bolster presence in core regions
- Research and invest in emerging technologies

Cost Management

Our Record

- Record of managing costs
- \$550 million in merger synergies
- Reduced 2013 ExGen O&M by \$150 million
- CENG annual projected synergies of \$50-70 million⁽¹⁾

Continued Focus

- Expand cost management efforts
- Efficiency gains through productivity and technology enhancements
- Share best practices across the utilities

We are biased towards action while we leverage our competencies and strengths to influence our financial future

(1) At 100% ownership, Exelon share is 50%

Advocating for Public Policy to Enhance Customer and Shareholder Value

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PUBLIC

Regulatory / Policy Actions

Market Policy

PJM:

- Engaged in stakeholder process regarding PJM reliance on planned resources
- Minimum Offer Price Rule (MOPR) Reform
- Demand Response Reforms

ERCOT:

- Resource adequacy

New England:

- Energy and capacity market reforms

RGGI:

- New Model Rule

Federal Policy

Subsidies:

- Leading voice against extension of the Production Tax Credit and other electric generation subsidies

EPA Regulations:

- Mercury and Air Toxics Standards (MATS)
- Greenhouse gases (new and existing sources)
- 316(b)

State Policy

Oppose Subsidized Generation:

- IL: Defeated Taylorsville Energy Project Subsidy legislation
- MA: Opposed Footprint Power Subsidy legislation
- NJ: Won LCAPP Court decision

Infrastructure & Ratemaking Improvements:

- IL: Energy Infrastructure and Modernization Legislation (Senate Bill 9)
- MD/PA: Policies to speed recovery for gas and infrastructure investments

Investing in a Stronger Future

Core Strength

Strategic Focus and Actions

Strong Balance Sheet



Solid financial footing and investment grade credit rating will allow us to grow in challenging times.

Utility Investment



Significant infrastructure and technology enhancements under regulatory structures that allow a fair rate of return.

Operating Excellence



Generating fleet will continue unwavering focus on world class performance.

Asset Optimization



Disciplined fleet evaluation will drive strategic decisions to unlock value, improve cash flow and grow earnings.

Portfolio Management



Enhance the value of our portfolio through implementation of our fundamental view and disciplined retail pricing.

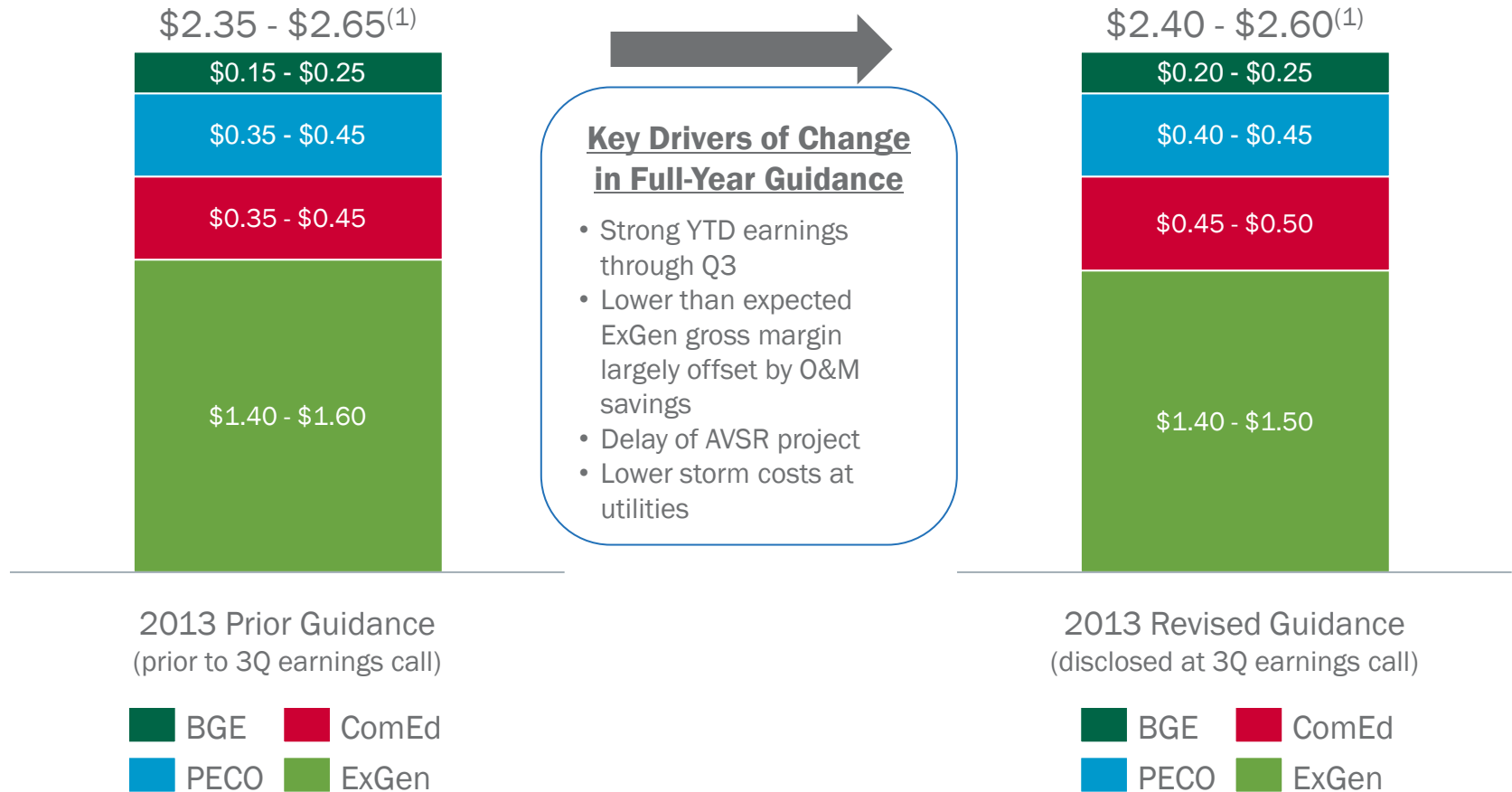
Well-Crafted Public Policies



Advocate for policies that strengthen competitive markets, limit subsidies and enhance the value of clean generation.

Financial Update

2013 Operating Earnings Guidance

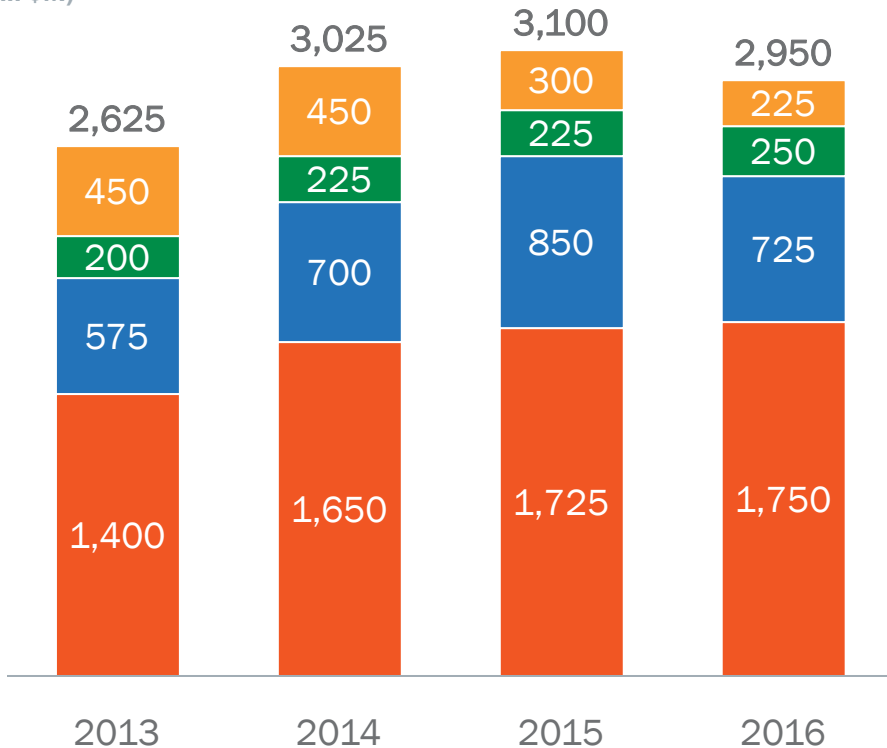


(1) Earnings guidance for OpCos may not add up to consolidated EPS guidance. Refer to slide 15 for a list of adjustments from GAAP EPS to adjusted (non-GAAP) operating EPS.

Capital Expenditure Expectations

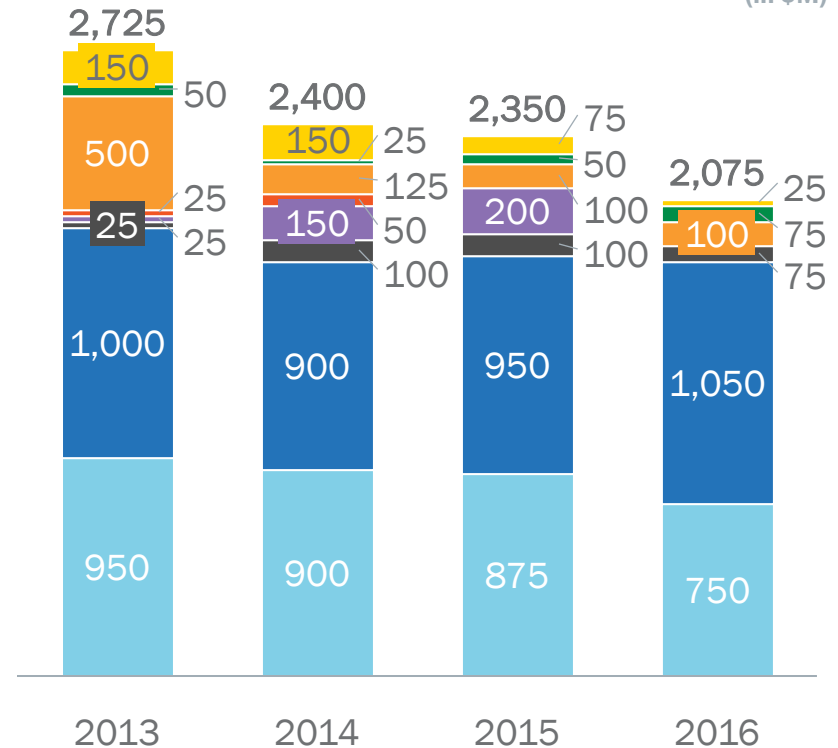
Exelon Utilities

(in \$M)



Exelon Generation⁽¹⁾

(in \$M)



■ Smart Grid/Smart Meter ■ Electric Transmission
■ Gas Delivery ■ Electric Distribution

■ Nuclear Upgrades ■ MD Commitments
■ Upstream Gas ■ Fukushima Response⁽²⁾
■ Solar ■ Nuclear Fuel
■ Wind ■ Base Capex

(1) Excludes CENG

(2) Fukushima Response spend excludes Salem, which is included in Base CapEx

2013 Projected Sources and Uses of Cash

(\$ in millions)	BGE	ComEd	PECO	ExGen	Exelon ⁽⁶⁾	As of 2Q13	Delta
Beginning Cash Balance⁽¹⁾					1,575	1,575	--
Cash Flow from Operations ⁽²⁾	575	1,075	650	3,550	5,775	5,550	225
CapEx (excluding other items below):	(500)	(1,300)	(375)	(1,000)	(3,275)	(3,300)	25
Nuclear Fuel	n/a	n/a	n/a	(1,000)	(1,000)	(1,000)	–
Dividend ⁽³⁾					(1,250)	(1,250)	–
Nuclear Upgrades	n/a	n/a	n/a	(150)	(150)	(150)	–
Wind	n/a	n/a	n/a	(25)	(25)	(25)	–
Solar	n/a	n/a	n/a	(500)	(500)	(550)	50
Upstream	n/a	n/a	n/a	(50)	(50)	(50)	–
Utility Smart Grid/Smart Meter	(125)	(150)	(175)	n/a	(450)	(450)	–
Net Financing (excluding Dividend):							
Debt Issuances	300	350	550	–	1,200	1,200	–
Debt Retirements ⁽⁴⁾	(400)	(250)	(500)	(450)	(1,600)	(1,600)	–
Project Finance/Federal Financing Bank Loan	n/a	n/a	n/a	850	850	1,025	(175)
Other ⁽⁵⁾	75	350	(75)	(125)	325	300	25
Ending Cash Balance⁽¹⁾					1,425	1,275	150

(1) Exelon beginning cash balance as of 1/1/13. Excludes counterparty collateral activity.

(2) Cash Flow from Operations primarily includes net cash flows provided by operating activities and net cash flows used in investing activities other than capital expenditures.

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

(4) Includes PECO's \$210 million Accounts Receivable (A/R) Agreement with Bank of Tokyo and excludes BGE's current portion of its rate stabilization bonds

(5) "Other" includes proceeds from options, redemption of PECO preferred stock and expected changes in short-term debt, including money pool activity.

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

Commitment to Investment Grade

Value of Investment Grade

- Maintain key credit metrics above target ranges under both market and stress conditions to maintain investment grade ratings
- Shareholder value of maintaining investment grade:
 - Increases ability to participate in commercial business opportunities
 - Lowers collateral requirements
 - Reliable and cost efficient access to the capital markets
 - Increases business and financial flexibility

Current Ratings & Targets

Current Ratings ^{(1) (2)}

	Moody's	S&P	Fitch
Corp	Baa2	BBB-	BBB+
ComEd	A3	A-	BBB+
PECO	A1	A-	A
BGE	Baa1	A-	BBB+
Generation	Baa1	BBB	BBB+

Credit Metric Targets Supportive of Mid-High BBB/Baa Ratings ⁽³⁾

- FFO/Debt > 30% in base case and 27% in stress case
- RCF/Debt > 20%
- Positive Moody's FCF

- (1) Current senior unsecured ratings for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd and PECO as of September 25, 2013.
- (2) All ratings at S&P and Moody's have a stable outlook. On August 23rd, BGE was upgraded one notch to A- as part of S&P's annual review. All other entities were affirmed. Additionally, on February 8th, Fitch affirmed all ratings for Exelon and subs and placed ComEd on positive outlook.
- (3) Credit metric target ranges are for ExGen and include the debt obligations of Exelon Corp.

Exelon remains committed to maintaining investment grade ratings

Pension and OPEB Forecast

Current Forecast:

- The table below provides the combined company's forecasted 2014 and 2015 pension and OPEB expense and contributions

	2014		2015	
(in \$M)	Pre-Tax Expense ⁽¹⁾	Contributions ⁽²⁾	Pre-Tax Expense ⁽¹⁾	Contributions ⁽²⁾
Pension ⁽³⁾⁽⁴⁾	\$335	\$275	\$315	\$175
OPEB ⁽³⁾⁽⁴⁾	\$165	\$210	\$160	\$200
Total	\$500	\$485	\$475	\$375

(1) Pension and OPEB expenses assume an ~ 25% capitalization rate.

(2) Contributions shown in the table above are based on the current contribution policy for the plans and include both amounts contributed to trusts and paid from corporate assets.

(3) Expected return on assets for pension is 7.00% and for OPEB is 6.45% (2014 and 2015). Amounts above assume an actual return on assets for pension and OPEB in 2013 of 4.88% and 8.00%, respectively.

(4) Projected 12/31/13 pension and OPEB discount rates are 4.80% and 4.92%, respectively.

2014 Pension and OPEB Sensitivities

- Tables below provide sensitivities for the combined company's 2014 pension and OPEB expense and contributions⁽¹⁾ under various discount rate and S&P 500 asset return scenarios

2014 Pension Sensitivity ⁽²⁾ (in \$M)						
S&P Returns in Q4 2013 ⁽³⁾						
10%		0%		-10%		
Discount Rate at 12/31/13	Pre-Tax Expense ⁽¹⁾	Contributions ⁽²⁾	Pre-Tax Expense ⁽¹⁾	Contributions ⁽²⁾	Pre-Tax Expense ⁽¹⁾	Contributions ⁽²⁾
Baseline Discount Rate ⁽⁴⁾	\$325	\$275	\$335	\$275	\$350	\$275
+50 bps	\$295	\$25	\$300	\$275	\$315	\$275
- 50bps	\$365	\$275	\$380	\$275	\$390	\$275

2014 OPEB Sensitivity ⁽²⁾ (in \$M)						
S&P Returns in Q4 2013 ⁽³⁾						
10%		0%		-10%		
Discount Rate at 12/31/13	Pre-Tax Expense ⁽¹⁾	Contributions ⁽²⁾	Pre-Tax Expense ⁽¹⁾	Contributions ⁽²⁾	Pre-Tax Expense ⁽¹⁾	Contributions ⁽²⁾
Baseline Discount Rate ⁽⁴⁾	\$155	\$195	\$165	\$210	\$180	\$225
+50 bps	\$135	\$180	\$150	\$185	\$160	\$200
- 50bps	\$180	\$220	\$190	\$235	\$200	\$250

(1) Contributions shown in the table above are based on the current contribution policy and include the impact of pension funding relief.

(2) Pension and OPEB expenses assume an ~ 25% capitalization rate in 2014.

(3) Final 2013 asset return for pension and OPEB will depend in part on overall equity market returns for Q4 2013 as proxied by the S&P 500. The amounts above reflect YTD S&P returns through September 30, 2013.

(4) The baseline discount rates reflect projected 12/31/13 pension and OPEB discount rates of 4.80% and 4.92%, respectively.

Additional 2013 ExGen and CENG Modeling

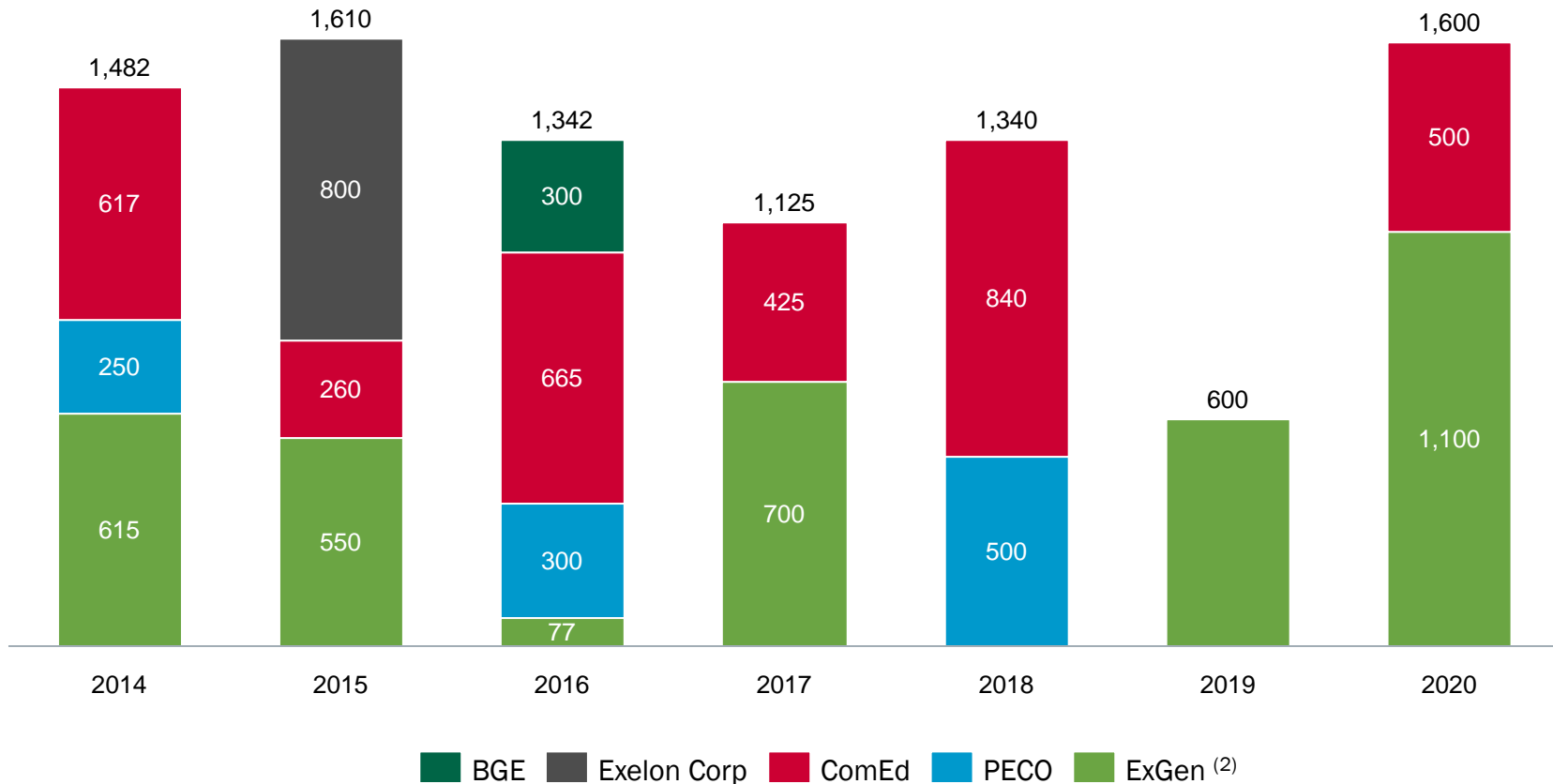
P&L Item	2013 Estimate
ExGen Model Inputs⁽¹⁾	
O&M ⁽²⁾	\$4,275M
Taxes Other Than Income (TOTI) ⁽³⁾	\$300M
Depreciation & Amortization ⁽⁴⁾	\$825M
Interest Expense	\$350M
CENG Model Inputs (at ownership)⁽⁵⁾	
Gross Margin	Included in ExGen Disclosures
O&M/TOTI	\$400M - \$450M
Depreciation & Amortization/Accretion of Asset Retirement Obligations	\$100M - \$150M
Capital Expenditures	\$75M - \$125M
Nuclear Fuel Capital Expenditure	\$100M - \$150M

- (1) ExGen amounts for O&M, TOTI and Depreciation & Amortization exclude the impacts of CENG. CENG impact is reflected in "Equity earnings of unconsolidated affiliates" in the Income Statement.
- (2) ExGen O&M excludes P&L neutral decommissioning costs and the impact from O&M related to entities consolidated solely as a result of the application of FIN 46R.
- (3) TOTI excludes gross receipts tax for retail.
- (4) ExGen Depreciation & Amortization excludes the impact of P&L neutral decommissioning.
- (5) The CENG model inputs are intended to support Exelon's guidance range and do not represent CENG's final estimates.

Debt Maturity Schedule

Debt Maturity Profile⁽¹⁾ (2014-2020)

(in \$M)



(1) As of 9/30/13

(2) Includes \$550M in 2015 and 2020 of inter-company loan agreements between Exelon and Exelon Generation that mirror the terms and amounts of the third party obligations of Exelon.

GAAP to Operating Adjustments

- **Exelon's 2013 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
 - Financial impacts associated with the sale or retirement of generating stations
 - Financial impacts associated with the increase in certain decommissioning obligations for spent nuclear fuel at retired nuclear units and increased retirement obligations for retired fossil power plants
 - Certain costs incurred associated with the Constellation merger and integration initiatives
 - Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at the merger date
 - Non-cash amortization of certain debt recorded at fair value at the merger date, which was retired in the second quarter of 2013
 - Non-cash charge to earnings resulting from the remeasurement of Exelon's like-kind exchange tax position
 - Non-cash charge to earnings related to the cancellation of previously capitalized nuclear uprate projects and the impairment of certain wind generating assets
 - Other unusual items

Exelon Utilities

ComEd April 2013 Distribution Formula Rate Updated Filing

The 2013 distribution formula rate filing establishes the net revenue requirement used to set the rates that will take effect in January 2014 after the ICC's review. The filing was updated to reflect the impact of Senate Bill 9. There are two components to the annual distribution formula rate filing:

- **Filing Year:** Based on prior year costs (2012) and current year (2013) projected plant additions.
- **Annual Reconciliation:** For the prior calendar year (2012), this amount reconciles the revenue requirement reflected in rates during the prior year (2012) in effect to the actual costs for that year. The annual reconciliation impacts cash flow in the following year (2014) but the earnings impact has been recorded in the prior year (2012) as a regulatory asset.

Docket #	13-0318
Filing Year	2012 Calendar Year Actual Costs and 2013 Projected Net Plant Additions are used to set the rates for calendar year 2014. Rates currently in effect (docket 13-0386) for calendar year 2013 were based on 2011 actual costs and 2012 projected net plant additions and reflect the impacts of PA 98-0015 (SB9).
Reconciliation Year	Reconciles Revenue Requirement reflected in rates during 2012 to 2012 Actual Costs Incurred. Revenue requirement for 2012 is based on dockets 10-0467, 11-0721 May Order and 11-0721 October Re-hearing Order.
Common Equity Ratio	~ 45% for both the filing and reconciliation year
ROE	8.72% for both the filing and reconciliation year (2012 30-yr Treasury Yield of 2.92% + 580 basis point risk premium). For 2013 and 2014, 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.
Requested Rate of Return	~ 7% for the both the filing and reconciliation year
Rate Base	\$6,702 million – Filing year (represents projected year-end rate base using 2012 actual plus 2013 projected capital additions). 2013 and 2014 earnings will reflect 2013 and 2014 year-end rate base respectively. \$6,389 million - Reconciliation year (represents year-end rate base for 2012)
Revenue Requirement Increase ⁽¹⁾	\$353M (\$191M is due to the 2012 reconciliation, \$162M relates to the filing year). The 2012 reconciliation impact on net income was recorded in 2012 as a regulatory asset. This increase also reflects the decrease in 2013 rates as a result of Senate Bill 9.
Timeline	<ul style="list-style-type: none"> • 04/29/13 Filing Date • 240 Day Proceeding • ICC order by year end; rates effective January 2014

Given the retroactive ratemaking provision in the 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.

BGE Rate Case

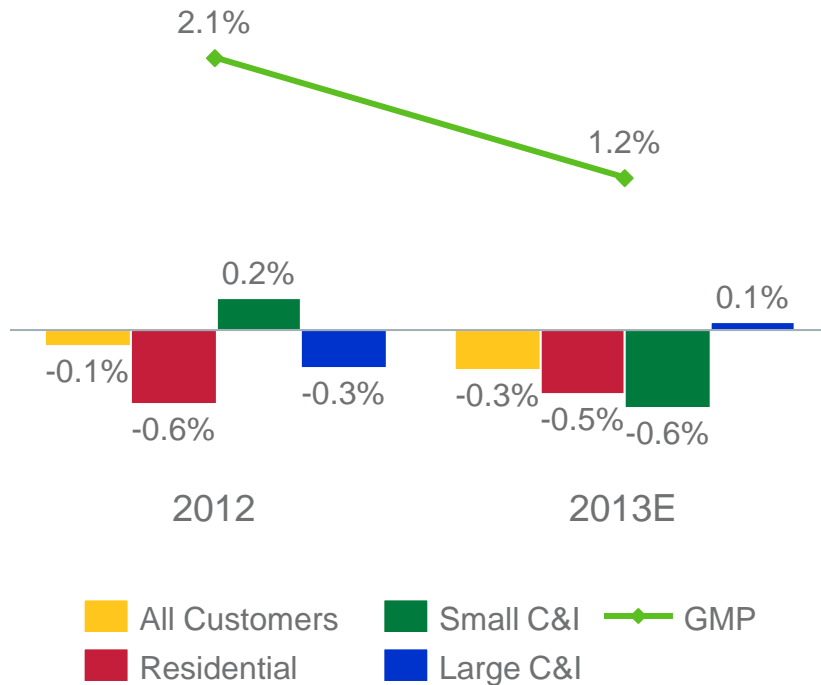
Rate Case Request	Electric	Gas
Docket #	9326	
Test Year	August 2012 – July 2013	
Common Equity Ratio	51.1%	
Requested Returns	ROE: 10.5%; ROR: 7.87%	ROE: 10.35%; ROR: 7.79%
Rate Base	\$2.8B	\$1.0B
Revenue Requirement Increase	\$82.6M	\$24.4M
Proposed Distribution Price Increase as % of overall bill	2%	3%

Timeline

- 5/17/13: BGE filed application with the MDPSC seeking increases in gas & electric distribution base rates
- 8/5/13: Staff/Intervenors file direct testimony
- 8/23/13: Update 8 months actual/4 month estimated test period data with actuals for last 4 months (March - July 2013)
- 9/17/13: BGE and staff/intervenors file rebuttal testimony
- 10/3/13: Staff/Intervenors and BGE file surrebuttal testimony
- 10/18/13 – 10/29/13: Hearings
- 11/12/13: Initial Briefs
- 11/22/13: Reply Briefs
- 12/13/13: Final Order
- New rates are in effect shortly after the final order

ComEd Load

Weather-Normalized Load YoY Growth



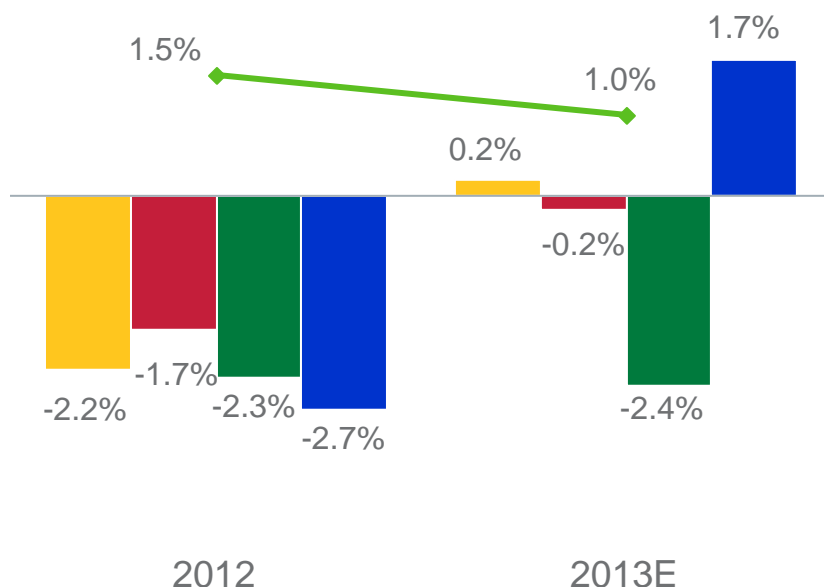
Economic Forecast of Drivers that Influence Load

Driver or Indicator	2014 Outlook
Gross Metro Product (GMP)	2.2% growth in GMP reflects overall better economic conditions than the slow growth in 2013 (Manufacturing and Professional Business Services employment accelerate in 2014)
Employment	1.4% increase in total employment is expected for 2014, which is consistent with the past three years
Manufacturing	Manufacturing employment is expected to grow 1.4% in 2014. This is a significant improvement over the 0.7% growth in 2012 and the 0.4% growth in 2013
Households	Household formations are expected to increase 0.4% in 2014. This is a slight improvement over the 0.3% realized in the past couple of years
Energy Efficiency	Continued expansion of EE program expected to reduce usage in 2014 by approximately 1.2%

Moderate growth economy and energy efficiency initiatives will continue to impact load growth

Notes: 2012 data is not adjusted for leap year. Source of 2014 economic outlook data is Global Insight (July 2013).

Weather-Normalized Load YoY Growth



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

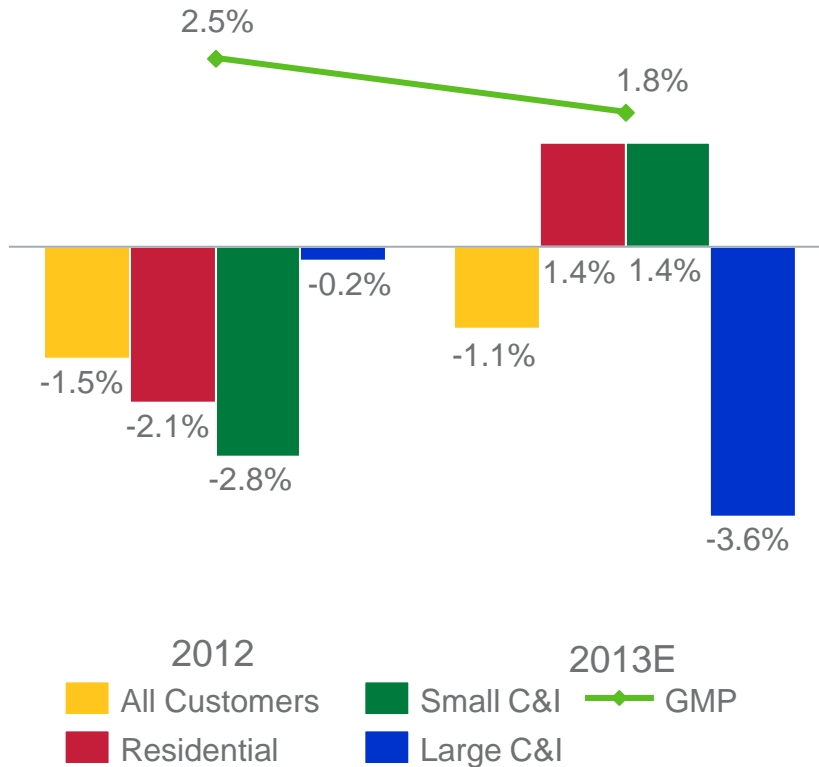
Economic Forecast of Drivers that Influence Load

Driver or Indicator	2014 Outlook
Gross Metro Product (GMP)	GMP projected to grow at 2.1% for 2014, vs. pre-recession average of 2.5%
Resident Employment	Resident Employment outlook is 1.0% in 2014 vs. 0.8% in 2013
Manufacturing Employment	Manufacturing employment is expected to grow at 1.1%. Philadelphia has had negative growth from 2000 to 2013
Households	Household growth is expected to be 0.7%, strongest growth since 2010
Energy Efficiency	Deemed Energy Efficiency impact forecasted to be ~1% reduction in usage in 2014

Moderately strong economic recovery will drive sales in 2014, but this will be partially offset by on-going energy efficiency initiatives

Notes: 2012 data is not adjusted for leap year. Source of 2013 economic outlook data is Global Insight (August 2013)

Weather-Normalized Load YoY Growth

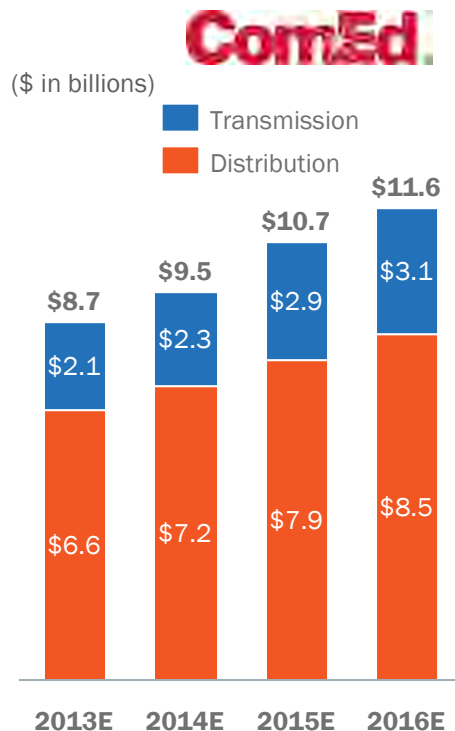


Economic Forecast of Drivers that Influence Load

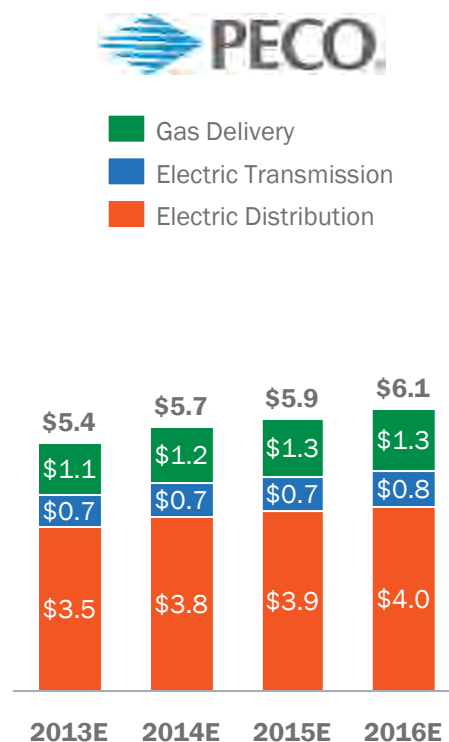
Driver or Indicator	2014 Outlook
Gross Metro Product (GMP)	GMP is projected to grow at 2.4% for 2014.
Employment	1.4% growth projected. BGE's decoupled non-rate case revenue growth is primarily driven by customer growth. The main driver for customer growth is employment.
Manufacturing	Manufacturing employment is expected to be fairly flat to 2013 levels in 2014
Households	Household growth is projected to be 0.9%, the same as 2013.
Energy Efficiency	Continued expansion of EE programs will partially offset growth seen due to improvements in economic conditions.

2014 is expected to be another transition year for the Baltimore economy with continued slow to moderate growth

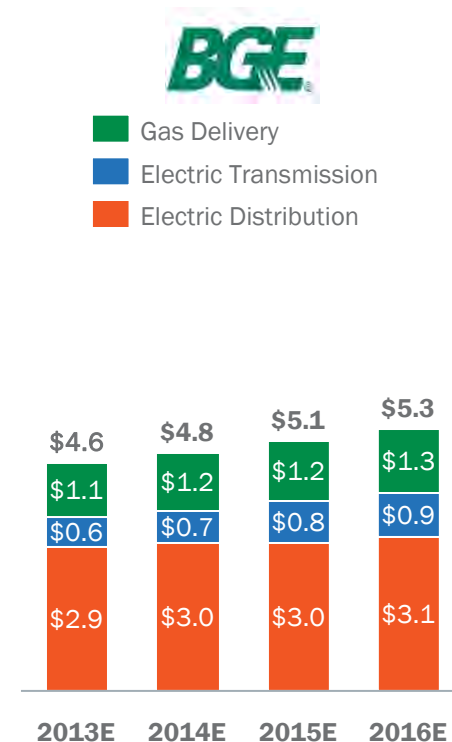
Exelon Utilities: Rate Base⁽¹⁾ and ROE Targets



	2013E	Long-Term Target
Equity Ratio	~45%	~53% ⁽²⁾
Earned ROE	8 -9%	Based on 30-yr. US Treasury ⁽³⁾



	2013E	Long-Term Target
Equity Ratio	~56%	~53%
Earned ROE	11.5 - 12.5%	≥10%



	2013E	Long-Term Target
Equity Ratio	~49%	~53% ⁽⁴⁾
Earned ROE	8.0-8.5%	≥10%

Continued investment in Utilities will provide stable earnings growth

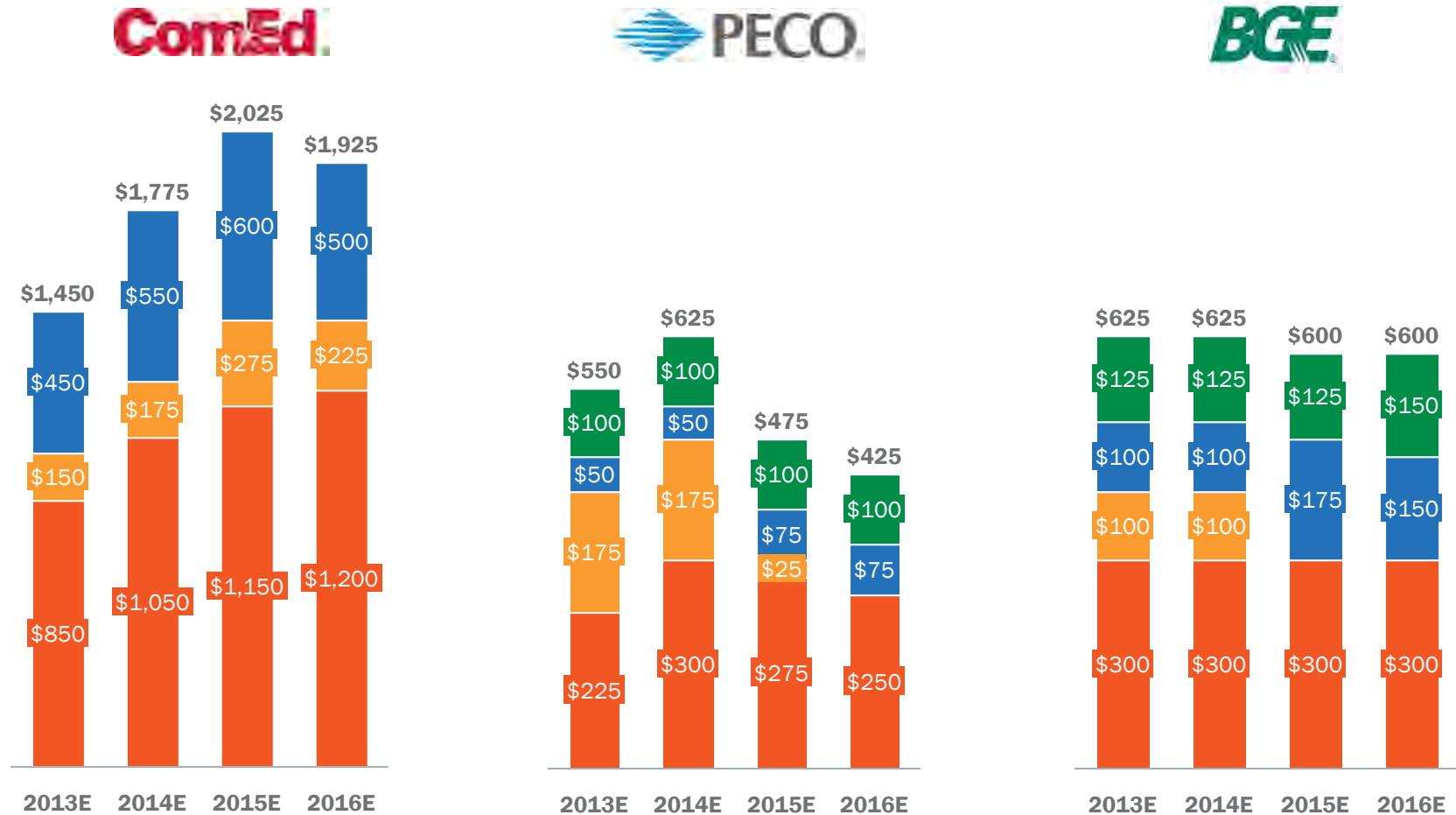
- (1) ComEd and PECO rate base represents end-of-year; and BGE rate base represents a trailing 13-month average. Numbers may not add due to rounding.
- (2) Equity component for distribution rates will be the actual capital structure adjusted for goodwill.
- (3) Earned ROE will reflect the weighted average of 11.5% allowed transmission ROE and distribution ROE resulting from 30-year Treasury plus 580 basis points for each calendar year.

- (4) Per MDPSC merger commitment, BGE is precluded from paying dividends through 2014. Per MDPSC orders, BGE cannot pay out a dividend to its parent company if said dividend would cause BGE's equity ratio to fall below 48%.

Capital Expenditures

(\$ in millions)

■ Gas Delivery
 ■ Electric Transmission
 ■ Smart Meter/Smart Grid⁽¹⁾
■ Electric Distribution



(1) Smart Meter/Smart Grid CapEx net of proceeds from U.S. Department of Energy (DOE) grant. For BGE, includes CapEx from Smart Energy Savers program of ~\$10M per year.

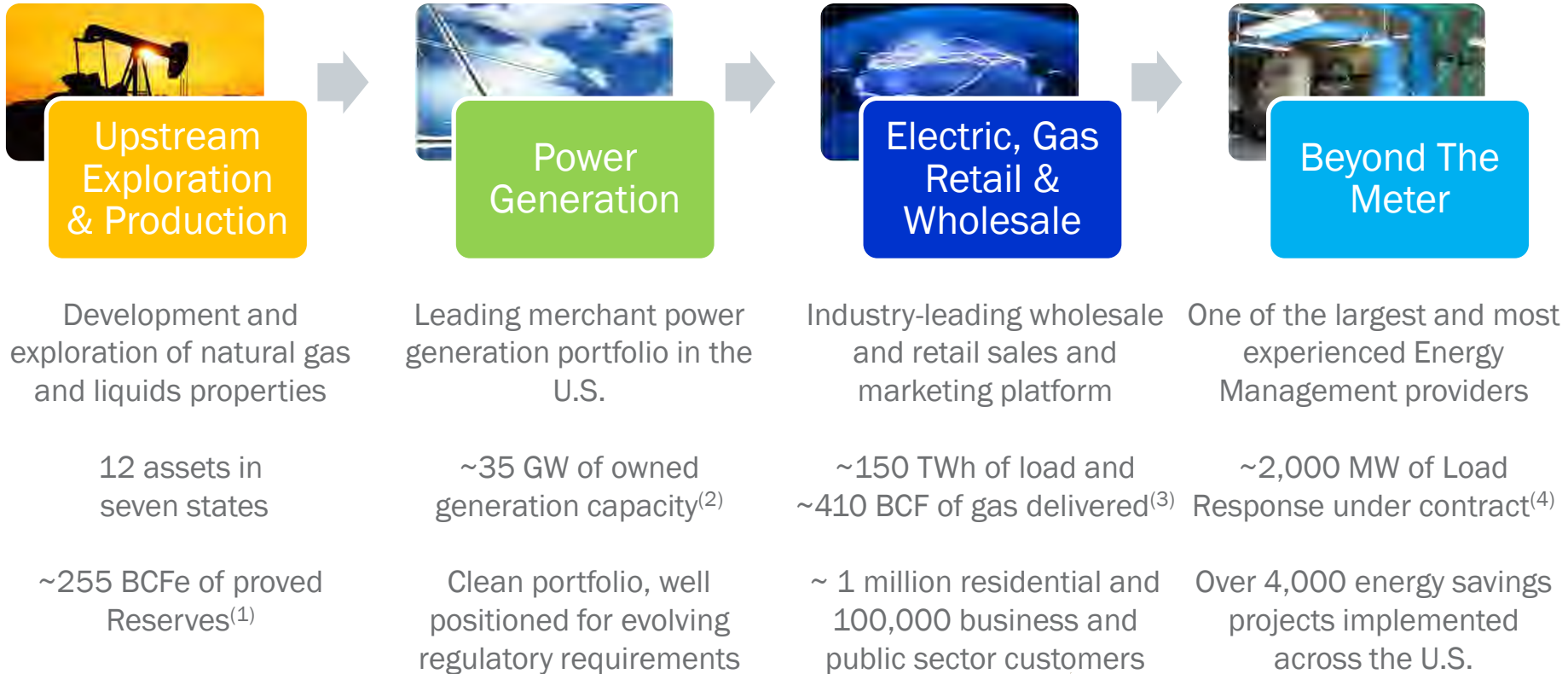
Regulatory Schedule

	4Q13	1Q14	2Q14	3Q14	4Q14
ComEd Distribution Formula Rate	13-0318 final order (by 12/25); rates effective 1/2/14 – 12/31/14		2014 formula rate case filing (by 5/15/14)		2014 formula rate case filing final order (by 12/31/14); rates effective 1/2/15 – 12/31/15
Illinois Power Agency Procurement		IPA proposed procurement events in April and September			
ComEd Transmission Rate Update			2014 formula rate case filing (by 5/15/14); rates effective June 2014 thru May 2015		
PECO Supply Procurement		DSP II Procurement (January)			DSP II Procurement (September)
PECO Distribution Filing		Potential Electric and Gas DSIC Filing			
BGE Distribution Rates	MDPSC Order expected December 13, 2013				
BGE Transmission Rate Update			2014 formula rate case filing (by 5/15/14); rates effective June 2014 thru May 2015		
BGE Supply Procurement	Regular procurement event (October)	Regular procurement event (January)	Regular procurement event (April and June)		Regular procurement event (October)



Commercial Business Overview

Scale, Scope and Flexibility Across the Energy Value Chain



Benefiting from scale, scope and flexibility across the value chain

(1) Estimated proved reserves as of 12/31/2012. Includes Natural Gas (NG), NG Liquids (NGL) and Oil. NGL and Oil are converted to BCFe at a ratio of 6:1.

(2) Total owned generation capacity as of 9/30/2013.

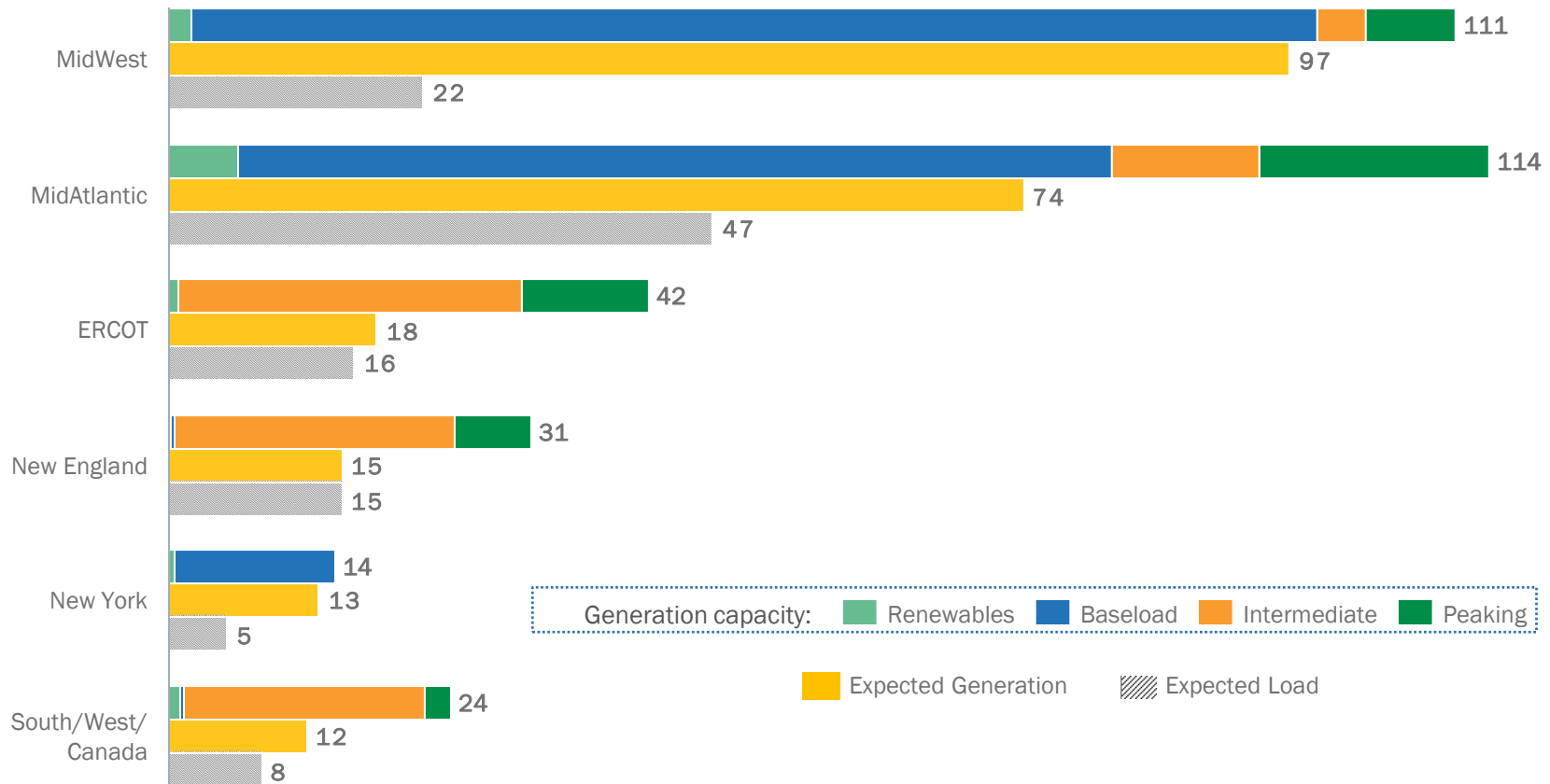
(3) Expected for 2013 as of 9/30/2013. Electric load and gas includes fixed price and indexed products.

(4) Load Response estimate as of 9/30/2013.

Generation and Load Match

Generation Capacity, Expected Generation and Expected Load

2014 in TWh ^(1,2)



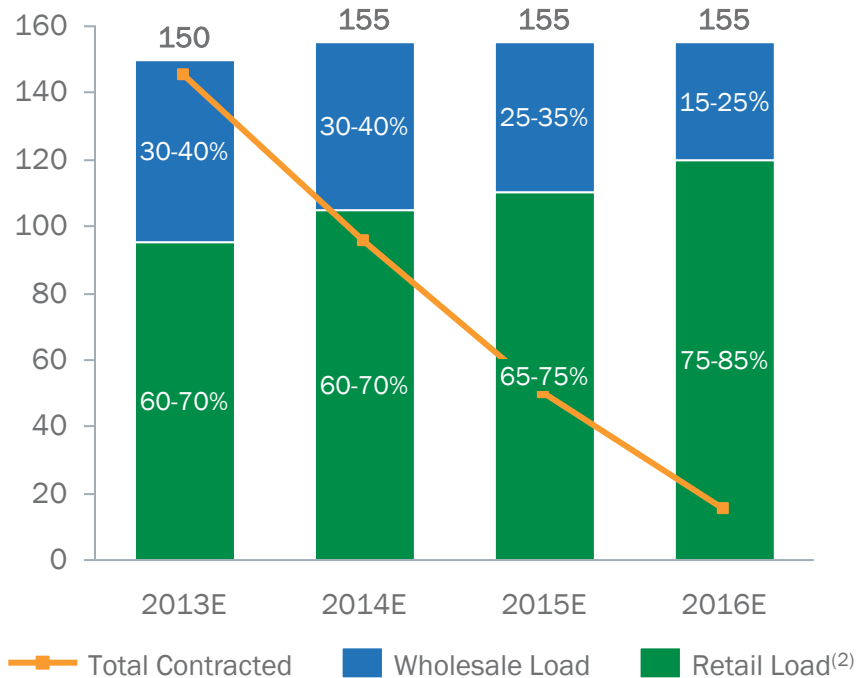
The combination establishes an industry-leading platform with regional diversification of the generation fleet and customer-facing load business

- (1) Owned and contracted generation capacity converted from MW to MWh assuming 100% capacity factor for all technology types, except for renewable capacity which is shown at estimated capacity factor.
 (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 9/30/2013.

Electric Load Serving Business: Growth Target

Commercial Load ⁽¹⁾

2013 – 2016 TWh

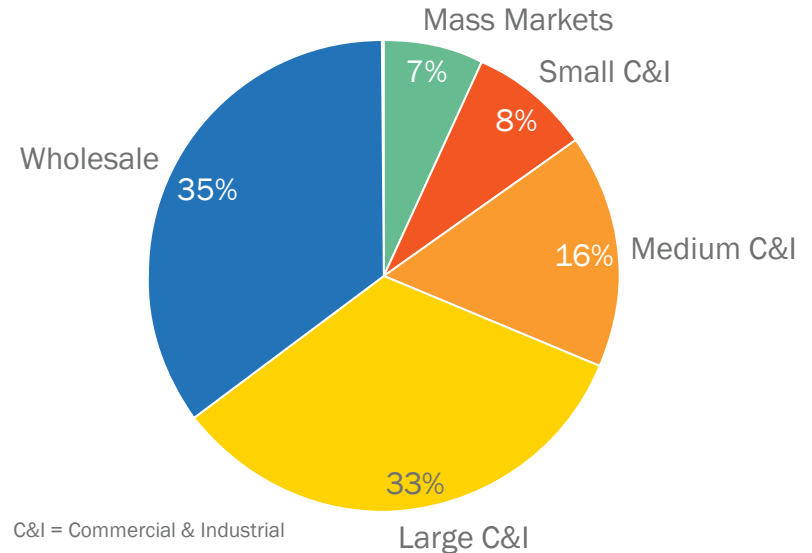


(1) Numbers and percentages are rounded to the nearest 5

(2) Index load expected to be 20% to 30% of total forecasted retail load

Load Split by Customer Class

(2013 TWh)



Customer Type	Load Size
Mass Markets	<1,000 MWhs per year
Small C&I	1,001-5,000 MWhs per year
Medium C&I	5,001-25,000 MWhs per year
Large C&I	>25,000 MWhs per year

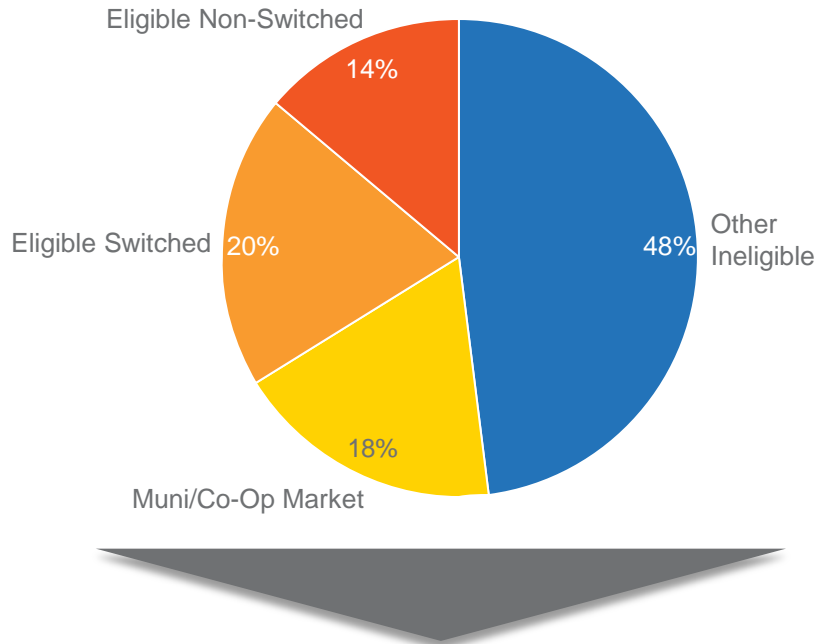
Focus on disciplined pricing and maximizing margin potential through all channels to market

A diverse set of customers enhances margin opportunities from a sales and portfolio management standpoint

Electric Load Serving Business: Strategy

Total U.S. Power Market in 2013

Estimated Load ~ 3,700 TWh ⁽¹⁾



Through retail and wholesale channels, Constellation currently serves 150 TWhs, or approximately 4%, of total U.S. power demand

Expected Total Competitive Market Growth

- Underlying load growth
 - Approx. 1% load growth across the U.S.
- Switched market expected to grow by approximately 5% in C&I from 2013-2016
- Switched market expected to grow by approximately 3% in Residential from 2013-2016

Strategy to Grow

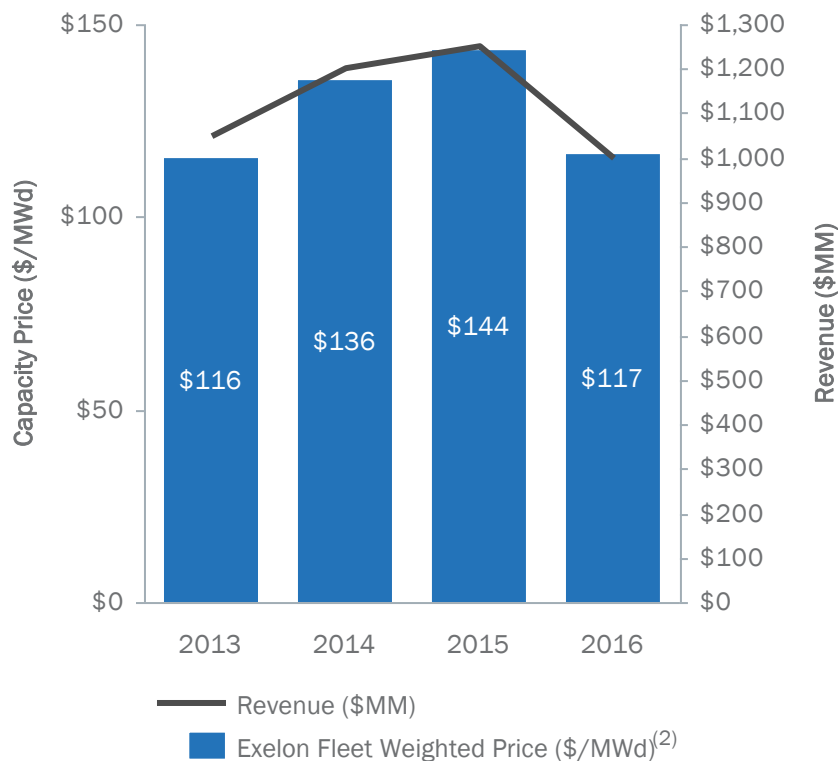
- Improve market share in existing markets
- Cross sell suite of products to existing customers
 - Create more value with customers
 - Utilize data and technology to expand product offerings
 - Achieve higher renewal rates
 - Distinguish our brand
- Leverage operational efficiency

Constellation is well positioned in a U.S. market where capacity available for competitive supply has room to grow

(1) Source: EIA, KEMA and internal estimates.

Capacity Markets

PJM RPM Capacity Revenues⁽¹⁾



2012/ 2013	2013/ 2014	2014/ 2015	2015/ 2016	2016/ 2017
---------------	---------------	---------------	---------------	---------------

PJM^(3,8)						
RTO	<i>Capacity</i>	12,800	11,500	11,500	11,500	11,250
	<i>Price</i>	\$16	\$28	\$126	\$136	\$59
EMAAC	<i>Capacity⁽⁴⁾</i>	9,100	9,100	9,100	9,100	9,100
	<i>Price</i>	\$140	\$245	\$137	\$168	\$119
MAAC	<i>Capacity</i>	2,600	2,700	2,700	2,700	2,700
	<i>Price</i>	\$133	\$226	\$137	\$168	\$119
SWMAAC	<i>Capacity⁽⁵⁾</i>	1,800	1,800	1,800	1,800	1,800
	<i>Price</i>	\$133	\$226	\$137	\$168	\$119
Average Exelon		\$78	\$142	\$132	\$153	\$92
New England⁽⁶⁾						
NEMA	<i>Capacity</i>	2,100	2,100	2,100	2,100	2,100
	<i>Price</i>	\$85 ⁽⁷⁾	\$85 ⁽⁷⁾	\$107	\$114	\$219
Rest of Pool	<i>Capacity</i>	735	735	735	735	735
	<i>Price</i>	\$85 ⁽⁷⁾	\$85 ⁽⁷⁾	\$95 ⁽⁷⁾	\$104 ⁽⁷⁾	\$90
NYISO⁽⁸⁾						
Rest of Pool	<i>Capacity</i>	1,100	1,100	1,100	1,100	1,100
MISO⁽⁹⁾						
AMIL	<i>Capacity</i>	1,100	1,100	1,100	1,100	1,100

RTO = Regional Transmission Organization, MAAC = Mid-Atlantic Area Council, EMAAC = Eastern Mid-Atlantic Area Council, SWMAAC = South West Mid-Atlantic Area Council, NEMA = North East Massachusetts; SEMA = North East Massachusetts, AMIL = Ameren Illinois.

(6) Reflects Qualified Summer Capacity including owned and contracted units.

(7) Price is pro-rated for auctions that clear at the floor price and there is more capacity procured than suggested by the reliability requirement.

(8) Reflects 50.01% ownership in CENG.

(9) Does not include wind under PPA.

(1) Revenues reflect capacity cleared in base and incremental auctions and are for calendar years. Revenue rounded to nearest \$50M.

(2) Weighted average \$/MW-Day would apply if all owned generation cleared.

(3) Reflects owned and contracted generation Installed Capacity (ICAP) adjusted for mid-year PPA roll offs.

(4) ICAP is net of Eddystone 1&2, Cromby 1&2 and Schuylkill 1 (total ~ 1,100 MW).

(5) ICAP is net of units to be divested (Brandon Shores, Wagner & Crane ~2,648 MW; Constellation offered these units in PY11/12 - PY 15/16 auctions) and Riverside 6 CT (~115MW).

Retail and Wholesale Gas

Retail Gas

Portfolio Size:

- 410 Bcf expected to be served in 2013 with moderate growth thereafter
- Month by month renewals, with high retention rates

Market Potential:

- All states are competitive markets with an estimated total market size of 15,000 Bcf, of which 7,500 Bcf is currently switched

Growth Strategy and Objectives:

- Looking to grow Northeast gas markets as well as ONEOK territories

Wholesale Gas

Portfolio Size:

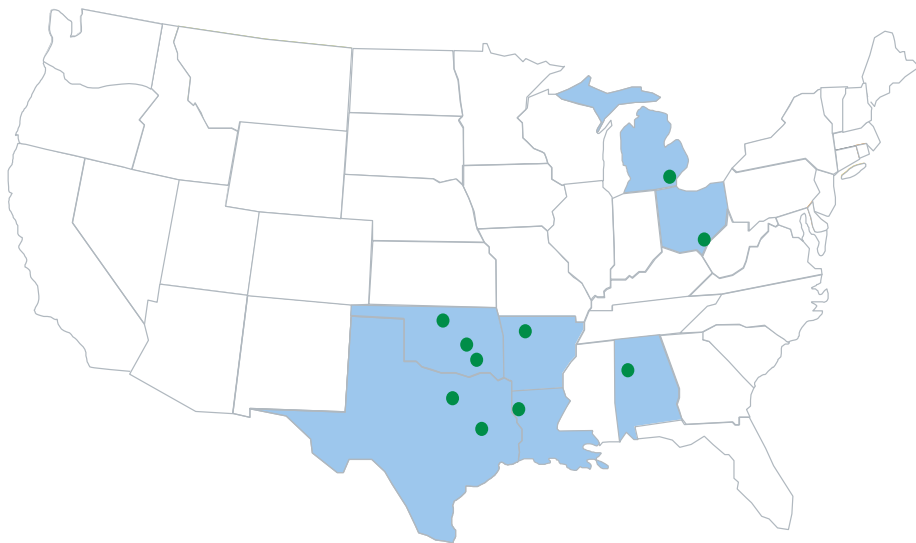
- 8 Bcf wholesale storage
- 450,000 MMBtu's per day of term transport
- Over 1 Bcf/day of plant supply
- ~4Bcf/day of NG flows to meet growing customer business, asset optimization, and plant supply

Growth Strategy and Objectives:

- Continue to expand wholesale presence to complement power assets
- Increase market knowledge of regional and basis transport information to assist power forecasting
- Continue to expand physically based customer business
- Continue to grow NG asset portfolio that complements customer business & plant supply requirements

(1) Estimate as of 9/30/2013.

Upstream E&P Assets



Current Portfolio Of Investments

Mississippi lime (OK)	Floyd shale (AL)
Hunton dewatering (OK)	Ohio shale (OH)
Woodford shale (OK)	Woodbine shale (TX)
Fayetteville shale (AR)	Trenton Black River (MI)
Haynesville shale (LA)	Barnett shale (TX)

(1) Oil/NGL conversion to gas is 6:1.

(2) Constellation does not operate any of its properties.
Note: E&P = Exploration and Production

(3) 12/31/12 Year end reserves excluding Eagle Ford

(4) Net daily production as of Q2 2013 excluding Eagle Ford

Investment Thesis

- Our Upstream Gas business achieves strong returns (>12% IRR)
- \$125m (~62% utilized) Reserve Based Lending (RBL) facility in place
 - Receives off-balance sheet treatment from S&P
- Provides valuable market intelligence in complex natural gas markets

Forecasted Production

	<u>2013</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>
Net Daily Prod (MMcfe / day)	55 - 70	45 - 60	45 - 60	60 - 75

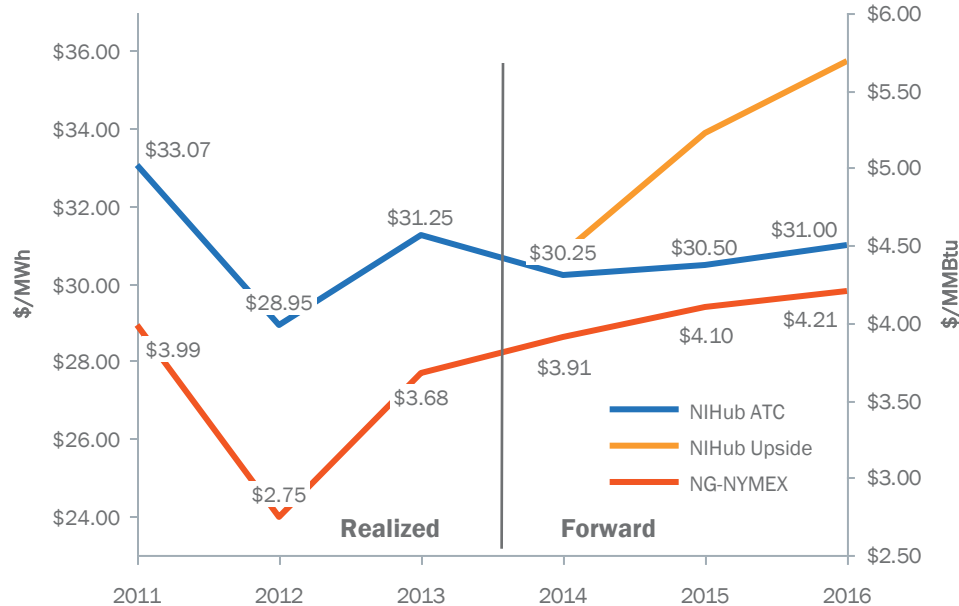
Estimated Net Proved
Reserves
(as of 12/31/12)³

255 Bcfe

Average Net Daily
Production
(Q2 2013)⁴

61.0 MMcfe

Energy Price Upside - NIHub



Key Drivers

- Year over year increases in fuel prices
- Current and future coal retirements
- Higher variable unit costs due to MATS
- Modest load growth
- Offset by new generation (gas and renewable)

Other factors (not included)

- Demand Response energy bidding
- Increased variable costs due to RGGI
- Scarcity pricing

- The charts above illustrates NIHub prices from 2011 to 2016 (realized through 2013) and NYMEX natural gas for the same time period
- In 2012 we saw low prices in the natural gas and power markets.
 - Natural gas prices settled \$2.75 for the year and NIHub ATC prices settled ~\$29.00. The forward market for NIHub continues to trade between \$30.50 and \$31.00 even though forward natural gas prices are between \$1.00 - \$1.50 per MMBtu higher than the spot levels we saw in 2012.

We continue to believe there is \$4 of upside in NiHub energy prices in 2015/2016 driven by several factors including compliance with environmental regulations

Exelon Generation Disclosures

September 30, 2013

(As disclosed in Third Quarter 2013 Earnings materials)

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, investment-grade credit rating)
- Hedge enough commodity risk to meet future cash requirements under a stress scenario

Three-Year Ratable Hedging

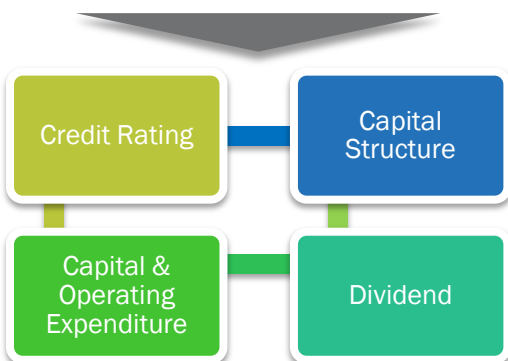
- Ensure stability in near-term cash flows and earnings
 - Disciplined approach to hedging
 - Tenor aligns with customer preferences and market liquidity
 - Multiple channels to market that allow us to maximize margins
 - Large open position in outer years to benefit from price upside

Bull / Bear Program

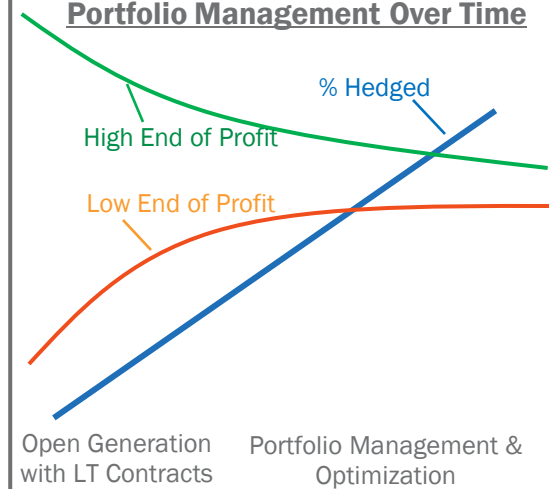
- Ability to exercise fundamental market views to create value within the ratable framework
 - Modified timing of hedges versus purely ratable
 - Cross-commodity hedging (heat rate positions, options, etc.)
 - Delivery locations, regional and zonal spread relationships

Align Hedging & Financials

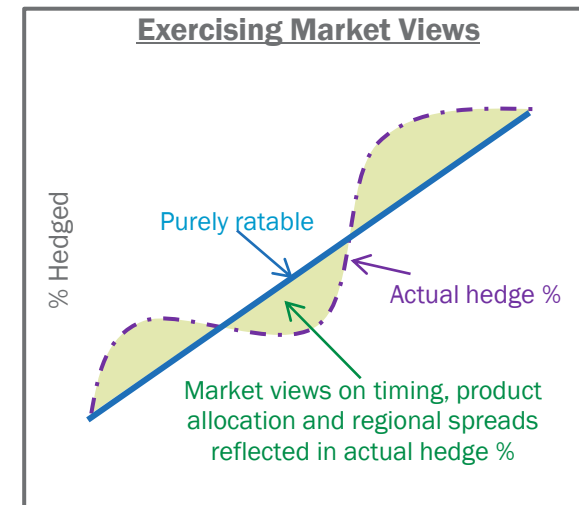
Establishing Minimum Hedge Targets



Portfolio Management Over Time



Exercising Market Views

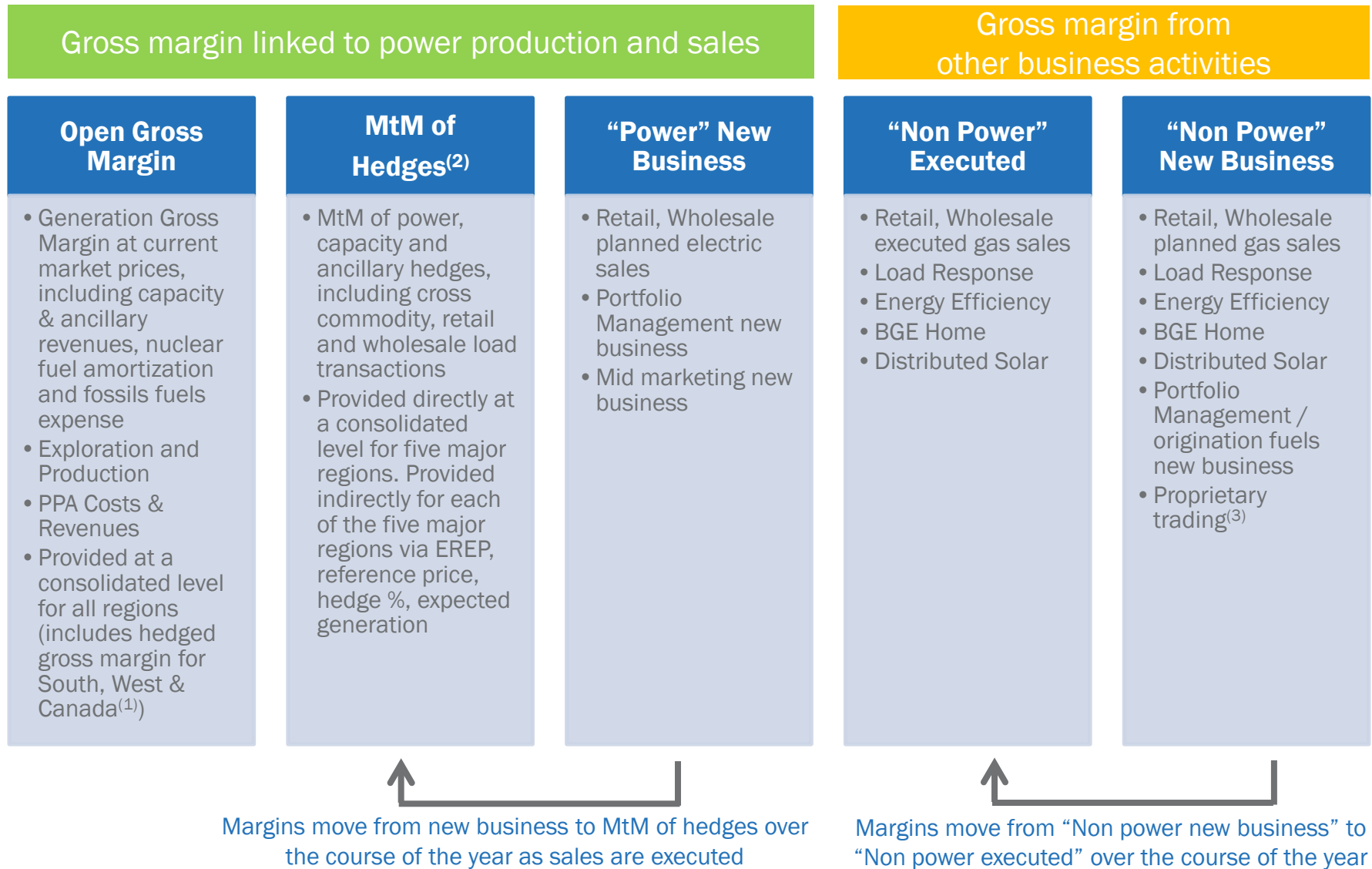


Protect Balance Sheet

Ensure Earnings Stability

Create Value

Components of Gross Margin Categories



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

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

(3) Proprietary trading gross margins will remain within “Non Power” New Business category and not move to “Non power” executed category.

ExGen Disclosures

Gross Margin Category (\$M) ^(1,2)	2013	2014	2015	2016
Open Gross Margin (including South, West & Canada hedged GM) ⁽³⁾	\$5,600	\$5,650	\$5,800	\$5,800
Mark to Market of Hedges ^(3,4)	\$1,700	\$900	\$450	\$250
Power New Business / To Go	\$50	\$500	\$750	\$750
Non-Power Margins Executed ⁽⁵⁾	\$400	\$200	\$100	\$100
Non-Power New Business / To Go ⁽⁵⁾	\$200	\$400	\$500	\$500
Total Gross Margin	\$7,950	\$7,650	\$7,600	\$7,400

Reference Prices ⁽⁶⁾	2013	2014	2015	2016
Henry Hub Natural Gas (\$/MMbtu)	\$3.65	\$3.86	\$4.06	\$4.17
Midwest: NiHub ATC prices (\$/MWh)	\$31.18	\$30.25	\$30.47	\$30.99
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$37.58	\$37.19	\$37.53	\$38.13
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	\$1.09	\$6.30	\$8.18	\$7.13
New York: NY Zone A (\$/MWh)	\$37.07	\$35.54	\$35.70	\$36.07
New England: Mass Hub ATC Spark Spread(\$/MWh) <i>ALQN Gas, 7.5HR, \$0.50 VOM</i>	\$3.70	\$4.88	\$3.69	\$2.33

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

(2) Gross margin does not include revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners and entities consolidated solely as a result of the application of FIN 46R.

(3) Includes CENG Joint Venture.

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

(5) Any changes to new business estimates for our non-power business are presented as revenue less costs of sales.

(6) Based on September 30, 2013 market conditions.

ExGen Disclosures

Generation and Hedges	2013	2014	2015	2016
<u>Exp. Gen (GWh) ⁽¹⁾</u>	214,700	215,500	209,400	211,000
Midwest	97,200	96,900	96,400	97,400
Mid-Atlantic ⁽²⁾	74,500	73,600	70,100	71,400
ERCOT	13,200	17,800	19,600	19,400
New York ⁽²⁾	14,000	12,500	9,300	9,300
New England	15,800	14,700	14,000	13,500
<u>% of Expected Generation Hedged ⁽³⁾</u>	97-100%	84-87%	48-51%	19-22%
Midwest	97-100%	85-88%	47-50%	16-19%
Mid-Atlantic ⁽²⁾	97-100%	90-93%	56-59%	21-24%
ERCOT	92-95%	81-84%	39-42%	31-34%
New York ⁽²⁾	98-101%	87-90%	54-57%	19-22%
New England	95-98%	49-52%	22-25%	7-10%
<u>Effective Realized Energy Price (\$/MWh) ⁽⁴⁾</u>				
Midwest	\$37.00	\$33.50	\$33.00	\$34.00
Mid-Atlantic ⁽²⁾	\$49.00	\$45.00	\$45.00	\$49.00
ERCOT ⁽⁵⁾	\$24.00	\$11.00	\$9.50	\$6.50
New York ⁽²⁾	\$32.00	\$37.00	\$42.50	\$39.50
New England ⁽⁵⁾	\$6.00	\$3.50	\$2.00	\$5.50

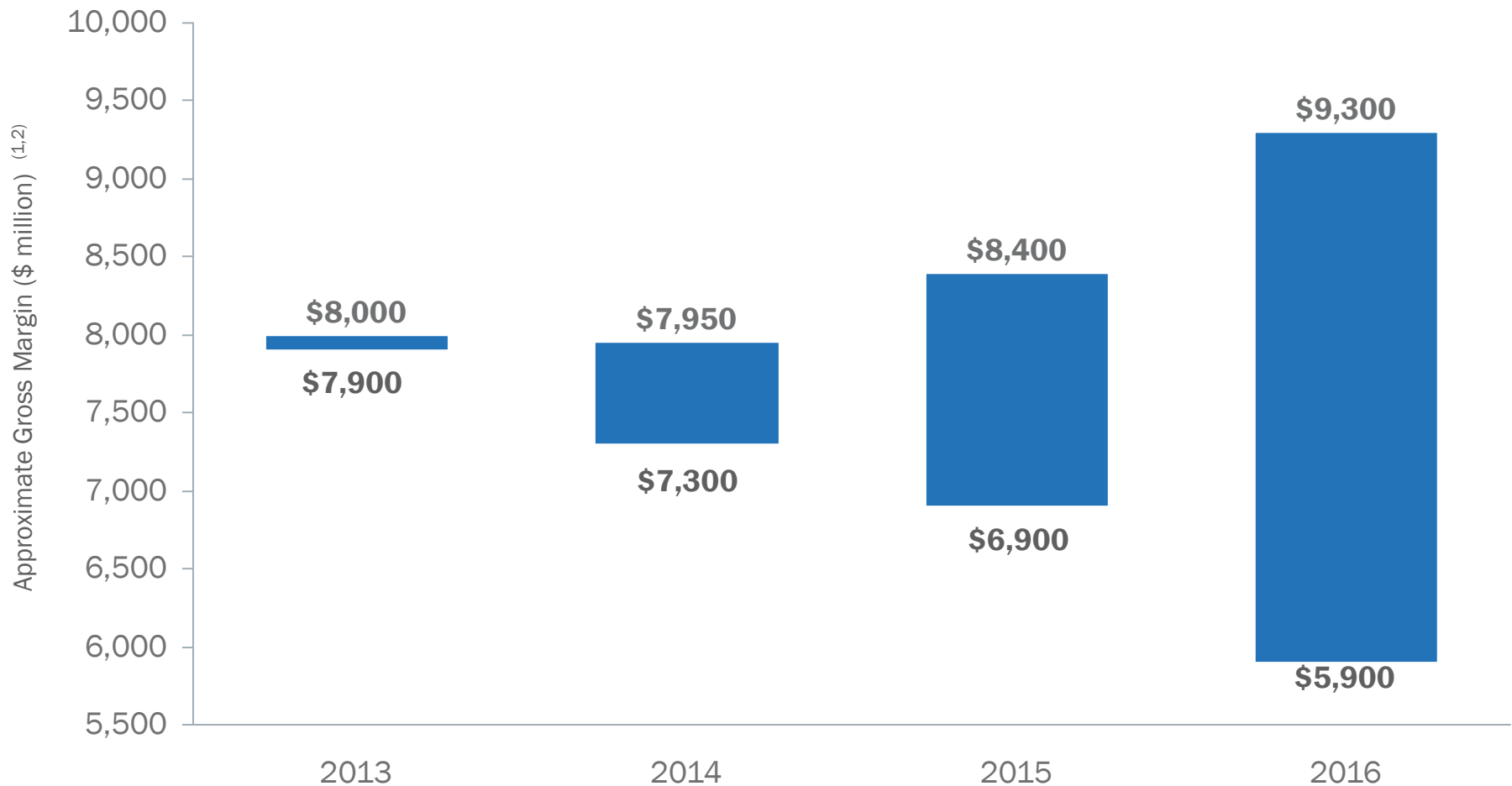
(1) Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted for capacity. Expected generation is based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 12 refueling outages in 2013, 14 refueling outages in 2014 and 2015 and 12 refueling outages in 2016 at Exelon-operated nuclear plants, Salem and CENG. Expected generation assumes capacity factors of 94.1%, 93.7%, 93.3%, and 94.4% in 2013, 2014, 2015 and 2016 at Exelon-operated nuclear plants excluding Salem and CENG. These estimates of expected generation in 2014, 2015 and 2016 do not represent guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years. (2) Includes 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. Uses expected value on options. (4) Effective realized energy price is representative of an all-in hedged price, on a per MWh basis, at which expected generation has been hedged. It is developed by considering the energy revenues and costs associated with our hedges and by considering the fossil fuel that has been purchased to lock in margin. It excludes uranium costs and RPM capacity revenue, but includes the mark-to-market value of capacity contracted at prices other than RPM clearing prices including our load obligations. It can be compared with the reference prices used to calculate open gross margin in order to determine the mark-to-market value of Exelon Generation's energy hedges. (5) Spark spreads shown for ERCOT and New England.

ExGen Hedged Gross Margin Sensitivities

Gross Margin Sensitivities (With Existing Hedges) (1, 2, 3)	2013	2014	2015	2016
Henry Hub Natural Gas (\$/MMbtu)				
+ \$1/Mmbtu	\$10	\$110	\$370	\$575
- \$1/Mmbtu	\$0	\$(45)	\$(305)	\$(550)
NiHub ATC Energy Price				
+ \$5/MWh	\$0	\$65	\$325	\$450
- \$5/MWh	\$0	\$(60)	\$(325)	\$(450)
PJM-W ATC Energy Price				
+ \$5/MWh	\$0	\$35	\$175	\$290
- \$5/MWh	\$0	\$(35)	\$(170)	\$(280)
NYPP Zone A ATC Energy Price				
+ \$5/MWh	\$0	\$5	\$20	\$35
- \$5/MWh	\$0	\$(10)	\$(20)	\$(35)
Nuclear Capacity Factor				
+/- 1%	+/- \$10	+/- \$40	+/- \$45	+/- \$45

(1) Based on September 30, 2013 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. (2) Sensitivities based on commodity exposure which includes open generation and all committed transactions. (3) Includes CENG Joint Venture.

Exelon Generation 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 2014, 2015 and 2016 do not represent earnings guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years. The price distributions that generate this range are calibrated to market quotes for power, fuel, load following products, and options as of September 30, 2013 (2) Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions.

Illustrative Example of Modeling Exelon Generation 2014 Gross Margin

ZECJ-FIN-21

PUBLIC

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	<div><div></div><div>\$5.65 billion</div><div></div></div>					
(B)	Expected Generation (TWh)	96.9	73.6	17.8	12.5	14.7	
(C)	Hedge % (assuming mid-point of range)	86.5%	91.5%	82.5%	88.5%	50.5%	
(D=B*C)	Hedged Volume (TWh)	83.8	67.3	14.7	11.1	7.4	
(E)	Effective Realized Energy Price (\$/MWh)	\$33.50	\$45.00	\$11.00	\$37.00	\$3.50	
(F)	Reference Price (\$/MWh)	\$30.25	\$37.19	\$6.30	\$35.54	\$4.88	
(G=E-F)	Difference (\$/MWh)	\$3.25	\$7.81	\$4.70	\$1.46	\$(1.38)	
(H=D*G)	Mark-to-market value of hedges (\$ million) ⁽¹⁾	\$275 million	\$525 million	\$70 million	\$15 million	\$(10) million	
(I=A+H)	Hedged Gross Margin (\$ million)	\$6,550 million					
(J)	Power New Business / To Go (\$ million)	\$500 million					
(K)	Non-Power Margins Executed (\$ million)	\$200 million					
(L)	Non- Power New Business / To Go (\$ million)	\$400 million					
(N=I+J+K+L)	Total Gross Margin	\$7,650 million					

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

Constellation Energy Nuclear Group (CENG) Background

As a result of Exelon's equity interest in CENG, CENG gross margins and earnings are reflected in ExGen disclosures and other financial statements. The following is information related to PPA contracts between CENG and 3rd parties and the PPA between CENG and its equity parents.

	<u>Calvert 1&2</u>	<u>NMP 1</u>	<u>NMP 2 ⁽¹⁾</u>	<u>Ginna⁽²⁾</u>	
<u>Ownership Interest</u>					
Total Plant Capacity	1,756 MW	617 MW	1,279 MW	577 MW	
Ownership Split	100% CENG	100% CENG	82% CENG / 18% LIPA	100% CENG	
ExGen Ownership (50.01% of CENG)	878 MW	308 MW	524 MW	288 MW	
<u>PPA structure (% output)</u>					
CENG Legacy PPA with Utilities	-	-	See footnote 1	90% < June 2014	0% > June 2014
CENG PPA with Parents	100%	100%	100%	10% < June 2014	100% > June 2014

CENG PPA with Parents				
5 year contract extendable at end of each year for additional year - Market based pricing and monthly, rolling 3 year hedge profile (100%, 60%, 30%)				
	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>
(% of uncommitted output)				
EDF Trading	15	15	15	N.A.
ExGen	85	85	85	N.A.

(1) Nine Mile Point 2 (NMP) has a revenue sharing agreement (via a call option type contract) on 80% of the output.

(2) Ginna Legacy PPA at \$44/MWh; CENG PPA with parents (ExGen, EDF) at close to market prices and designed to maintain a monthly ratable profile for CENG.

Constellation Energy Nuclear Group (CENG) Background

ExGen Disclosures Forward Estimates

- ExGen forward disclosures reflect the gross position that accrues to ExGen from ownership interest in CENG and PPA with CENG as of a certain date
- **Open Gross Margin:** Reflects proportionate share of CENG revenues and fuel costs, market value of PPA less PPA costs paid by ExGen to CENG
- **MtM of Hedges:** Reflects MtM of any hedges placed by ExGen for managing position arising from ownership interests or PPAs with CENG
- **Expected Generation:** Reflects proportionate ownership in CENG and generation associated with PPA between CENG and ExGen.
- **Hedge Percentage:** Reflects hedges placed by ExGen to hedge exposure arising from CENG position (owned or contracted)
- **Effective Realized Energy Price:** Reflects MtM and hedges from CENG position (owned or contracted)

Financial Statements (10-Q, 10-K, Earnings Release tables) Actuals

- ExGen actuals reflect equity method accounting treatment for ownership interest in CENG and regular treatment for PPA between ExGen and CENG.
- **RnF:** Includes net PPA gross margin (revenues less costs) between ExGen and CENG. CENG earnings or gross margin are not included, and are instead shown under “CENG equity earnings” on the income statement.
- **Total Supply:** Includes only the generation corresponding to the PPA between ExGen and CENG.
- **Average Margins (\$/MWh):** Includes only margins corresponding to PPA between ExGen and CENG as well as any hedges placed by ExGen

Generation



Exelon Generation Fleet

National Scope

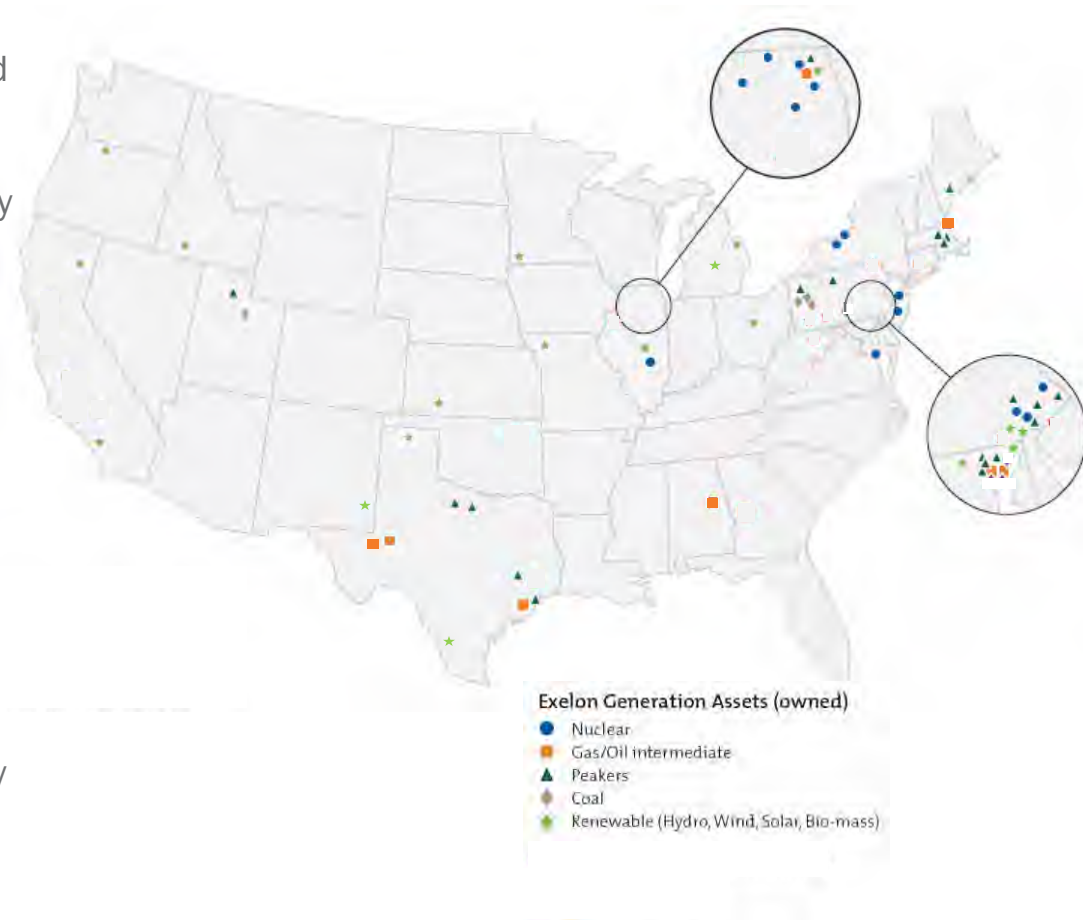
- Power generation assets in 20 states and Canada
- Low-cost generation capacity provides unparalleled leverage to rising commodity prices

Large and Diverse

- 35 GW of diverse generation⁽¹⁾
 - 19 GW of Nuclear
 - 10 GW of Gas
 - 2 GW of Hydro
 - 2 GW of Oil
 - 1 GW of Coal
 - 1 GW of Wind/Solar/Other

Clean

- One of nation's cleanest fleets as measured by CO₂, SO₂ and NO_x intensity
- Less than 5% of generation capacity will require capital expenditures to comply with Air Toxic rules



A clean and diverse portfolio that is well positioned for environmental upside from EPA regulations

(1) Total owned generation capacity as of 9/30/2013. Nuclear capacity reflects EXC ownership of CENG and Salem.

Executing on Generation Development and Growth Projects

Solar

- Antelope Valley Solar Ranch Project One
 - Large scale solar project that will be 230 MW once fully operational
 - 128 MW currently online, additional 54 MW by Fall 2013
 - 48 MW by first half of 2014
 - Initial investment fully recovered by 2015
 - 25-year PPA for entire output with Pacific Gas & Electric
 - Cashflow and EPS accretive in 2013



Wind

- Six projects completed in 2012, added 404 MWs to the wind portfolio
 - All projects done under long-term PPAs with anticipated payback in approximately 10 years
- 45.6 MW wind farm in Michigan to be built in 2014



Nuclear Updates

- Peach Bottom Extended Power Uprate
 - Adding 130 MW
 - Online dates of 65 MW in Q1 2015 and 65 MW in Q1 2016



Expanding the contracted renewable portfolio of Solar and Wind while adding incremental MWs to our existing nuclear fleet

Exelon Nuclear Fleet Overview (including CENG and Salem)

	Plant Location	Type/ Containment	Water Body	License Extension Status / License Expiration ⁽¹⁾	Ownership	Spent Fuel Storage/ Date to lose full core discharge capacity ⁽²⁾
Midwest	Braidwood, IL (Units 1 and 2)	PWR Concrete/Steel Lined	Kankakee River	Filed application in May 2013 (decision expected in 2015)/ 2026, 2027	100%	Dry Cask
	Byron, IL (Units 1 and 2)	PWR Concrete/Steel Lined	Rock River	Filed application in May 2013 (decision expected in 2015)/ 2024, 2026	100%	Dry Cask
	Clinton, IL (Unit 1)	BWR Concrete/Steel Lined / Mark III	Clinton Lake	2026	100%	Dry Cask (2016)
	Dresden, IL (Units 2 and 3)	BWR Steel Vessel / Mark I	Kankakee River	Renewed / 2029, 2031	100%	Dry Cask
	LaSalle, IL (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	Illinois River	2022, 2023	100%	Dry Cask
	Quad Cities, IL (Units 1 and 2)	BWR Steel Vessel / Mark I	Mississippi River	Renewed / 2032	75% Exelon, 25% Mid- American Holdings	Dry Cask
Mid-Atlantic	Calvert Cliffs, MD (Units 1 and 2)	PWR Concrete/Steel Lined	Chesapeake Bay	Renewed / 2034, 2036	100% CENG ⁽⁴⁾	Dry Cask
	R.E. Ginna, NY (Unit 1)	PWR Concrete/Steel Lined	Lake Ontario	Renewed / 2029	100% CENG ⁽⁴⁾	Dry Cask
	Limerick, PA (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	Schuylkill River	Filed application in June 2011 (decision expected in 2015) / 2024, 2029	100%	Dry Cask
	Nine Mile Point, NY (Units 1 and 2)	BWR Steel Vessel / Mark I Concrete/Steel Vessel/ Mark II	Lake Ontario	Renewed / 2029, 2046	100% CENG ⁽⁴⁾ / 82% CENG ⁽⁴⁾ , 18% Long Island Power Authority	Dry Cask
	Oyster Creek, NJ (Unit 1)	BWR Steel Vessel / Mark I	Barnegat Bay	Renewed / 2029 ⁽³⁾	100%	Dry Cask
	Peach Bottom, PA (Units 2 and 3)	BWR Steel Vessel / Mark I	Susquehanna River	Renewed / 2033, 2034	50% Exelon, 50% PSEG	Dry Cask
	TMI, PA (Unit 1)	PWR Concrete/Steel Lined	Susquehanna River	Renewed / 2034	100%	2023
	Salem, NJ (Units 1 and 2)	PWR Concrete/Steel Lined	Delaware River	Renewed / 2036, 2040	42.6% Exelon, 57.4% PSEG	Dry Cask

(1) Operating license renewal process takes approximately 4-5 years from commencement until completion of NRC review.

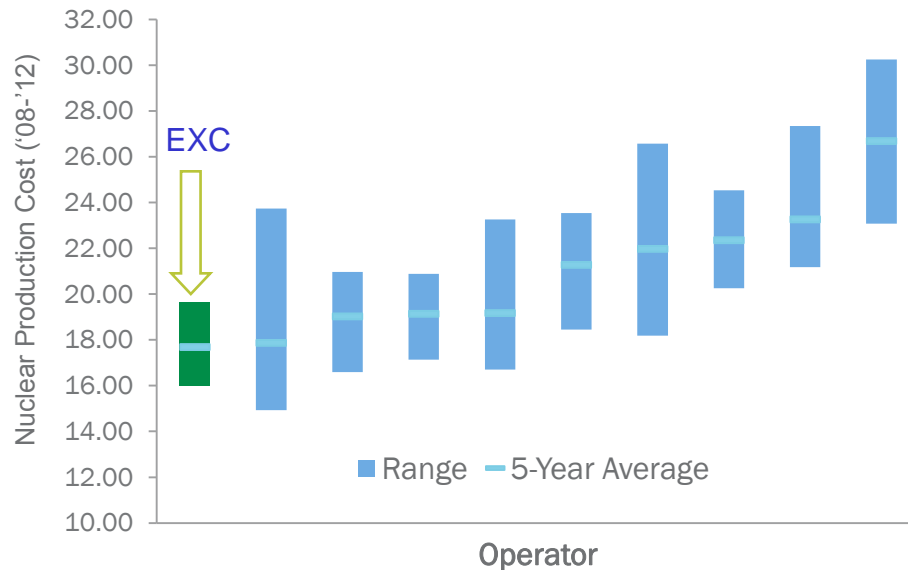
(2) The date for loss of full core reserve identifies when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core. Dry cask storage will be in operation at those sites prior to losing full core discharge capacity in their on-site storage pools.

(3) On 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.

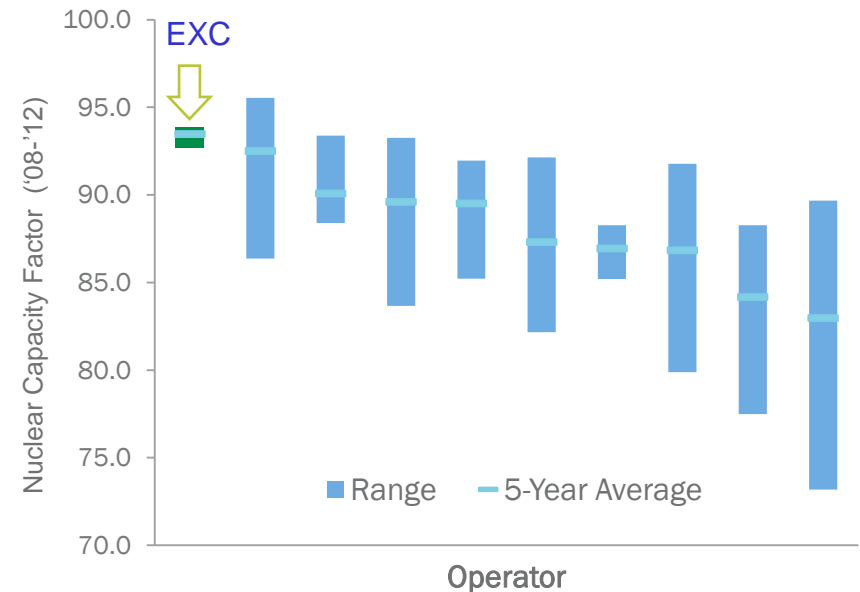
(4) Exelon Generation has a 50.01% ownership interest in CENG (Constellation Energy Nuclear Group, LLC). Electricite de France SA (EDF) has a 49.99% ownership interest in CENG.

World Class Nuclear Operator⁽¹⁾

Nuclear Production Cost (\$/MWh)⁽²⁾



Capacity Factor (%)⁽³⁾



Among major nuclear plant fleet operators, Exelon is consistently one of the lowest-cost and most efficient producers of electricity in the nation

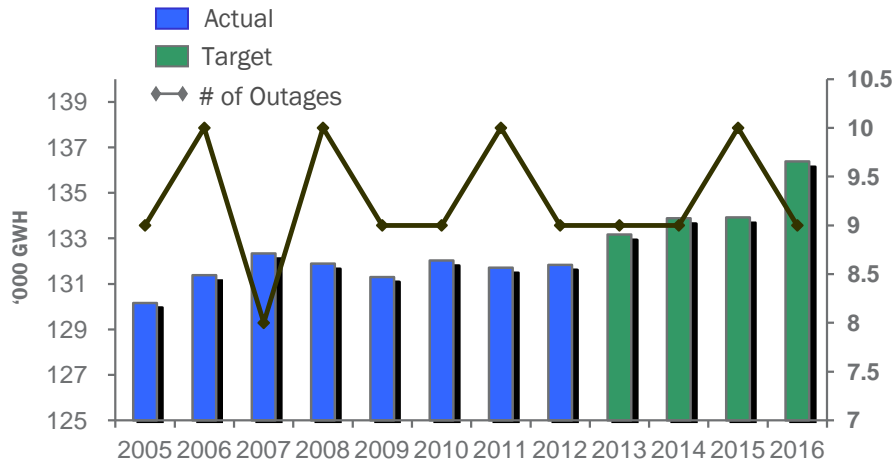
(1) Exelon fleet averages exclude Salem and CENG

(2) Source: 2012 Electric Utility Cost Group (EUCG) survey. Includes Fuel Cost plus Direct O&M divided by net generation.

(3) Source: Platts Nuclear News, Nuclear Energy Institute and Energy Information Administration (Department of Energy).

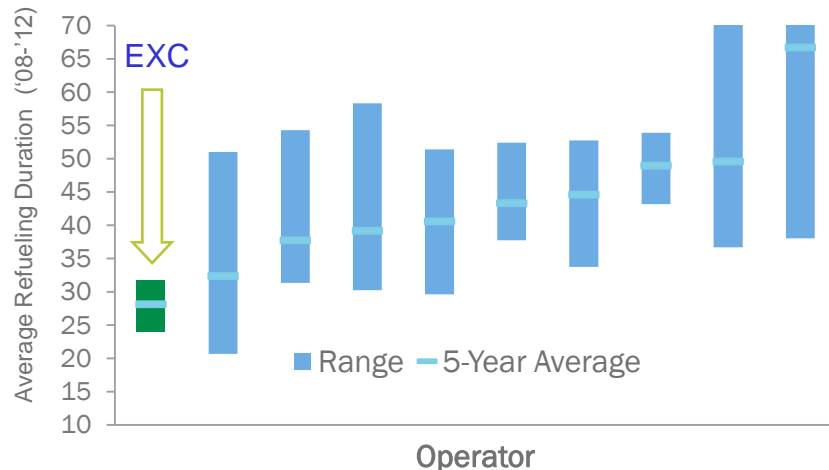
Nuclear Output and Refueling Outages

Nuclear Output⁽¹⁾



(1) Net nuclear generation data at ownership excluding Salem and CENG. 2016 includes Clinton Refueling Only outage of shortened duration.

Fleet Average Refueling Outage Duration (Days)⁽¹⁾



(1) Exelon fleet averages exclude Salem and CENG.

Nuclear Refueling Cycle

- All Exelon owned units on a 24 month cycle except for Braidwood U1/U2, Byron U1/U2 and Salem U1/U2, which are on 18 month cycles
- Starting in 2015 Clinton is on annual cycles

2013 Refueling Outage Impact

- 10 planned refueling outages, including 1 at Salem
- Exelon completed 4 refueling outages in the Spring with an average duration of 24 days
- Salem completed 1 refueling outage in the Spring
- 5 Exelon planned Fall refueling outages (Braidwood 1, Peach Bottom 3, Clinton, Three Mile Island and Dresden 2)

2014 Refueling Outage Impact

- 11 planned refueling outages, including 2 at Salem
- 5 Exelon planned Spring refueling outages and 4 planned Fall refueling outages
- 1 Salem planned Spring refueling outage and 1 planned Fall refueling outage

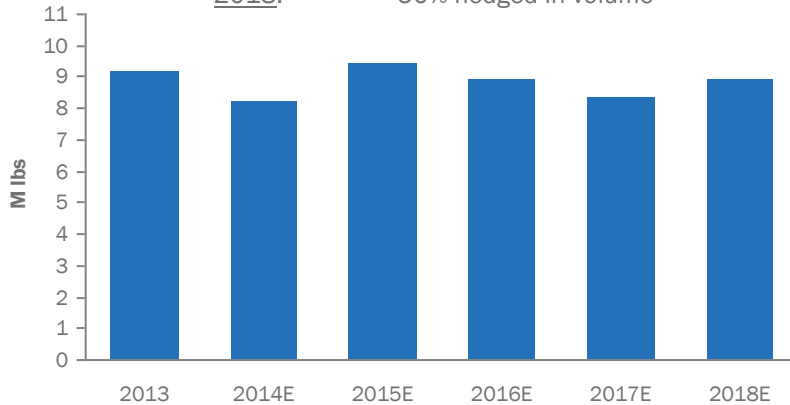
Nuclear Fuel Costs⁽¹⁾

Projected Exelon (100%) Uranium Demand

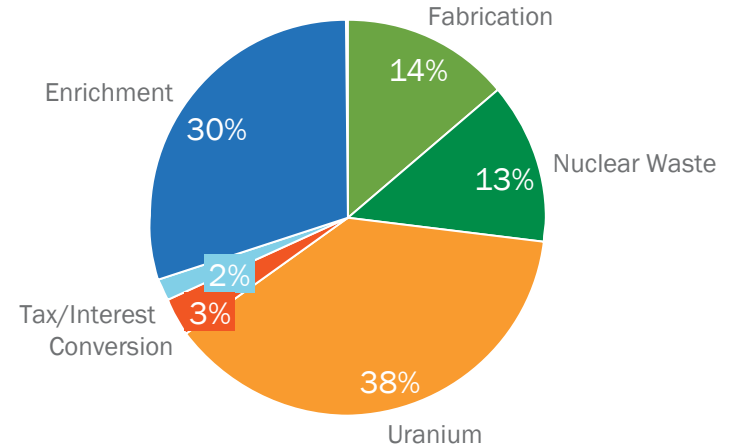
2013 – 2016: 100% hedged in volume

2017: ~80% hedged in volume

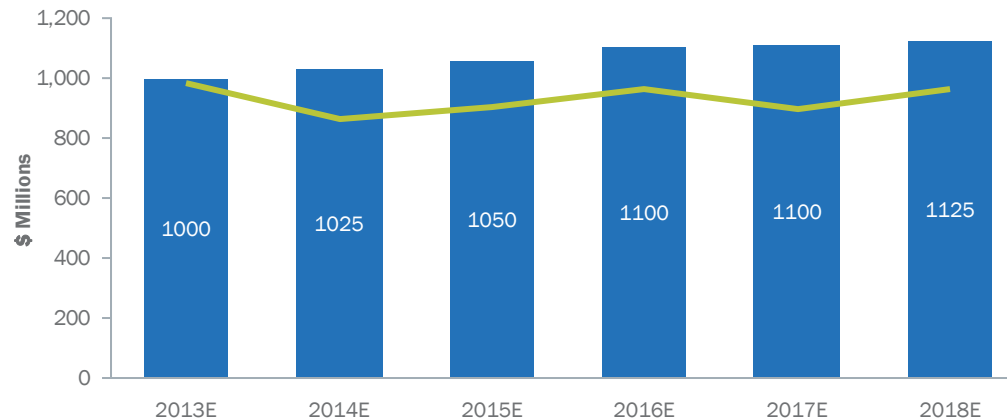
2018: ~50% hedged in volume



Components of Fuel Expense in 2013



Projected Total Nuclear Fuel Spend⁽²⁾



■ Nuclear Fuel Expense (Amortization + Spent Fuel)

— Nuclear Fuel Capex

(1) All charts exclude Salem and CENG.

(2) At ownership, excluding Salem and CENG. Excludes costs reimbursed under the settlement agreement with the DOE.

Constellation Energy Nuclear Group (CENG) Operating Services Agreement

ZECJ-FIN-21 PUBLIC

- Agreements signed between Exelon and EDF, with expected close in 2014 (first quarter or early second quarter)
- Nuclear Operating services agreement
 - Integrate CENG and their 3 plants into Exelon Nuclear with transfer of operating licenses
 - Utilize Exelon Nuclear Management Model to improve plant performance
 - Leverage scale and obtain cost efficiencies of running a larger, integrated fleet
 - Expect cost synergies of \$50-\$70M at 100% ownership
- Loan to CENG and distributions to EDF/Exelon Generation
 - Exelon Generation \$400M loan to CENG at 5.25% annual interest rate
 - CENG \$400M special distribution to EDF
 - Exelon Generation to receive preferred distributions from CENG's available cash flows until loan is fully repaid
 - Exelon Generation also to receive aggregate distributions of \$400M plus a return of 8.5% per annum from the date of the special dividend
- Option provision for EDF to sell its 49.99% interest in CENG to Exelon Generation
 - Exercisable from January 2016 to June 2022, priced at fair market value
- Indemnify EDF in the event of a future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations
 - Given Exelon's size and past performance, no material impact to premiums

Leverages Exelon's best-in-class operations, scale and low-cost fleet to add value