

Earnings Conference Call 2nd Quarter 2013

July 31st, 2013



Cautionary Statements Regarding Forward-Looking Information

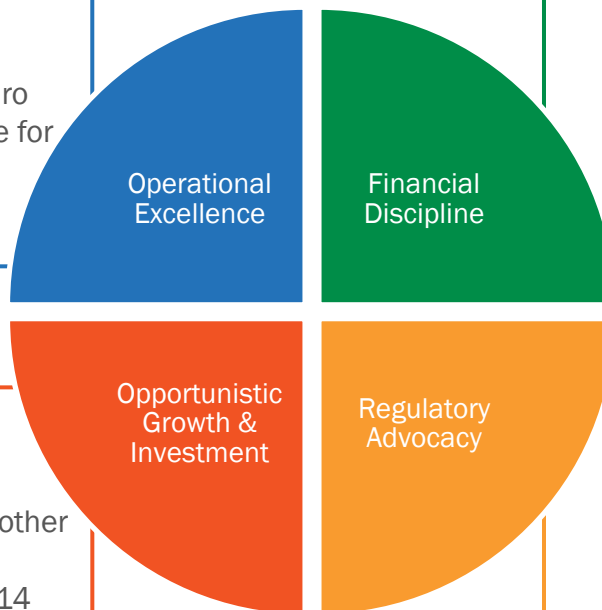
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This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially 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 First 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 17; 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 press release. 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.

2Q13 In Review

- 2Q13 nuclear capacity factor of 92.8% and YTD 2013 capacity factor of 94.6%
- Entered into agreement with EDF to operate the CENG plants
- Dispatch match rate for fossil and hydro fleet of 99.1% and energy capture rate for wind and solar fleet of 92.4%
- Top decile safety performance for ComEd, PECO and BGE



- Delivered 2Q earnings within our guidance range
- Canceled LaSalle and Limerick EPU projects
- On track to achieve \$550M of annual run-rate merger synergies by 2014
- Identified additional O&M savings at ExGen

- Current 5-year plan includes \$16B of growth CapEx (~\$13.5B at Utilities)
- Installed 99 MW at AVSR YTD with another 102 MW to come on line in 2013
- Adding 46 MW to wind portfolio in 2014 with the Beebe 1B project
- Continued smart meter installation at PECO, BGE and ComEd

- SB9 was enacted clarifying language in EIMA. ComEd made annual filing for distribution with ICC
- BGE filed a rate case in May with the MDPSC
- Engaged in PJM stakeholder process around RPM

2013 Expectations:

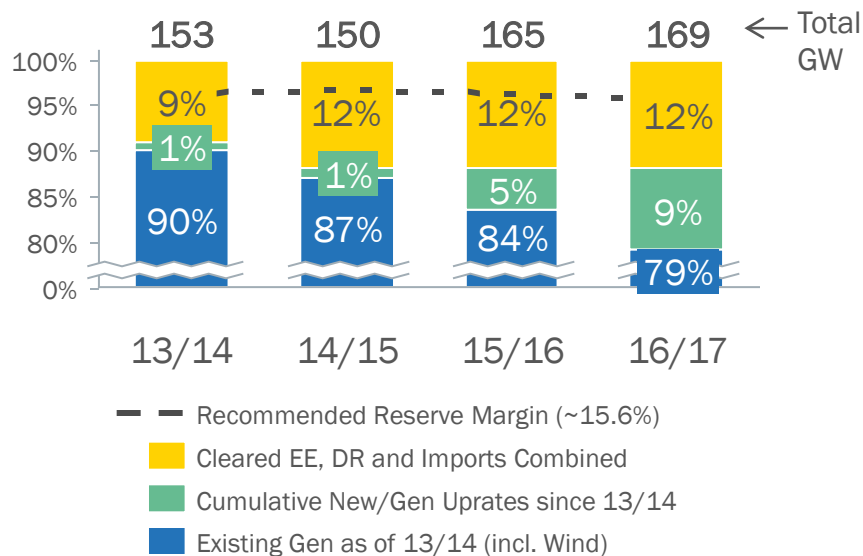
- **Deliver 3Q13 operating earnings within guidance range of \$0.60 - \$0.70/share ⁽¹⁾**
- **On-track to achieve full-year operating earnings within guidance range of \$2.35 - \$2.65/share ⁽¹⁾ as disclosed on 4Q12 earnings call**

AVSR = Antelope Valley Solar Ranch. EIMA = Energy Infrastructure Modernization Act. EPU = Extended Power Uprate. ICC = Illinois Commerce Commission. MDPSC = Maryland Public Service Commission. O&M = Operating & Maintenance. RPM = Reliability Pricing Model.

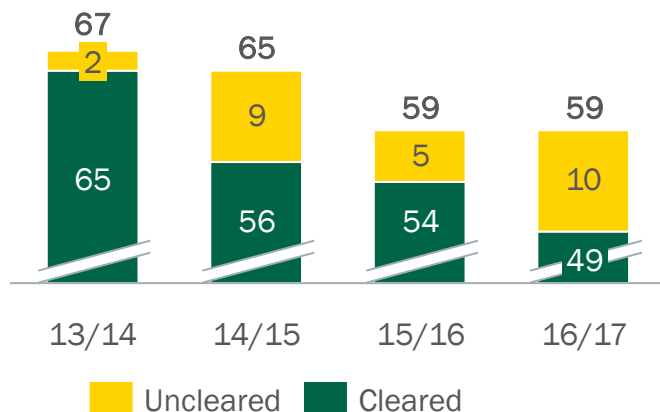
(1) Refer to Earnings Release Attachments for additional details and to the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS.

RPM Results

% of Unforced Capacity Procured by Type ⁽¹⁾



Coal Fired Gen-BRA Offers ⁽²⁾ (GW)



RPM Clearing Trends

- Decrease in existing coal-fired generation
 - 6.3 GW of coal retirements in 2012 alone
 - 10 GW in the PJM deactivation queue for 2013 - 2015
 - Internal estimate: ~ 22 GW for 2012 - 2016
- Increase in planned gas-fired generation
- Increase in cleared GW of Energy Efficiency (EE), Demand Response (DR), and Imports

BRA = Base Residual Auction. RPM = Reliability Pricing Model. PY = Plan Year.

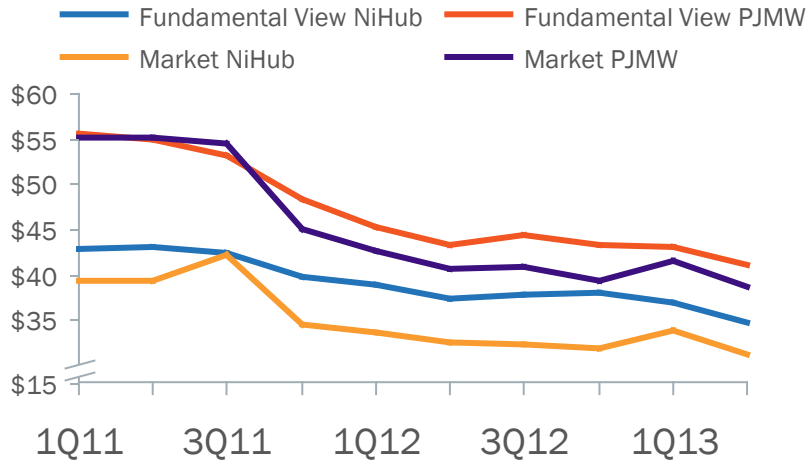
⁽¹⁾ Sources: (1) PJM RPM Base Residual Auction Results Reports (2) RPM Commitments by Fuel Type by DY

Notes: (1) PY 13/14 includes ATSI (2) PY 14/15 includes Duke (3) PY 15/16 includes significant portion of AEP and DEOK zone load previously under FRR alternative (4) PY 16/17 includes EKPC (5) PY 13/14 is base year for cumulative New Gen and Uprates

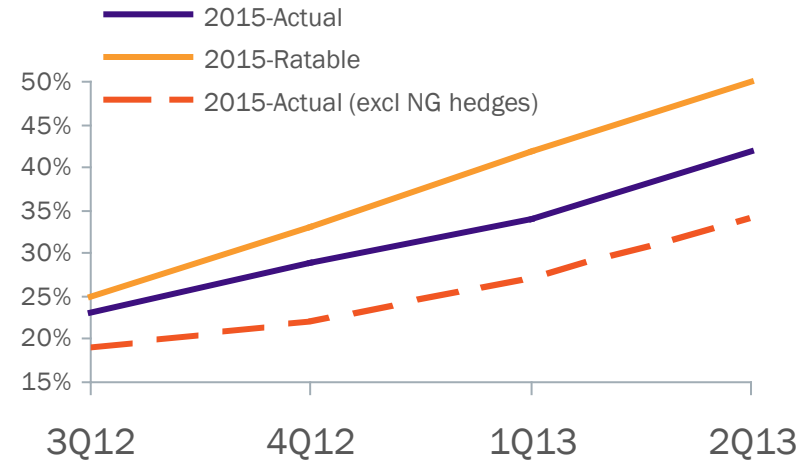
⁽²⁾ Estimated based on PY 16/17 PJM Base Residual Auction Results. Includes imports. For comparability, PJM geographical additions included by adding initial BRA offered and cleared quantities to previous years.

Hedging Activity and Market Fundamentals

Fundamental View vs. Market - 2015



% of Expected Generation Hedged ⁽¹⁾ - Total Portfolio



Market Fundamentals

- Structural changes in the stack are expected to increase volatility in the spot energy market and drive prices higher than current market
- Continue to see a disconnect in forward heat rates compared to our fundamental forecast given current natural gas prices, expected retirements, new generation resources, and load assumptions

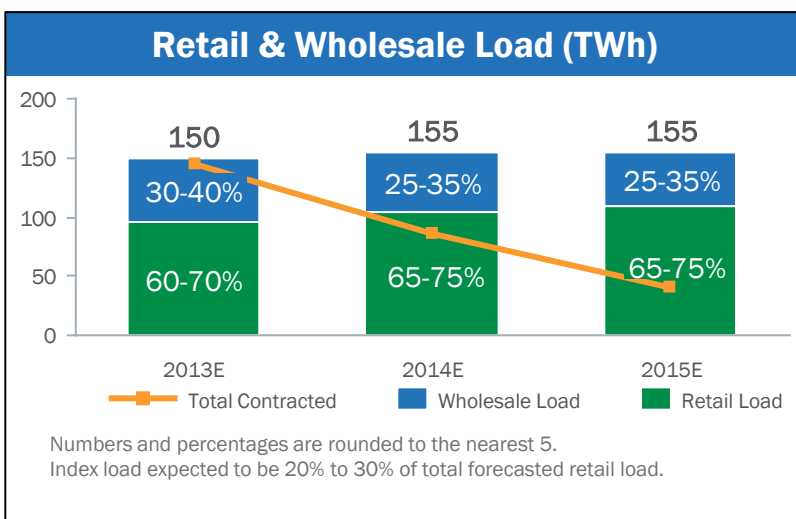
Impacts of our view on our hedging activity

- We align our hedging strategies with our fundamental views
- We have widened our deviation from ratable across our entire portfolio over the past 6 months to approximately 8%
- Use of natural gas as a cross-commodity hedge leaves more upside to heat rate expansion

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

Exelon Generation: Gross Margin Update

	June 30, 2013			Delta to March 31, 2013		
Gross Margin Category (\$M) ^{(1) (2)}	2013	2014	2015	2013	2014	2015
Open Gross Margin ⁽³⁾ (including South, West, Canada hedged gross margin)	5,750	5,700	5,900	(250)	(650)	(500)
Mark-to-Market of Hedges ^(3,4)	1,450	850	400	250	450	150
Power New Business / To Go	200	550	750	(150)	(50)	(50)
Non-Power Margins Executed	350	150	50	50	50	0
Non-Power New Business / To Go ⁽⁵⁾	250	450	550	(50)	(50)	0
Total Gross Margin	8,000	7,700	7,650	(150)	(250)	(400)



Key Changes in 2Q 2013

- 2013:** Reduction of \$50M due to unplanned nuclear outages and AVSR delays; \$50M due to FTR under collection; and \$50M due to lower power new business targets
- 2014:** \$200M reduction due to prices and \$50M reduction in power new business targets
- 2015:** \$350M reduction due to prices and \$50M reduction in power new business targets
- Reducing 2013 ExGen O&M by \$100M (\$50M at Constellation to offset lower new business targets) and targeting reductions in 2014 and 2015 to result in a roughly flat O&M CAGR for 2013 - 2015

- 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.

FTR = Financial Transmission Rights. CAGR = Compound Annual Growth Rate.

Key Financial Messages

- Delivered non-GAAP operating earnings⁽¹⁾ in 2Q of \$0.53/share within guidance range provided of \$0.50 - \$0.60/share

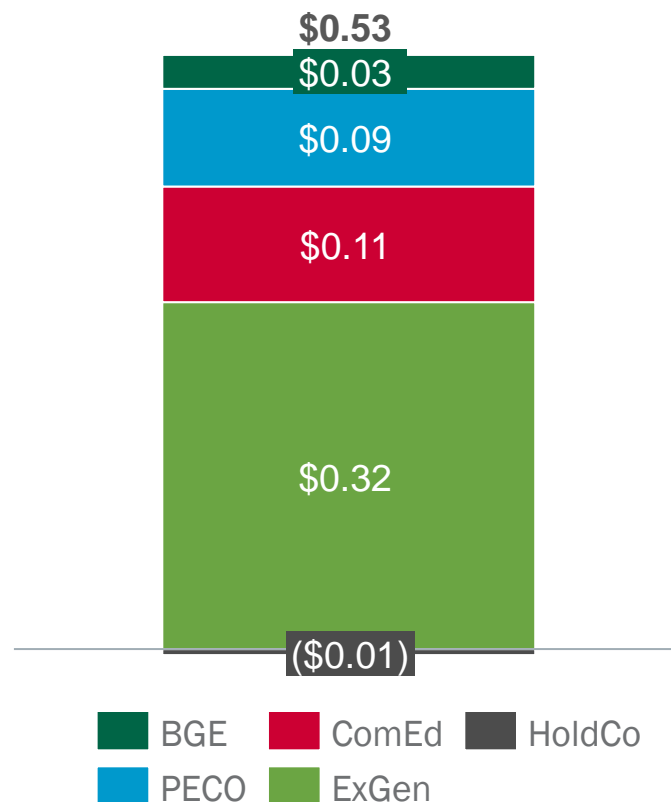
2Q 2013 vs. Guidance

- Reduction of wholesale new business targets and unplanned nuclear outages
- Favorable impacts of SB9 at ComEd

Full-Year 2013 vs. Guidance

- Reduction of wholesale new business targets
- Reduction of 2013 ExGen O&M by \$100M
- Favorable load at ComEd and PECO
- Lower ExGen effective tax rate
- Favorable interest related to tax positions
- Favorable impacts of SB9 at ComEd
- Lower depreciation and other favorable items at ExGen

2013 2Q Results

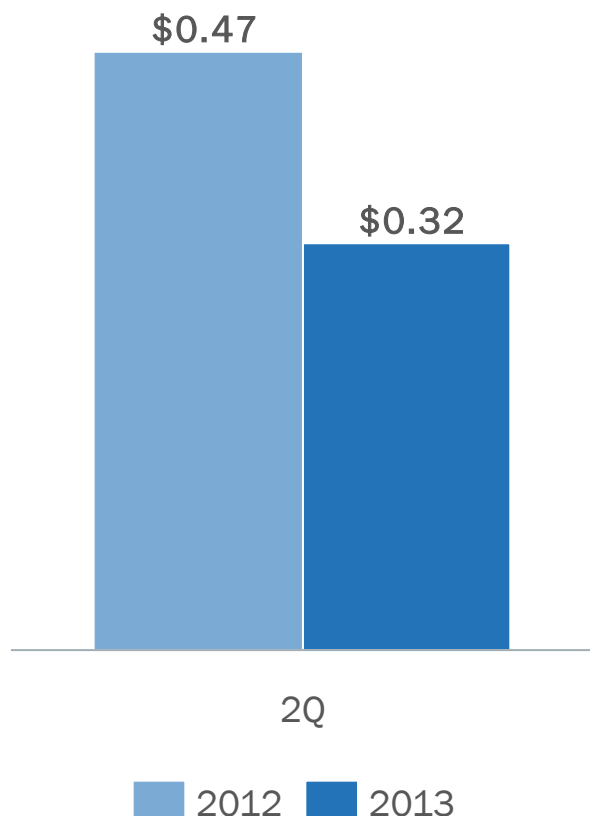


Expect 3Q 2013 earnings of \$0.60 - \$0.70/share and re-affirm full-year guidance range of \$2.35 - \$2.65/share

Numbers may not add due to rounding. SB9 = Senate Bill 9.

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

ExGen Operating EPS Contribution



Key Drivers – 2Q13 vs. 2Q12⁽¹⁾

- Lower RNF, primarily due to lower realized energy prices, lower capacity pricing and decreased load volumes: \$(0.15)
- Increased depreciation expense related to ongoing capital expenditures: \$(0.01)
- Lower O&M costs, primarily due to merger synergies, offset in part by timing of Salem nuclear refueling outage costs: \$0.01
- Lower income tax, primarily driven by AVSR investment tax credit benefits: \$0.01

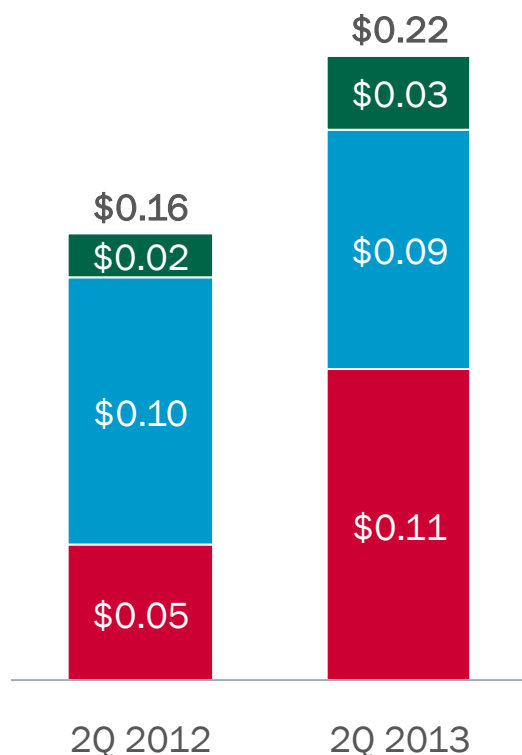
(excludes Salem and CENG)	<u>2Q12 Actual</u>	<u>2Q13 Actual</u>
Planned Refueling Outage Days	51	47
Non-refueling Outage Days	16	31
Nuclear Capacity Factor	93.4%	92.8%

RNF = Revenue Net Fuel.

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

Exelon Utilities Operating EPS Contribution

■ BGE ■ PECO ■ ComEd



Key Drivers – 2013 vs. 2012⁽¹⁾:

BGE (+0.01):

- Electric and gas distribution rates: \$0.02

PECO (-0.01):

- Higher O&M costs, primarily due to inflation: \$(0.01)
- Preferred securities redemption: \$(0.01)
- Lower income tax, primarily due to gas distribution tax repairs deduction: \$0.01

ComEd: (+0.06)

- Weather ⁽²⁾: \$(0.02)
- Higher distribution revenue due to higher allowed ROE⁽²⁾: \$0.01
- Impact of Senate Bill 9: \$0.01
- Discrete impacts of the May 2012 distribution formula rate order under EIMA⁽³⁾: \$0.07

Numbers may not add due to rounding.

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

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

(3) Energy Infrastructure Modernization Act

2013 Projected Sources and Uses of Cash

(\$ in millions)	BGE	ComEd	PECO	ExGen	Exelon ⁽⁶⁾	As of 1Q13	Delta
Beginning Cash Balance⁽¹⁾					1,575	1,575	–
Cash Flow from Operations ⁽²⁾	625	1,125	625	3,200	5,550	5,825	(275)
CapEx (excluding other items below):	(525)	(1,300)	(400)	(1,000)	(3,300)	(3,300)	–
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)	(125)	(25)
Wind	n/a	n/a	n/a	(25)	(25)	–	(25)
Solar	n/a	n/a	n/a	(550)	(550)	(550)	–
Upstream	n/a	n/a	n/a	(50)	(50)	(25)	(25)
Utility Smart Grid/Smart Meter	(125)	(150)	(175)	n/a	(450)	(400)	(50)
Net Financing (excluding Dividend):							
Debt Issuances	300	350	550	–	1,200	900	300
Debt Retirements ⁽⁴⁾	(400)	(250)	(500)	(450)	(1,600)	(1,400)	(200)
Project Finance/Federal Financing Bank Loan	n/a	n/a	n/a	1,025	1,025	1,025	–
Other ⁽⁵⁾	75	300	(100)	–	300	75	225
Ending Cash Balance⁽¹⁾					1,275	1,350	(75)

(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.

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

Exelon Generation Disclosures

June 30, 2013

Portfolio Management Strategy

Strategic Policy Alignment

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

Three-Year Ratable Hedging

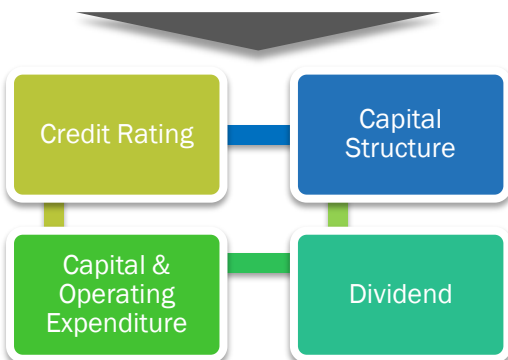
- Ensure stability in near-term cash flows and earnings
- Disciplined approach to hedging
- Tenor aligns with customer preferences and market liquidity
- Multiple channels to market that allow us to maximize margins
- Large open position in outer years to benefit from price upside

Bull / Bear Program

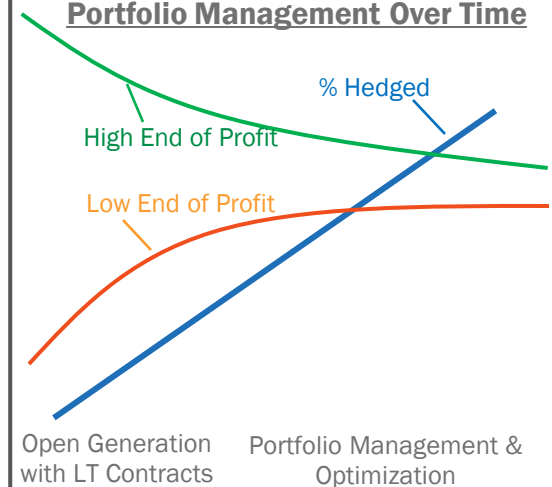
- Ability to exercise fundamental market views to create value within the ratable framework
- Modified timing of hedges versus purely ratable
- Cross-commodity hedging (heat rate positions, options, etc.)
- Delivery locations, regional and zonal spread relationships

Align Hedging & Financials

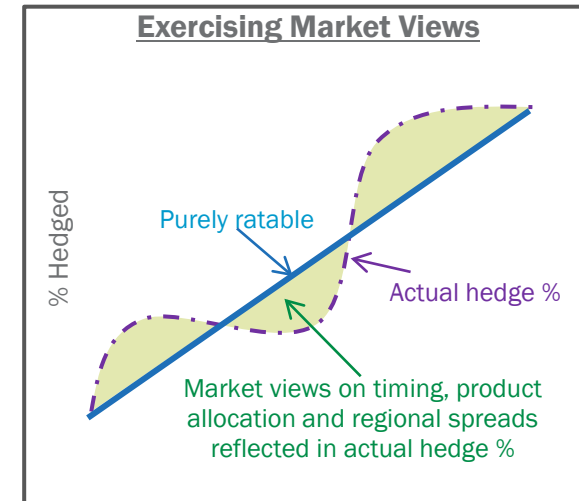
Establishing Minimum Hedge Targets



Portfolio Management Over Time



Exercising Market Views

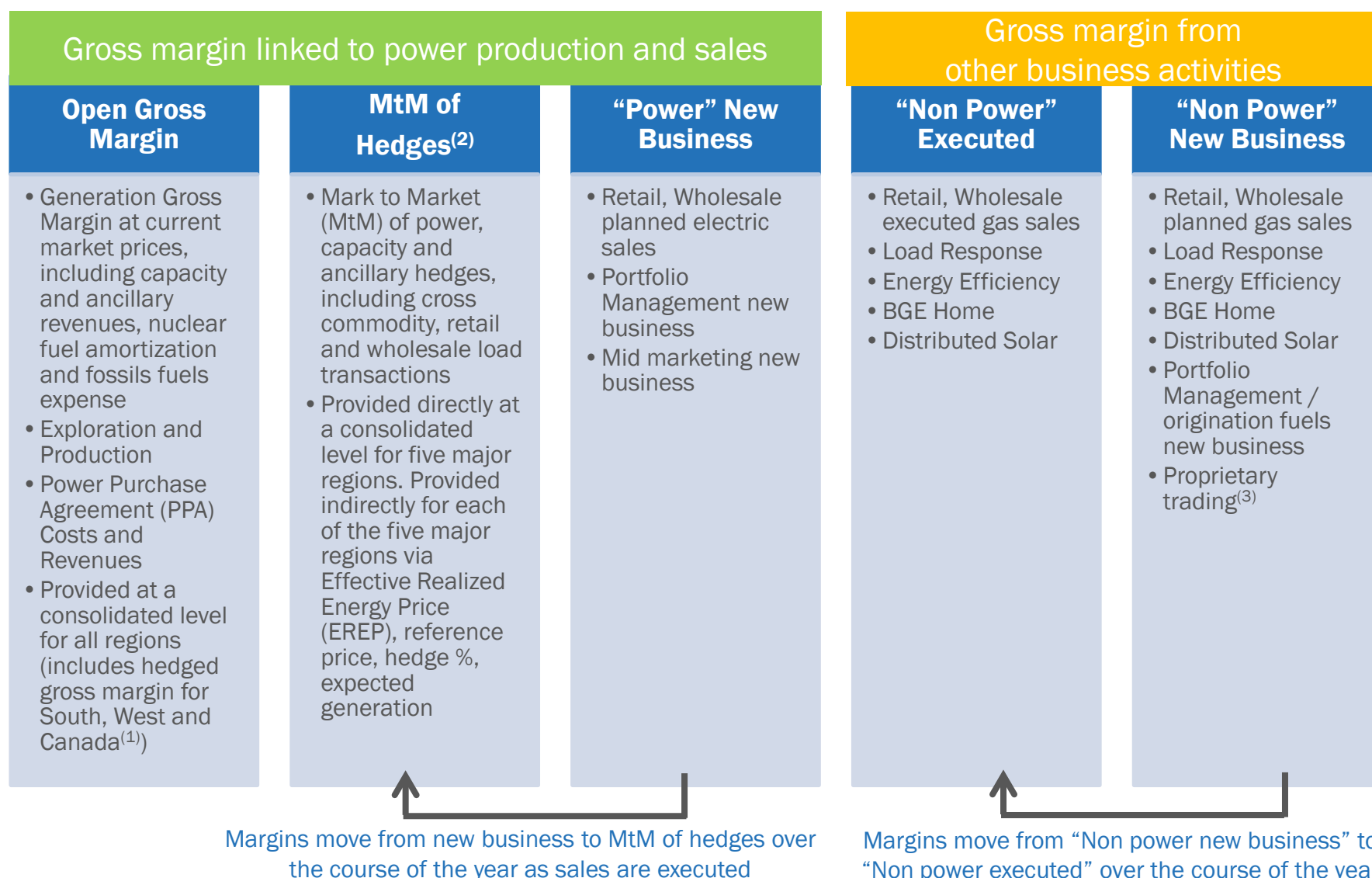


Protect Balance Sheet

Ensure Earnings Stability

Create Value

Components of Gross Margin Categories



(1) Hedged gross margins for South, West and 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
Open Gross Margin (including South, West & Canada hedged GM) ⁽³⁾	\$5,750	\$5,700	\$5,900
Mark to Market of Hedges ^(3,4)	\$1,450	\$850	\$400
Power New Business / To Go	\$200	\$550	\$750
Non-Power Margins Executed	\$350	\$150	\$50
Non-Power New Business / To Go ⁽⁵⁾	\$250	\$450	\$550
Total Gross Margin	\$8,000	\$7,700	\$7,650

Reference Prices ⁽⁶⁾	2013	2014	2015
Henry Hub Natural Gas (\$/MMbtu)	\$3.68	\$3.91	\$4.14
Midwest: NiHub ATC prices (\$/MWh)	\$31.00	\$29.90	\$31.04
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$37.76	\$37.26	\$38.53
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	\$4.93	\$7.90	\$8.76
New York: NY Zone A (\$/MWh)	\$36.82	\$35.40	\$36.22
New England: Mass Hub ATC Spark Spread (\$/MWh) <i>ALQN Gas, 7.5HR, \$0.50 VOM</i>	\$3.03	\$4.59	\$3.02

(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 June 30, 2013 market conditions.

ExGen Disclosures

Generation and Hedges	2013	2014	2015
<u>Exp. Gen (GWh) ⁽¹⁾</u>	215,500	214,400	207,600
Midwest	97,200	97,100	96,400
Mid-Atlantic ⁽²⁾	74,200	72,600	69,900
ERCOT	14,600	17,800	18,500
New York ⁽²⁾	14,100	12,100	9,300
New England	15,400	14,800	13,500
<u>% of Expected Generation Hedged ⁽³⁾</u>	96-99%	78-81%	41-44%
Midwest	95-98%	77-80%	38-41%
Mid-Atlantic ⁽²⁾	97-100%	82-85%	48-51%
ERCOT	102-105%	77-80%	34-37%
New York ⁽²⁾	96-99%	81-84%	45-48%
New England	97-100%	71-74%	23-26%
<u>Effective Realized Energy Price (\$/MWh) ⁽⁴⁾</u>			
Midwest	\$37.00	\$34.00	\$34.00
Mid-Atlantic ⁽²⁾	\$49.00	\$46.00	\$46.50
ERCOT ⁽⁵⁾	\$11.50	\$9.00	\$7.50
New York ⁽²⁾	\$32.00	\$37.00	\$44.00
New England ⁽⁵⁾	\$5.50	\$3.50	\$3.50

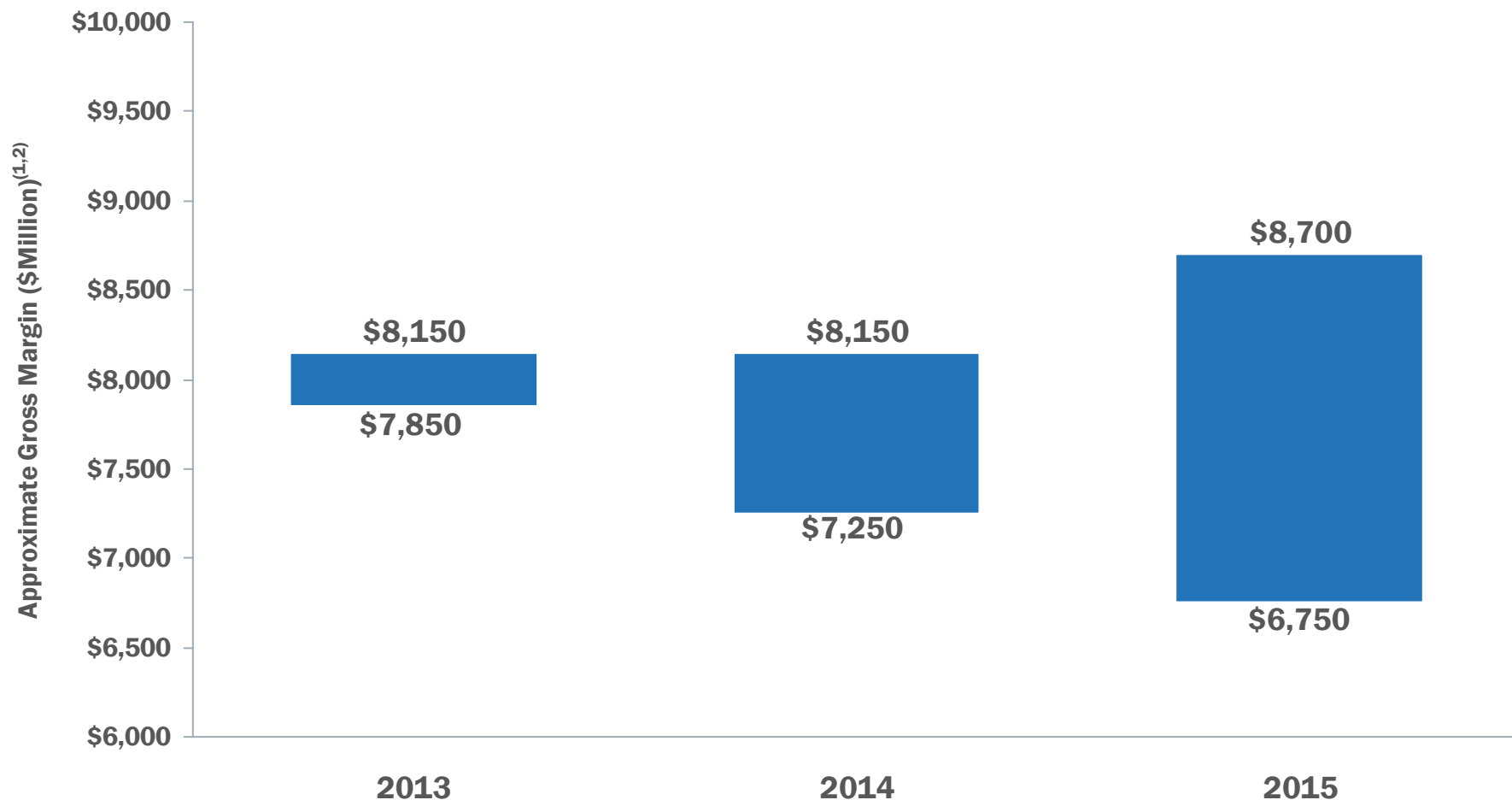
(1) Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted for capacity. Expected generation is based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 12 refueling outages in 2013 and 14 refueling outages in 2014 and 2015 at Exelon-operated nuclear plants, Salem and CENG. Expected generation assumes capacity factors of 93.8%, 93.8%, and 93.3% in 2013, 2014 and 2015 at Exelon-operated nuclear plants excluding Salem and CENG. These estimates of expected generation in 2014 and 2015 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)	2013	2014	2015
Henry Hub Natural Gas (\$/Mmbtu)			
+ \$1/Mmbtu	\$35	\$190	\$430
- \$1/Mmbtu	\$(20)	\$(130)	\$(370)
NiHub ATC Energy Price			
+ \$5/MWh	\$10	\$130	\$355
- \$5/MWh	\$(5)	\$(125)	\$(350)
PJM-W ATC Energy Price			
+ \$5/MWh	\$0	\$75	\$205
- \$5/MWh	\$5	\$(75)	\$(200)
NYPP Zone A ATC Energy Price			
+ \$5/MWh	\$0	\$10	\$25
- \$5/MWh	\$0	\$(10)	\$(25)
Nuclear Capacity Factor ⁽³⁾			
+/- 1%	+/- \$20	+/- \$40	+/- \$45

(1) Based on June 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 and 2015 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, 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

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Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	<div>← \$5.70 billion →</div>					
(B)	Expected Generation (TWh)	97.1	72.6	17.8	12.1	14.8	
(C)	Hedge % (assuming mid-point of range)	78.5%	83.5%	78.5%	82.5%	72.5%	
(D=B*C)	Hedged Volume (TWh)	76.2	60.6	14.0	10.0	10.7	
(E)	Effective Realized Energy Price (\$/MWh)	\$34.00	\$46.00	\$9.00	\$37.00	\$3.50	
(F)	Reference Price (\$/MWh)	\$29.90	\$37.26	\$7.90	\$35.40	\$4.59	
(G=E-F)	Difference (\$/MWh)	\$4.10	\$8.74	\$1.10	\$1.60	\$(1.09)	
(H=D*G)	Mark-to-market value of hedges (\$ million) ⁽¹⁾	\$315 million	\$530 million	\$15 million	\$15 million	\$(10) million	
(I=A+H)	Hedged Gross Margin (\$ million)	\$6,550 million					
(J)	Power New Business / To Go (\$ million)	\$550 million					
(K)	Non-Power Margins Executed (\$ million)	\$150 million					
(L)	Non- Power New Business / To Go (\$ million)	\$450 million					
(N=I+J+K+L)	Total Gross Margin	\$7,700 million					

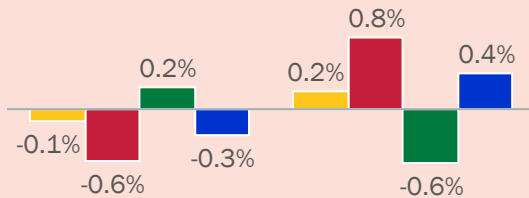
(1) Mark-to-market rounded to the nearest \$5 million.

Additional Disclosures

Exelon Utilities Weather-Normalized Load

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

ComEd



2012

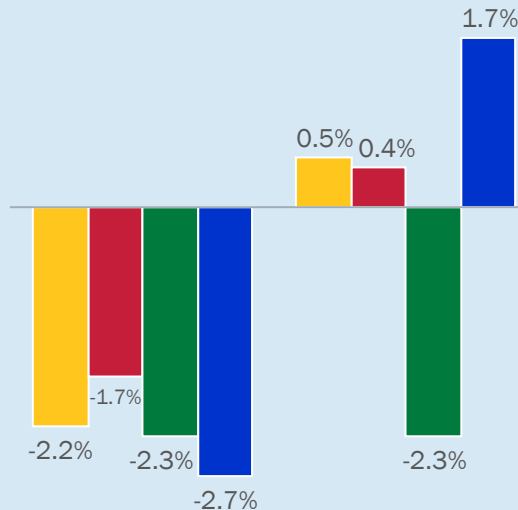
2013E

Chicago GMP 1.7%

Chicago Unemployment 9.4%

2013 load growth is similar to 2012, driven by improving economic conditions & positive residential load growth partially offset by energy efficiency

PECO



2012

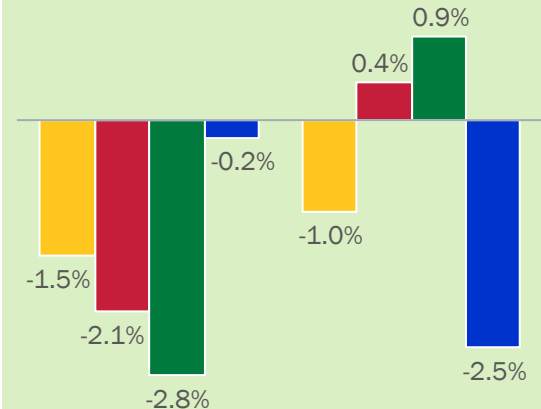
2013E

Philadelphia GMP 1.7%

Philadelphia Unemployment 7.9%

2013 load growth driven by oil refinery and economic conditions & customer growth, offset by energy efficiency

BGE



2012

2013E

Baltimore GMP 1.8%

Baltimore Unemployment 7.3%

2013 load growth largely driven by the idling of RG Steel and energy efficiency partially offset by improving economic conditions

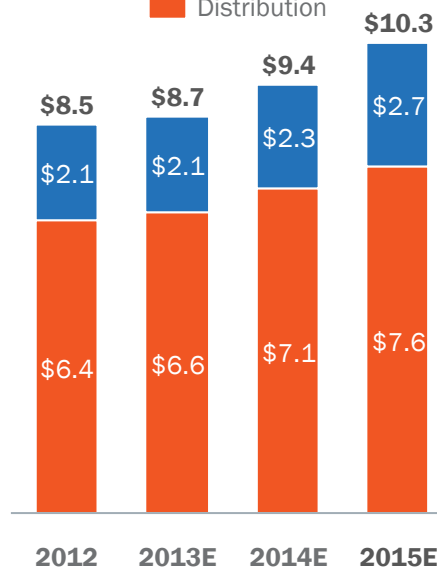
Notes: Data is not adjusted for leap year. Source of 2013 economic outlook data is Global Insight (May 2013). Assumes 2013 GDP of 1.8% and U.S unemployment of 7.6%. ComEd has the ROE collar as part of the distribution formula rate and BGE is decoupled which mitigates the load risk. QTD and YTD actual data can be found in earnings release tables. BGE amounts have been adjusted for unbilled / true-up load from prior quarters.

Exelon Utilities Rate Base and ROE Targets

(\$ in billions)

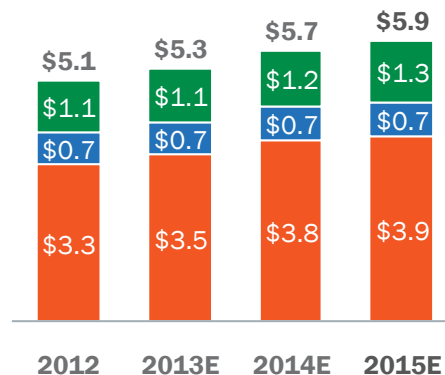


Transmission
Distribution



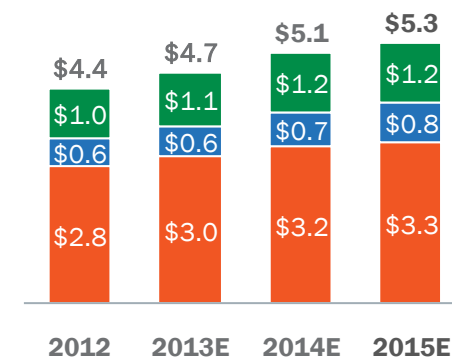
	2013E	Long-Term Target
Equity Ratio	~46%	~53% ⁽¹⁾
Earned ROE	8 -9%	Based on 30-yr. US Treasury ⁽²⁾

Gas Delivery
Electric Transmission
Electric Distribution



	2013E	Long-Term Target
Equity Ratio	~55%	~53%
Earned ROE	11.5 - 12.5%	≥10%

Gas Delivery
Electric Transmission
Electric Distribution



	2013E	Long-Term Target
Equity Ratio	~50%	~53% ⁽³⁾
Earned ROE	7-8%	≥10%

Continued investment in Utilities will provide stable earnings growth

All rate base amounts are presented as year-end rate base.

- (1) Exelon Utilities sets first quartile goals. The timing of the achievement of each goal will depend upon specific jurisdictional nuances to each company and how they impact the desired structure. The current distribution equity ratio for ComEd is ~46% and ComEd will look to grow this ratio over time. Currently, ComEd's Transmission capital ratio is limited to 55%.

- (2) 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.
- (3) 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% or if BGE is downgraded by two of three rating agencies.

ComEd May 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 12-0321) for calendar year 2013 were based on 2011 actual costs and 2012 projected net plant additions.
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	\$6,717 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. \$6,390 million - Reconciliation year (represents year-end rate base for 2012)
Revenue Requirement Increase	\$359M (\$165M is due to the 2012 reconciliation, \$194M 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.

Note: Disallowance of any items in the 2013 distribution formula rate filing could impact 2013 earnings in the form of a regulatory asset adjustment.

BGE Rate Case

Rate Case Request	Electric	Gas
Docket #	9326	
Test Year	August 2012 – July 2013	
Common Equity Ratio	49.8%	
Requested Returns	ROE: 10.5%; ROR: 7.75%	ROE: 10.35%; ROR: 7.67%
Rate Base (adjusted)	\$2.8B	\$1.1B
Revenue Requirement Increase	\$101.5M	\$29.7M
Proposed Distribution Increase as % of overall bill	3%	4%

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
- 10/15/13 – 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

2Q GAAP EPS Reconciliation

<u>Three Months Ended June 30, 2012</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>Other</u>	<u>Exelon</u>
2012 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.47	\$0.05	\$0.10	\$0.02	\$(0.02)	\$0.61
Mark-to-market impact of economic hedging activities	0.14	-	-	-	0.00	0.15
Unrealized losses related to NDT fund investments	(0.02)	-	-	-	-	(0.02)
Plant retirements and divestitures	0.00	-	-	-	-	0.00
Constellation merger and integration costs	(0.07)	-	(0.00)	(0.00)	(0.01)	(0.08)
Amortization of commodity contract intangibles	(0.33)	-	-	-	-	(0.33)
Amortization of the fair value of certain debt	0.00	-	-	-	-	0.00
Non-cash remeasurement of deferred income taxes	-	-	-	-	0.00	0.00
2Q 2012 GAAP Earnings (Loss) Per Share	\$0.19	\$0.05	\$0.09	\$0.01	\$(0.02)	\$0.33

<u>Three Months Ended June 30, 2013</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>Other</u>	<u>Exelon</u>
2013 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.32	\$0.11	\$0.09	\$0.03	\$(0.01)	\$0.53
Mark-to-market impact of economic hedging activities	0.30	-	-	-	(0.01)	0.30
Unrealized gains related to NDT fund investments	(0.03)	-	-	-	-	(0.03)
Constellation merger and integration costs	(0.01)	-	(0.00)	(0.00)	-	(0.02)
Amortization of commodity contract intangibles	(0.13)	-	-	-	-	(0.13)
Amortization of the fair value of certain debt	0.00	-	-	-	-	0.00
Long-lived asset impairment	(0.07)	-	-	-	(0.01)	(0.08)
2Q 2013 GAAP Earnings (Loss) Per Share	\$0.38	\$0.11	\$0.08	\$0.03	\$(0.03)	\$0.57

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, 2012	ExGen	ComEd	PECO	BGE	Other	Exelon
2012 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$1.03	\$0.17	\$0.23	\$0.04	\$(0.03)	\$1.44
Mark-to-market impact of economic hedging activities	0.20	-	-	-	0.01	0.21
Unrealized gains related to NDT fund investments	0.02	-	-	-	-	0.02
Plant retirements and divestitures	(0.01)	-	-	-	-	(0.01)
Constellation merger and integration costs	(0.13)	(0.00)	(0.01)	(0.00)	(0.09)	(0.23)
Maryland commitments	(0.03)	-	-	(0.11)	(0.16)	(0.29)
Amortization of commodity contract intangibles	(0.46)	-	-	-	-	(0.46)
Amortization of the fair value of certain debt	0.00	-	-	-	-	0.00
FERC Settlement	(0.22)	-	-	-	-	(0.22)
Non-cash remeasurement of deferred income taxes	0.02	-	-	-	0.14	0.16
Other acquisition costs	(0.00)	-	-	-	-	(0.00)
YTD 2012 GAAP Earnings (Loss) Per Share	\$0.43	\$0.17	\$0.22	(0.07)	\$(0.13)	\$0.62

Six Months Ended June 30, 2013	ExGen	ComEd	PECO	BGE	Other	Exelon
2013 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.71	\$0.22	\$0.23	\$0.11	\$(0.03)	\$1.23
Mark-to-market impact of economic hedging activities	0.02	-	-	-	0.00	0.02
Unrealized gains related to NDT fund investments	0.02	-	-	-	-	0.02
Plant retirements and divestitures	0.02	-	-	-	-	0.02
Constellation merger and integration costs	(0.05)	-	(0.00)	0.00	(0.00)	(0.05)
Amortization of commodity contract intangibles	(0.28)	-	-	-	-	(0.27)
Amortization of the fair value of certain debt	0.01	-	-	-	-	0.01
Remeasurement of like kind exchange tax position	-	(0.20)	-	-	(0.11)	(0.31)
Long lived asset impairment	(0.09)	-	-	-	(0.01)	(0.10)
YTD 2013 GAAP Earnings (Loss) Per Share	\$0.36	\$0.02	\$0.23	\$0.12	\$(0.15)	\$0.57

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 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
 - 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 an investment in a long term lease.
 - Other unusual items