

Earnings Conference Call 3rd Quarter 2013

October 30th, 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 Second 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.

3Q13 In Review

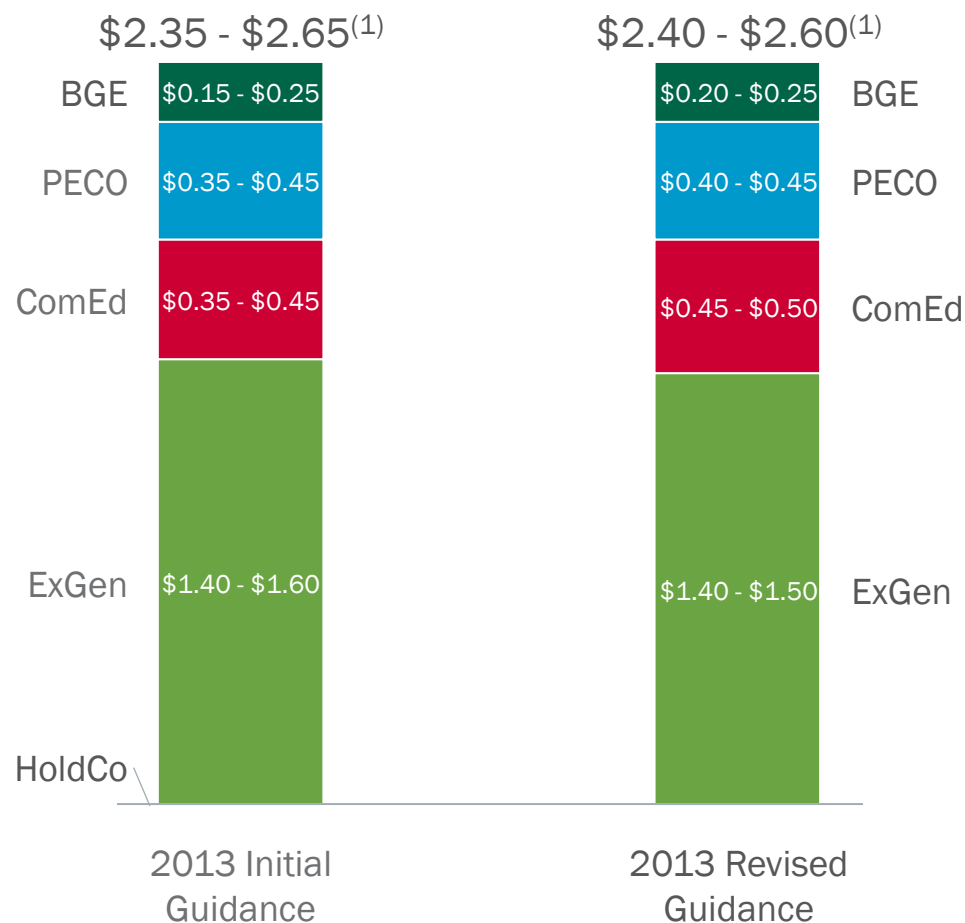
3Q Highlights

- Strong quarter with results higher than expected 3Q earnings of \$0.78/share
- Strong fleet operations
 - 94.8% nuclear capacity factor
 - 99.1% fossil and hydro dispatch match
- Continental Wind financing

Regulatory Update

- Rate cases for BGE and ComEd
- PJM stakeholder process on capacity markets
- LCAPP decision in New Jersey

Narrowing 2013 Full-Year Guidance



LCAPP = Long-Term Capacity Pilot Project

(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.

Exelon Generation: Gross Margin Update

	September 30, 2013			Change from June 30, 2013		
Gross Margin Category (\$M) ^{(1) (2)}	2013	2014	2015	2013	2014	2015
Open Gross Margin ⁽³⁾ (including South, West, Canada hedged gross margin)	5,600	5,650	5,800	(150)	(50)	(100)
Mark-to-Market of Hedges ^(3,4)	1,700	900	450	250	50	50
Power New Business / To Go	50	500	750	(150)	(50)	-
Non-Power Margins Executed	400	200	100	50	50	50
Non-Power New Business / To Go ⁽⁵⁾	200	400	500	(50)	(50)	(50)
Total Gross Margin	7,950	7,650	7,600	(50)	(50)	(50)

Key Changes in 3Q 2013

- Continue to execute behind ratable and utilize cross-commodity hedges as our fundamental view shows upside in 2015.
- **2013:** Reduction of \$50M due to lower expected margin from our Commercial group; offsets below gross margin make this a negligible impact to EPS
- **2014 & 2015:** \$50M reduction due to prices and a reduction in expected output from our wind assets.

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.

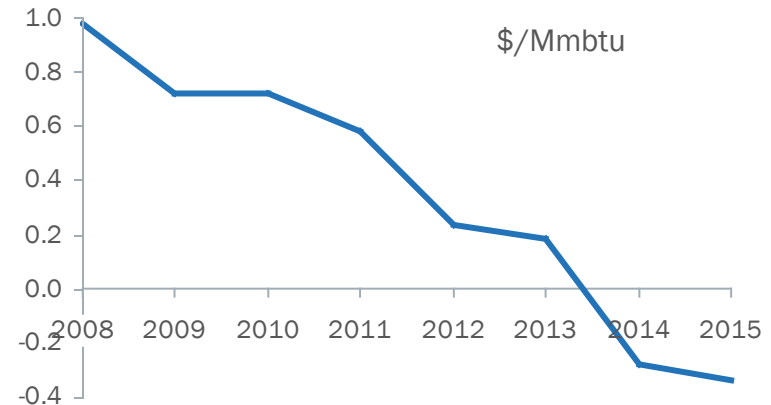
5) Any changes to new business estimates for our non-power business are presented as revenue less costs of sales.

Natural Gas Basis Impact on Portfolio Management

Structural Change That Has Developed Over Years; Should Stabilize Over the Coming Years

- Increases in Mid-Atlantic natural gas production and weak spot prices pressuring forward Mid-Atlantic basis prices
- We expect Mid-Atlantic basis prices will stabilize as infrastructure is put in place to export natural gas from the Mid-Atlantic production area
- Although Chicago city gate basis has also seen recent declines, PJM power price impact is smaller. We expect basis in the Midwest will not reach discounts seen in the East

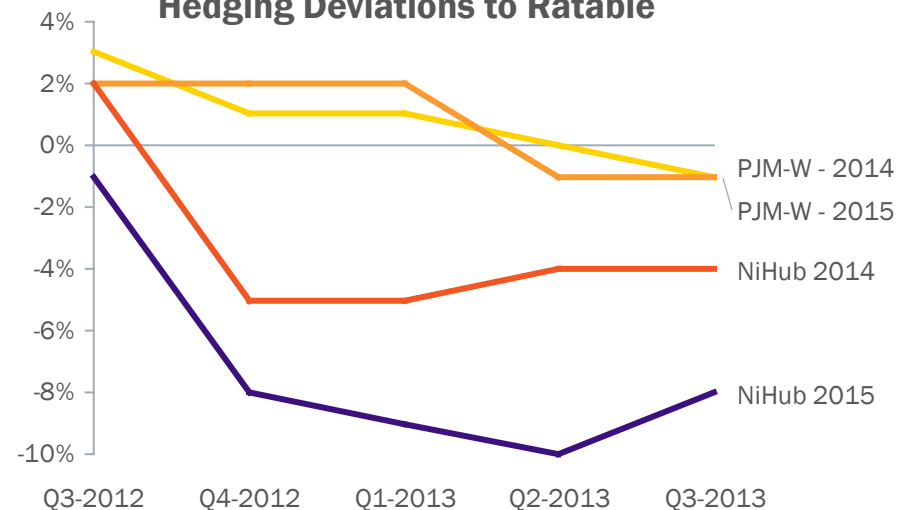
Realized and Forward Basis Prices (M3)



Dynamic Hedging to Address Natural Gas Basis Concerns

- Our hedging profile in PJM East has tracked at or ahead of ratable, limiting the impact of the basis move on our portfolio
- We continue to stay behind ratable in our PJM Midwest power portfolio due to our view that heat rates will expand

Hedging Deviations to Ratable



Key Financial Messages

- Delivered non-GAAP operating earnings⁽¹⁾ in 3Q of \$0.78/share; higher than guidance range provided of \$0.60 - \$0.70/share

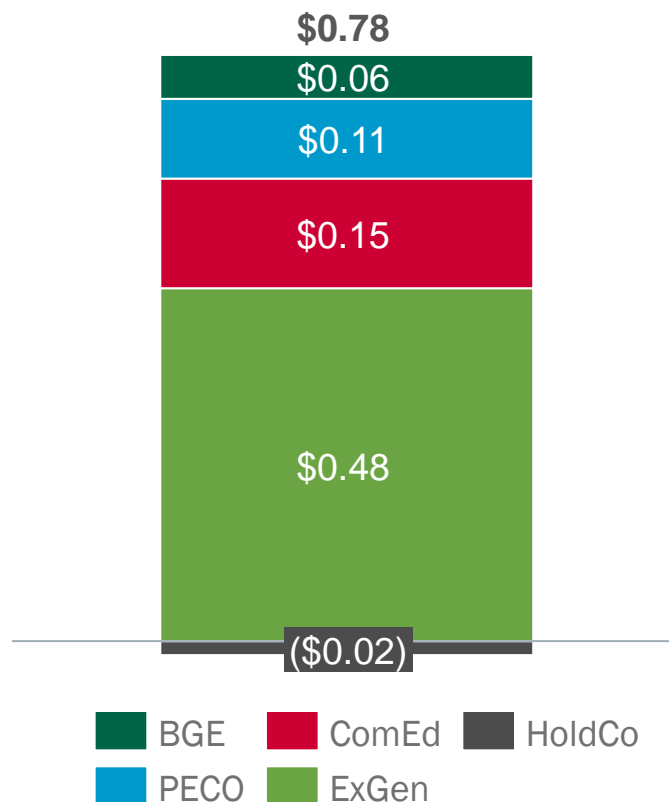
3Q 2013 vs. Guidance

- Higher earnings at utilities primarily driven by lower storm costs
- Higher ExGen earnings primarily driven by lower O&M

Full-Year 2013 Guidance

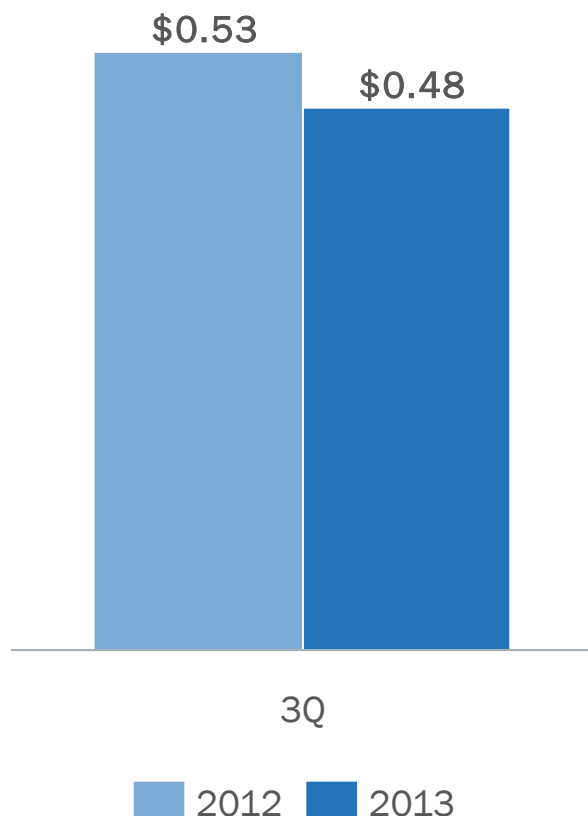
- Strong YTD performance reflected in raising the bottom of guidance range
- Gross margin reduction at ExGen
- Delay in AVSR tax credits

2013 3Q Results



(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 – 3Q13 vs. 3Q12⁽¹⁾

- Lower RNF, primarily due to lower realized energy prices, partially offset by higher capacity pricing and increased nuclear volumes: \$(0.18)
- Increased depreciation expense: \$(0.02)
- Higher Nuclear Decommissioning Trust (NDT) fund gains: \$0.02
- Lower O&M costs, primarily due to merger synergies: \$0.05
- Lower income and other taxes, primarily driven by AVSR investment tax credit benefits: \$0.06

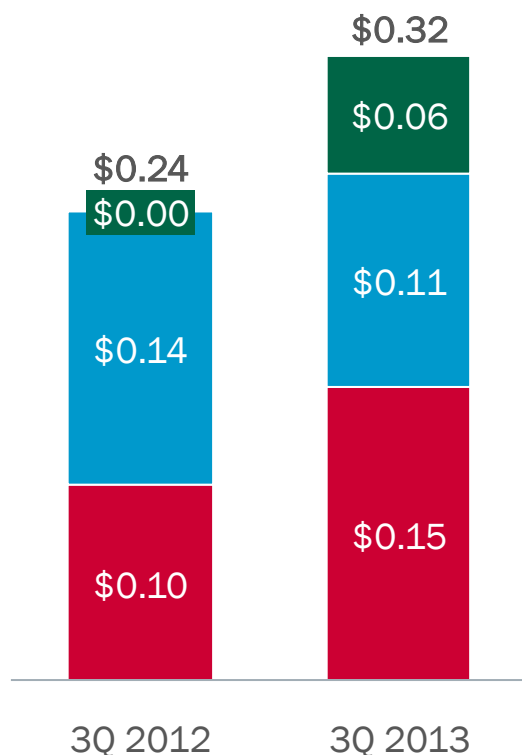
(excludes Salem and CENG)	3Q12 Actual	3Q13 Actual
Planned Refueling Outage Days	43	43
Non-refueling Outage Days	40	5
Nuclear Capacity Factor	90.7%	94.8%

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 – 3Q13 vs. 3Q12⁽¹⁾:

BGE (+\$0.06):

- Electric and gas distribution rates: \$0.02
- Decreased storm costs: \$0.03

PECO (-\$0.03):

- Weather: \$(0.02)
- Higher income tax, primarily due to gas distribution tax repairs deduction: \$(0.02)

ComEd (+\$0.05):

- Weather ⁽²⁾: \$(0.02)
- Customer mix⁽²⁾: \$0.01
- Higher distribution revenue due to increased recovery of costs and capital investments and higher allowed ROE⁽²⁾: \$0.05

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.

2013 Cash Flow Summary and Key Drivers

Projected Sources and Uses Summary⁽¹⁾

(\$ in millions)	BGE	ComEd	PECO	ExGen	Exelon ⁽²⁾	As of 2Q13	Delta
Beginning Year Cash Balance:					1,575	1,575	--
Cash Flow from Operations	575	1,075	650	3,550	5,775	5,550	225
Capital Expenditures	(625)	(1,450)	(550)	(2,725)	(5,450)	(5,525)	75
Net Financing (excluding items below):	(100)	100	50	(450)	(400)	(400)	-
Dividend					(1,250)	(1,250)	-
Project Finance	n/a	n/a	n/a	850	850	1,025	(175)
Other	75	350	(75)	(125)	325	300	25
Ending Year Cash Balance:					1,425	1,275	150

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

less capex of (\$5,450M)

- **\$75M lower projected Capex than 2Q13 Update**
 - \$50M AVSR construction delays
 - \$25M Lower investment at the utilities
 - (\$25M) Wind and Solar projects increased spend

Cash from operations of \$5,775M

- **\$225M higher than 2Q13 Update**
 - \$200M Primarily working capital changes at ExGen

and financing of (\$475M)

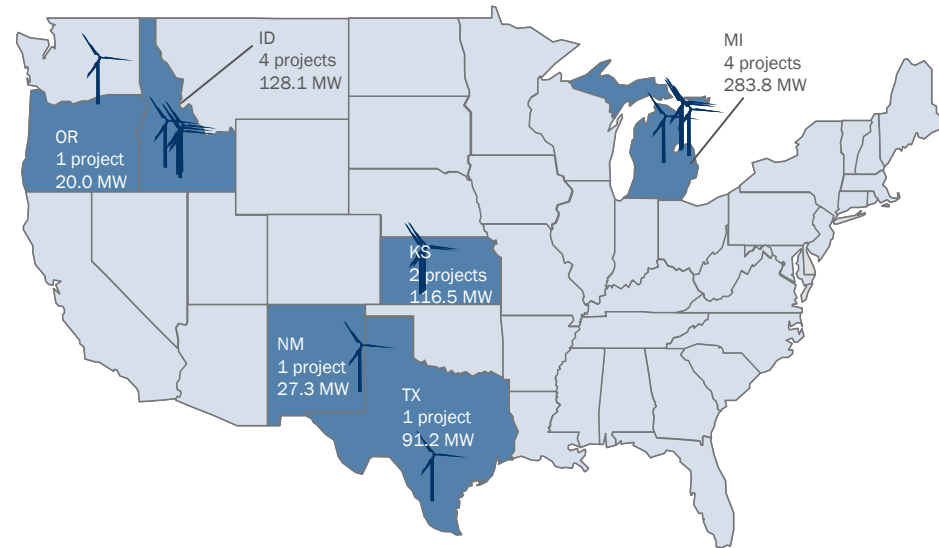
- **(\$150M) lower than 2Q13 Update**
 - (\$150M) Related to reduced AVSR DoE loan draw due to milestone delays
 - (\$25M) Reduced sizing of Continental Wind debt
 - \$50M Increase in projected year-end commercial paper at ComEd

(1) A more detailed view of the Sources and Uses table can be found on slide 22

Continental Wind Financing

- Issued \$613M of 20-year project finance debt with coupon of 6%
 - Non-recourse to parent
 - Financing based on long-term contracted cash flows of wind portfolio
- Largest ever domestic wind project finance transaction
- Debt rated as investment-grade by all three rating agencies
- Rating agencies treat debt as “non-recourse”

Financing backed by 667 MW wind portfolio across six states



Project financing is an attractive vehicle to grow the business in a credit supportive manner

Exelon Generation Disclosures

September 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

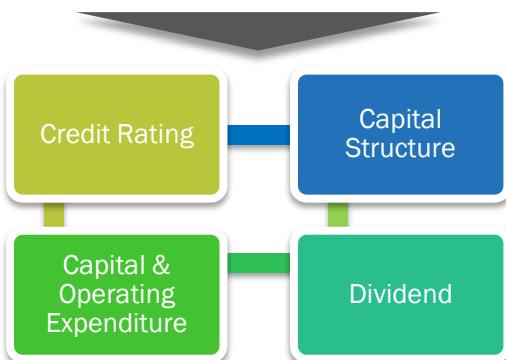
- Ensure stability in near-term cash flows and earnings
- Disciplined approach to hedging
- Tenor aligns with customer preferences and market liquidity
- Multiple channels to market that allow us to maximize margins
- Large open position in outer years to benefit from price upside

Bull / Bear Program

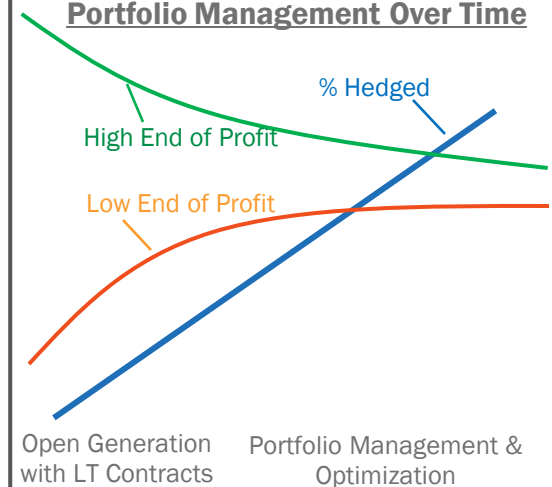
- Ability to exercise fundamental market views to create value within the ratable framework
- Modified timing of hedges versus purely ratable
- Cross-commodity hedging (heat rate positions, options, etc.)
- Delivery locations, regional and zonal spread relationships

Align Hedging & Financials

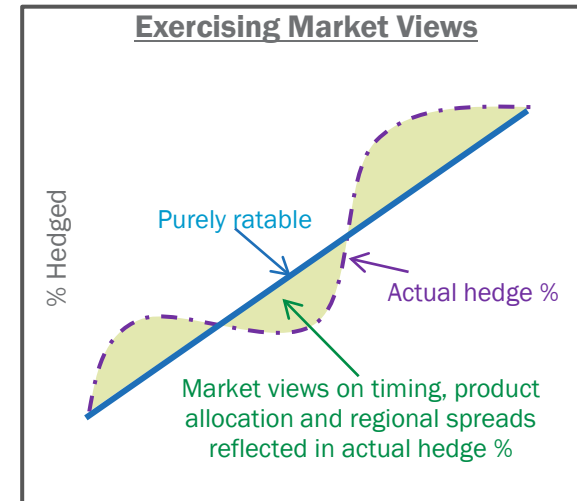
Establishing Minimum Hedge Targets



Portfolio Management Over Time



Exercising Market Views

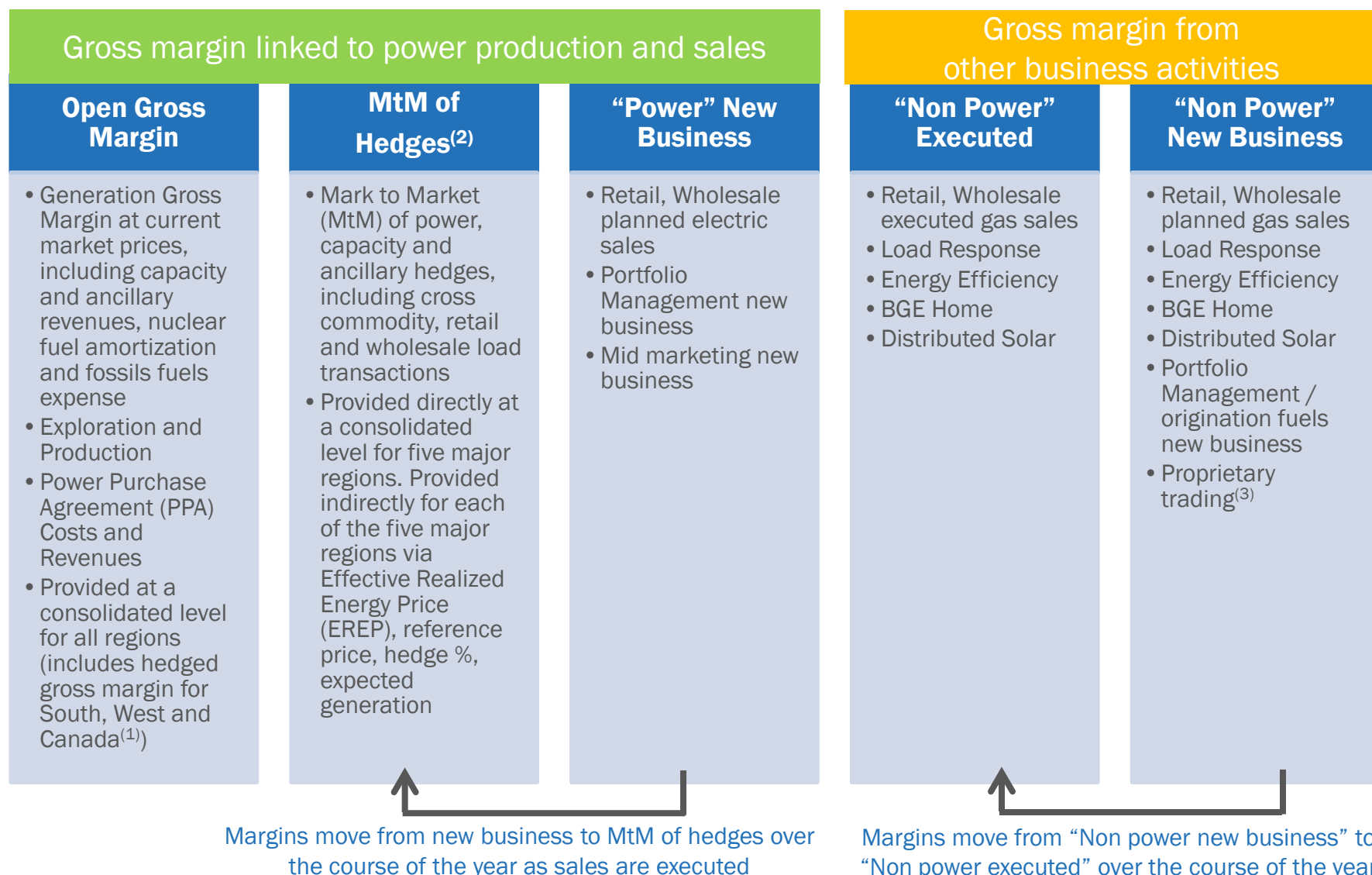


Protect Balance Sheet

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⁾	5,600	5,650	5,800
Mark to Market of Hedges ^(3,4)	1,700	900	450
Power New Business / To Go	50	500	750
Non-Power Margins Executed	400	200	100
Non-Power New Business / To Go ⁽⁵⁾	200	400	500
Total Gross Margin	7,950	7,650	7,600

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

(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
<u>Exp. Gen (GWh) ⁽¹⁾</u>	214,700	215,500	209,400
Midwest	97,200	96,900	96,400
Mid-Atlantic ⁽²⁾	74,500	73,600	70,100
ERCOT	13,200	17,800	19,600
New York ⁽²⁾	14,000	12,500	9,300
New England	15,800	14,700	14,000
<u>% of Expected Generation Hedged ⁽³⁾</u>	97-100%	84-87%	48-51%
Midwest	97-100%	85-88%	47-50%
Mid-Atlantic ⁽²⁾	97-100%	90-93%	56-59%
ERCOT	92-95%	81-84%	38-41%
New York ⁽²⁾	99-101%	87-90%	54-57%
New England	94-97%	49-52%	22-25%
<u>Effective Realized Energy Price (\$/MWh) ⁽⁴⁾</u>			
Midwest	\$37.00	\$33.50	\$33.00
Mid-Atlantic ⁽²⁾	\$49.00	\$45.00	\$45.00
ERCOT ⁽⁵⁾	\$24.00	\$11.00	\$9.50
New York ⁽²⁾	\$32.00	\$37.00	\$42.50
New England ⁽⁵⁾	\$6.00	\$3.50	\$2.00

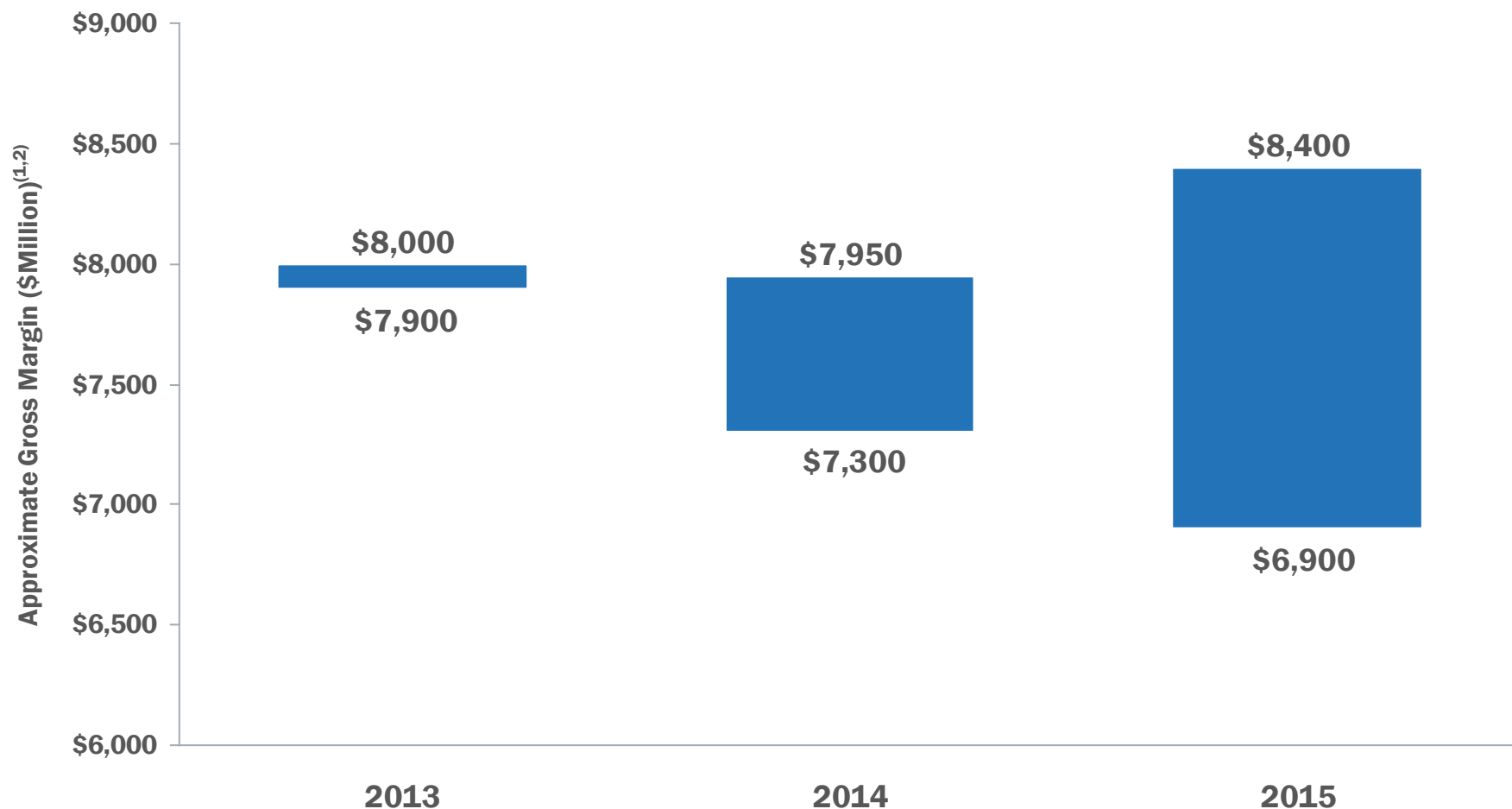
(1) Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted for capacity. Expected generation is based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, 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 94.1%, 93.7%, 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	\$10	\$110	\$370
- \$1/Mmbtu	\$0	\$(45)	\$(305)
NiHub ATC Energy Price			
+ \$5/MWh	\$0	\$65	\$325
- \$5/MWh	\$0	\$(60)	\$(325)
PJM-W ATC Energy Price			
+ \$5/MWh	\$0	\$35	\$175
- \$5/MWh	\$0	\$(35)	\$(170)
NYPP Zone A ATC Energy Price			
+ \$5/MWh	\$0	\$5	\$20
- \$5/MWh	\$0	\$(10)	\$(20)
Nuclear Capacity Factor ⁽³⁾			
+/- 1%	+/- \$10	+/- \$40	+/- \$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 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 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>← \$5.65 billion →</div>					
(B)	Expected Generation (TWh)	96.9	73.6	17.8	12.5	14.7	
(C)	Hedge % (assuming mid-point of range)	85.5%	91.5%	82.5%	88.5%	50.5%	
(D=B*C)	Hedged Volume (TWh)	82.8	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⁾	\$270 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					

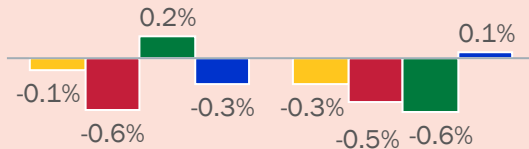
(1) Mark-to-market rounded to the nearest \$5 million.

Additional Disclosures

Exelon Utilities Weather-Normalized Load

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

ComEd



2012

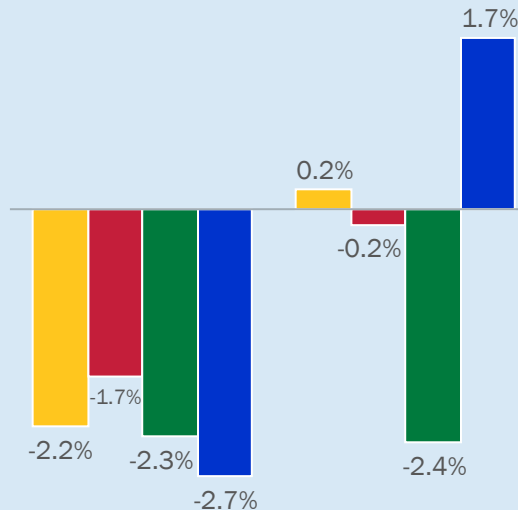
2013E

Chicago GMP 1.2%

Chicago Unemployment 9.4%

2013 load growth is similar to 2012, driven by slowly improving economic conditions and partially offset by energy efficiency.

PECO



2012

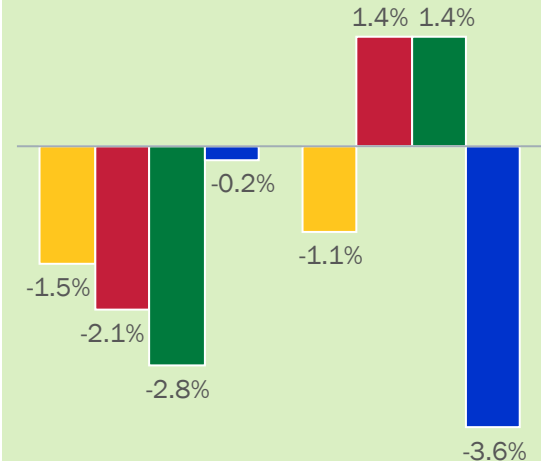
2013E

Philadelphia GMP 1.0%

Philadelphia Unemployment 8.3%

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 7.5%

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 (August 2013). Assumes 2013 GDP of 1.5% and U.S unemployment of 7.3%.

ComEd has the ROE collar as part of the distribution formula rate and BGE is decoupled which mitigates the load risk. QTD and YTD actual data can be found in earnings release tables.

BGE amounts have been adjusted for unbilled / true-up load from prior quarters.

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.

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

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 – 11/1/13: 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

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.

3Q GAAP EPS Reconciliation

<u>Three Months Ended September 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	\$0.54	\$0.11	\$0.14	\$0.00	\$(0.01)	\$0.77
Mark-to-market impact of economic hedging activities	0.01	-	-	-	0.01	0.02
Unrealized losses related to NDT fund investments	0.04	-	-	-	-	0.04
Plant retirements and divestitures	(0.22)	-	-	-	-	(0.22)
Asset retirement obligation	(0.01)	-	-	-	-	(0.01)
Constellation merger and integration costs	(0.04)	-	-	-	-	(0.04)
Amortization of commodity contract intangibles	(0.21)	-	-	-	-	(0.21)
3Q 2012 GAAP Earnings (Loss) Per Share	\$0.11	\$0.11	\$0.14	\$0.00	\$0.00	\$0.35

<u>Three Months Ended September 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	\$0.47	\$0.15	\$0.11	\$0.06	\$(0.02)	\$0.78
Mark-to-market impact of economic hedging activities	0.18	-	-	-	-	0.17
Unrealized gains related to NDT fund investments	0.03	-	-	-	-	0.03
Asset retirement obligation	(0.01)	-	-	-	-	(0.01)
Constellation merger and integration costs	(0.02)	-	(0.00)	-	-	(0.03)
Amortization of commodity contract intangibles	(0.05)	-	-	-	-	(0.05)
Long-lived asset impairment	(0.03)	-	-	-	-	(0.03)
3Q 2013 GAAP Earnings (Loss) Per Share	\$0.57	\$0.15	\$0.11	\$0.06	\$(0.02)	\$0.86

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

3Q YTD GAAP EPS Reconciliation

<u>Nine Months Ended September 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	\$1.57	\$0.27	\$0.38	\$0.03	\$(0.05)	\$2.21
Mark-to-market impact of economic hedging activities	0.21	-	-	-	0.02	0.23
Unrealized gains related to NDT fund investments	0.07	-	-	-	-	0.07
Plant retirements and divestitures	(0.25)	-	-	-	-	(0.25)
Asset retirement obligation	(0.01)	-	-	-	-	(0.01)
Constellation merger and integration costs	(0.16)	-	(0.01)	-	(0.08)	(0.26)
Maryland commitments	(0.03)	-	-	(0.10)	(0.15)	(0.28)
Amortization of commodity contract intangibles	(0.68)	-	-	-	-	(0.68)
Amortization of the fair value of certain debt	0.01	-	-	-	-	0.01
FERC Settlement	(0.22)	-	-	-	-	(0.22)
Reassessment of deferred income taxes	0.02	-	-	-	0.13	0.15
YTD 2012 GAAP Earnings (Loss) Per Share	\$0.53	\$0.27	\$0.37	(0.07)	\$(0.13)	\$0.97

<u>Nine Months Ended September 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	\$1.18	\$0.36	\$0.34	\$0.16	\$(0.06)	\$2.00
Mark-to-market impact of economic hedging activities	0.20	-	-	-	(0.00)	0.21
Unrealized gains related to NDT fund investments	0.04	-	-	-	-	0.04
Plant retirements and divestitures	0.02	-	-	-	-	0.01
Asset retirement obligation	(0.01)	-	-	-	-	(0.01)
Constellation merger and integration costs	(0.07)	-	(0.01)	0.00	(0.00)	(0.08)
Amortization of commodity contract intangibles	(0.32)	-	-	-	-	(0.32)
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	(0.12)	-	-	-	(0.01)	(0.13)
YTD 2013 GAAP Earnings (Loss) Per Share	\$0.93	\$0.16	\$0.33	\$0.17	\$(0.18)	\$1.42

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
 - Financial impacts associated with the increase in certain decommissioning 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