

Earnings Conference Call 3rd Quarter 2012

November 1st, 2012



Cautionary Statements Regarding Forward-Looking Information

ZECJ-FIN-21

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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 2011 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 18; (2) Constellation Energy Group's 2011 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 12; (3) the Registrant's Second Quarter 2012 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 16; and (4) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this presentation. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

3Q Update

- **Strong 3Q financial performance**

- Operating earnings of \$0.77/share, above \$0.65 - \$0.75/share guidance range

- **Expect 2012 full year operating earnings of \$2.75 - \$2.95/share**

- Guidance increase driven by year-to-date financial performance and ICC Rehearing Order

- **Merger is working**

- Expect to achieve \$170M in merger related O&M synergies for 2012 and \$550M run rate synergies starting in 2014
 - Includes additional \$50M of O&M reductions starting in 2014
- Expect to close Maryland asset divestiture in 4Q 2012
- Benefiting from well-matched generation and load footprint
- Integrated operations are seamless

Market Fundamentals: Upside in Power Prices

Current & Near Term (2012/2013)

Market Dynamics

- No major impact on power prices from CSAPR⁽¹⁾ being vacated
- ~15 GW of retirements expected⁽²⁾
- Volatile heat rates in 2012 due to volatile gas prices and weather

Portfolio Impact⁽³⁾

- Fully hedged in 2012 and greater than 85% hedged in 2013

Medium & Long Term (2014+)

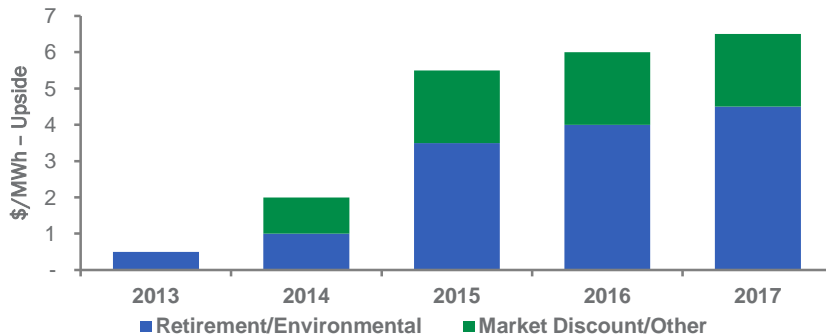
Market Dynamics

- Low gas prices and MATS⁽⁴⁾ rule are major drivers of coal retirements
- ~42 GW of coal retirements expected⁽²⁾. Includes ~27 GW of retirements in 2014-2016
- Internal view of \$3-6/MWh upside in power prices not currently reflected in forward prices

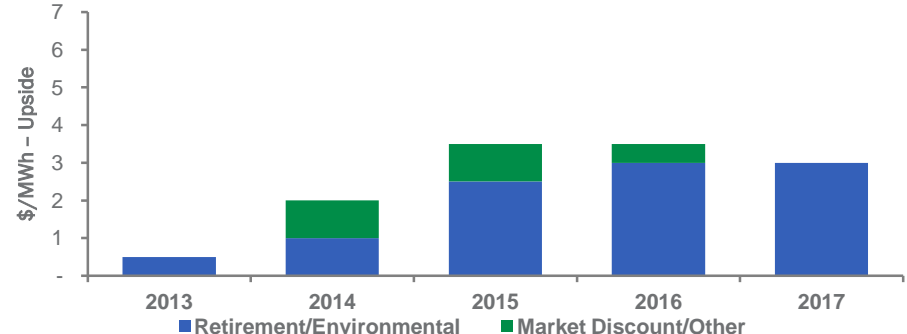
Portfolio Impact⁽³⁾

- Over 40% open in 2014, over 75% open in 2015 and mostly open in 2016 and beyond
- Use of cross-commodity hedges leaves even more upside to heat rate expansion

PJM NiHub ATC Power (Forecast vs Market)⁽⁵⁾



PJM West Hub ATC Power (Forecast vs Market)⁽⁵⁾



Expected upside is the result of plant retirements, higher operating costs for compliance with environmental standards and a continued disconnect between heat rates and gas prices

(1) Cross State Air Pollution Rule.

(2) Retirements estimate is for the Eastern Interconnect as per Exelon's internal projections.

(3) Portfolio hedge percentages are shown as of 9/30/12.

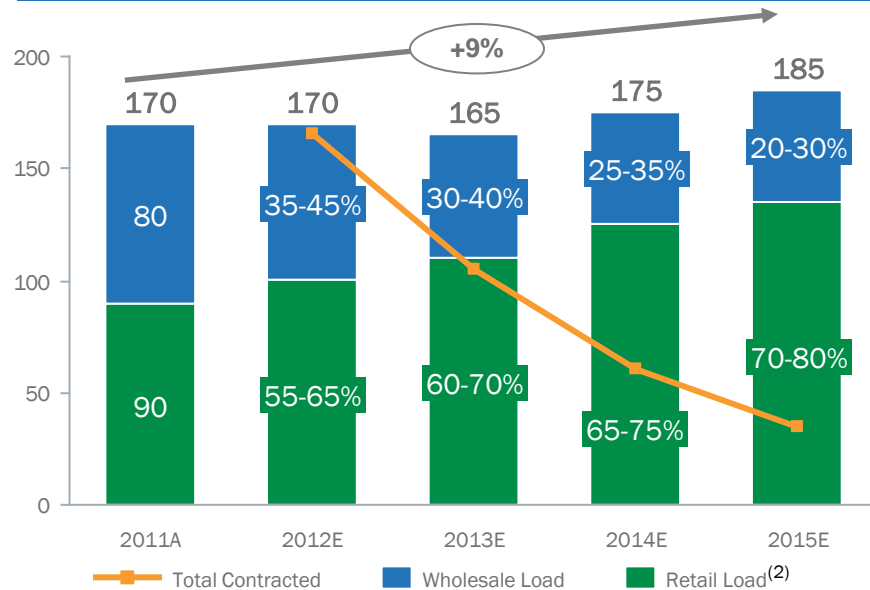
(4) Mercury and Air Toxics Standards.

(5) Upside figures are rounded to the nearest \$0.50/MWh and are based on 9/30/12 pricing.

Note: Internal views assume normal weather patterns.

Exelon Generation: Load Serving Update

Retail & Wholesale Load (TWh)⁽¹⁾



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

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

Strategy

- Serve new customers as existing markets grow and new markets open
 - Retail expected to grow at ~11% CAGR for 2011-2015
 - Wholesale expected to remain static starting in 2013
- Improve market share in existing markets
- Cross sell suite of products to existing customers to create higher retention
- Leverage operational efficiency and national footprint

Retail Landscape

- Expected load growth of 1% across the U.S.
- Switched market expected to grow by approximately 11% in C&I from 2011 to 2015
- Switched market expected to grow by approximately 22% in residential from 2011 to 2015

Execution

- Recently, the market has been impacted by increased competition and aggressive pricing
- Our disciplined approach to pricing has led to a reduction in expected volumes and margins
- Various channels to market are available to optimize our generation

Exelon Generation: Gross Margin Update

	September 30, 2012				June 30, 2012		
Gross Margin Category (\$M) ⁽¹⁾	2012 ⁽²⁾	2013	2014	2015	2012 ⁽²⁾	2013	2014
Open Gross Margin ^(2,3,4) (including South, West, Canada hedged gross margin)	\$4,500	\$5,750	\$6,050	\$6,200	\$4,450	\$5,400	\$5,850
Mark-to-Market of Hedges ^(4,5)	\$3,200	\$1,350	\$500	\$250	\$3,100	\$1,650	\$600
Power New Business / To Go	\$50	\$500	\$750	\$950	\$100	\$550	\$850
Non-Power Margins Executed	\$300	\$150	\$100	\$50	\$250	\$100	\$100
Non-Power New Business / To Go	\$100	\$450	\$500	\$550	\$150	\$500	\$500
Total Gross Margin	\$8,150	\$8,200	\$7,900	\$8,000	\$8,050	\$8,200	\$7,900

Key Highlights of 3Q 2012

Forward power market prices experienced sizeable swings through the 3rd quarter

- We have optimized our hedging during this volatile period and are back on ratable
- Expect to employ a variety of strategies to leverage ourselves for expected upside
 - Position our regional portfolios within our Bull/Bear framework to best take advantage of various market anomalies
 - Further utilize cross-commodity hedges to protect against further downside in the natural gas market, while remaining open to our view that heat rates will expand

September 30th gross margins reflect our new expectations for wholesale and retail load volumes and margins

Our forward view continues to be that there is upside in power prices and our fleet is leveraged for that upside

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

(2) Stub period calculated by excluding Jan 2012 through mid-March 2012 for Constellation only.

(3) Excludes Maryland assets to be divested.

(4) Includes CENG Joint Venture.

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

Exelon's Financial Priorities & Actions

Priorities

- **Number one priority is to maintain investment grade across all registrants**
- **Second priority is return value to our shareholders through our dividend**
- **Third priority is investing in sustainable growth projects**



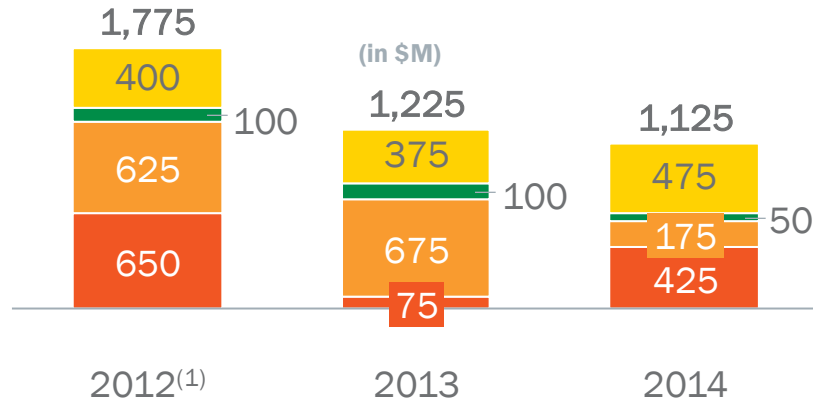
Actions

- **Significant reduction in capital expenditures in 2013-2015**
 - Deferral of Limerick and LaSalle uprates to allow for power market recovery
 - Removed unidentified renewable capex
- **Further reduction in O&M of \$50M starting in 2014**

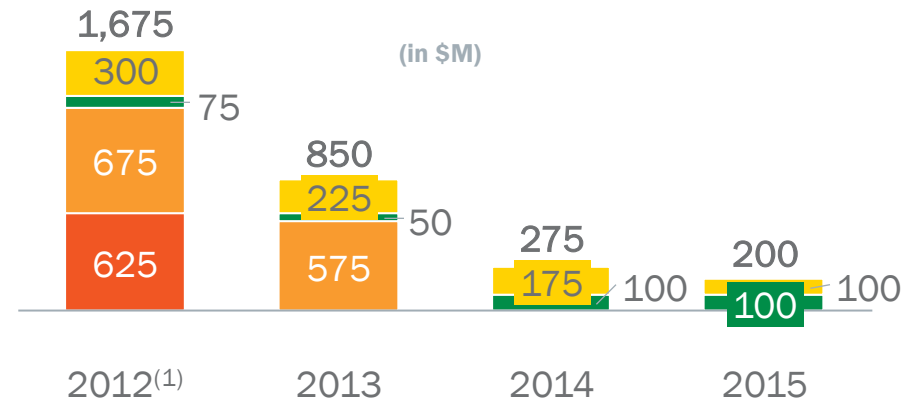
Taking action to meet our top priorities through changes in spending plans and timing of investments to align with a power market recovery

Updating Exelon Generation Growth Capital Spend

ExGen Growth Capex (June 2012 Analyst Day)



ExGen Growth Capex (3Q 2012)



■ Nuclear Upgrades ■ Upstream Gas ■ Solar ■ Wind

■ Nuclear Upgrades ■ Upstream Gas ■ Solar ■ Wind

- **Nuclear uprates capex reduced by \$1,025M in 2012-2015**
 - Deferred Limerick EPU project completion from 2017 to 2021
 - Deferred LaSalle EPU project completion another two years from 2018 to 2020
- **Eliminated unidentified wind and solar capex of \$1,250M in 2013-2015**
 - Renewable projects will be pursued in the future if they meet our internal parameters
- **Peach Bottom EPU project to be completed as planned**
 - Strong returns (well above 10% IRR on a go forward basis) under range of different pricing scenarios
 - Invested \$55M to date, at ownership level
 - At ownership, project is smallest of the EPUs with total capex of \$415M through 2016; limited impact on balance sheet
- **Maintained Upstream Gas spend**
 - Strong returns (>12% IRR)
 - Off-balance sheet financing

(1) 2012 CapEx includes CEG from merger close date.

EPU = Extended Power Upgrade

ComEd Regulatory Update

- ICC Rehearing Order (issued 10/3/12) on pension asset, interest rate on cost reconciliation and average vs. year-end rate base
 - Reversed decision on pension asset by granting ComEd recovery on the cost of funding its pension
 - Upheld the decision to use average rate base (vs. ComEd's position of using year end rate base)
 - Revised the decision on interest on reconciliation balances, granting a rate equal to the short term debt rate (vs. ComEd's view of using WACC rate)
- As a result of the order, ComEd has deferred \$450 million of capital expenditures from 2012-2014 to 2015 and beyond
- Filed a notice of appeal on 10/4/12 to challenge the interest rate on reconciliation and average rate base issues plus other items lost in May 2012 order

3Q 2012 Operating Results

- Delivered non-GAAP operating earnings in 3Q of \$0.77/share⁽¹⁾, above guidance expectations, primarily due to:

ExGen

- Portfolio optimization of \$0.07/share
- Lower than expected nuclear volume of \$(0.03)/share

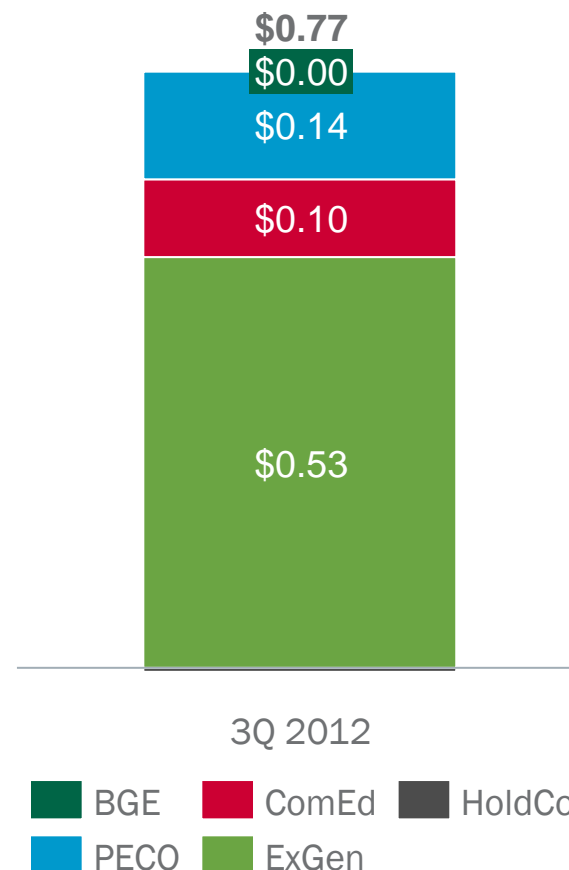
ComEd

- Favorable weather of \$0.01/share

PECO

- Favorable weather of \$0.01/share
- Higher than expected benefit of \$0.02/share from gas distribution tax repairs deduction

2012 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.

2012 Projected Sources and Uses of Cash

(\$ in Millions)



Beginning Cash Balance⁽¹⁾					\$550
Cash acquired from Constellation ⁽²⁾	150	n/a	n/a	1,375	1,650
Cash Flow from Operations ⁽³⁾	250	1,175	900	3,475	5,825
CapEx (excluding other items below):	(425)	(1,225)	(350)	(975)	(3,050)
Nuclear Fuel	n/a	n/a	n/a	(1,150)	(1,150)
Dividend ⁽⁴⁾					(1,725)
Nuclear Upgrades	n/a	n/a	n/a	(300)	(300)
Wind	n/a	n/a	n/a	(625)	(625)
Solar	n/a	n/a	n/a	(675)	(675)
Upstream	n/a	n/a	n/a	(75)	(75)
Utility Smart Grid/Smart Meter	(75)	(50)	(75)	n/a	(200)
Net Financing (excluding Dividend):					
Debt Issuances ⁽⁵⁾	250	350	350	775	1,725
Debt Retirements	(175)	(450)	(375)	(125)	(1,125)
Project Finance/Federal Financing Bank Loan	n/a	n/a	n/a	375	375
Other ⁽⁶⁾	--	25	(25)	--	(100)
Ending Cash Balance⁽¹⁾					\$1,100

(1) Exelon beginning cash balance as of 12/31/11. Excludes counterparty collateral activity.

(2) Includes \$675 million of Constellation net collateral paid to counterparties prior to merger completion.

(3) Cash Flow from Operations primarily includes net cash flows provided by operating activities, estimated proceeds from Maryland clean coal fleet divestitures and net cash flows used in investing activities other than capital expenditures.

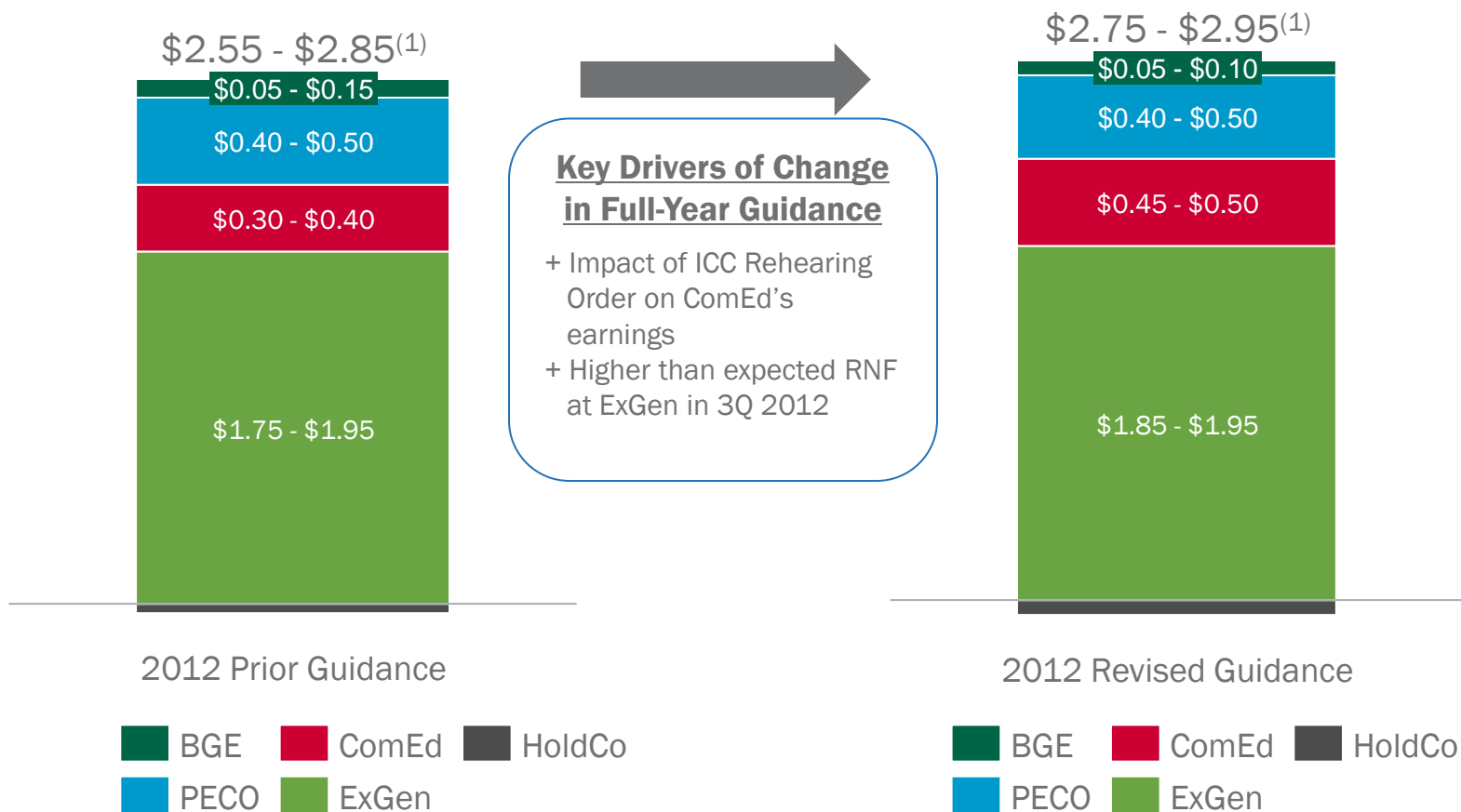
(4) Dividends are subject to declaration by the Board of Directors.

(5) Excludes PECO's \$225 million Accounts Receivable (A/R) Agreement with Bank of Tokyo. PECO's A/R Agreement was extended in accordance with its terms through August 30, 2013.

(6) "Other" includes proceeds from options and expected changes in short-term debt.

(7) Includes cash flow activity from Holding Company, eliminations, and other corporate entities. Represents Constellation cash flows from merger close through December 31, 2012.

2012 Earnings Guidance



Updated FY 2012 operating earnings to \$2.75 - \$2.95/share

(1) 2012 guidance includes Constellation Energy and BGE earnings for March 12 – December 31, 2012. Based on expected 2012 average outstanding shares of 819M. Guidance incorporates preliminary cost estimates of the impact of Hurricane Sandy. Earnings guidance for OpCos may not add up to consolidated EPS guidance.

Wrap Up

- **Strong financial performance in 2012; increasing and tightening our full year 2012 earnings guidance to \$2.75 - \$2.95/share**
- **Expect \$3 – 6/MWh upside to materialize in the forward curves in 2013**
- **Right platform to take advantage of a power market recovery**
- **Investment grade ratings and dividend are our top priorities**
- **Timing our investments to align with a power market recovery**

Commitment to protect and create shareholder value

APPENDIX

Exelon Generation Disclosures

September 30, 2012

Portfolio Management Strategy

Strategic Policy Alignment

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

Three-Year Ratable Hedging

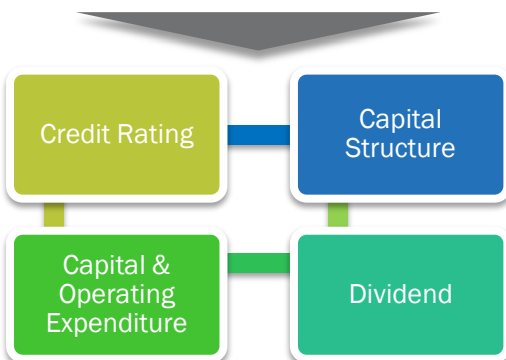
- Ensure stability in near-term cash flows and earnings
- Disciplined approach to hedging
- Tenor aligns with customer preferences and market liquidity
- Multiple channels to market that allow us to maximize margins
- Large open position in outer years to benefit from price upside

Bull / Bear Program

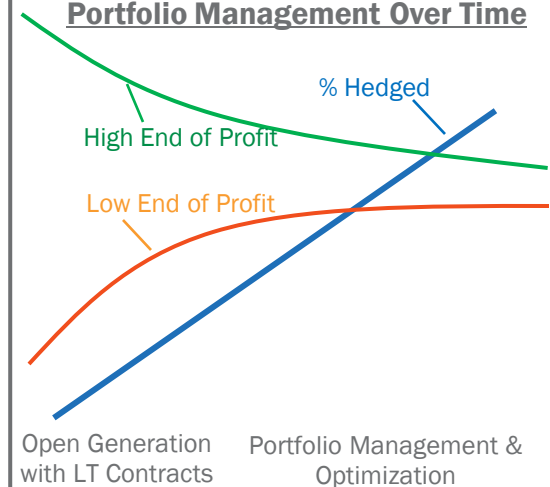
- Ability to exercise fundamental market views to create value within the ratable framework
- Modified timing of hedges versus purely ratable
- Cross-commodity hedging (heat rate positions, options, etc.)
- Delivery locations, regional and zonal spread relationships

Align Hedging & Financials

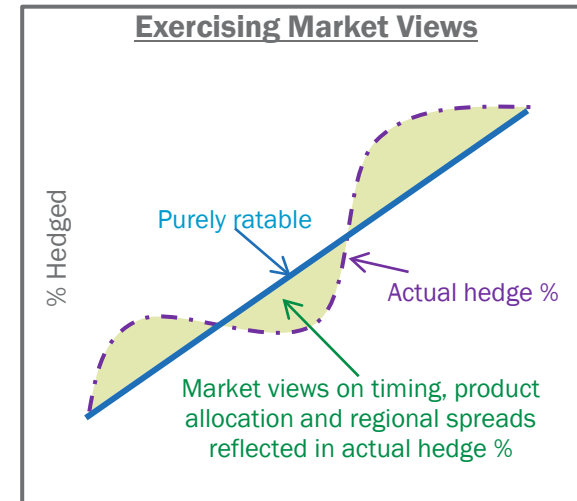
Establishing Minimum Hedge Targets



Portfolio Management Over Time



Exercising Market Views

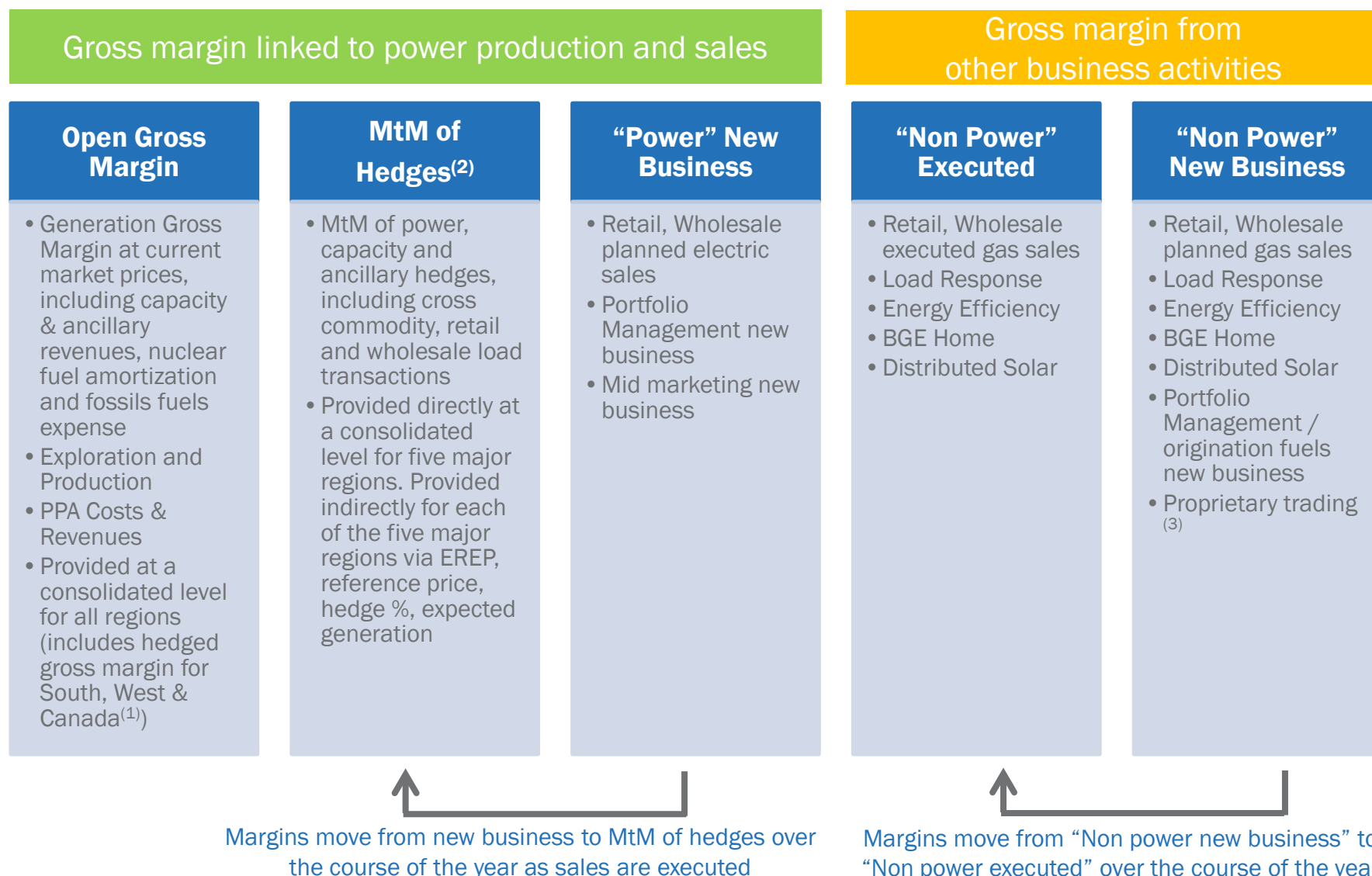


Protect Balance Sheet

Ensure Earnings Stability

Create Value

Components of Gross Margin Categories



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

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

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

ExGen Disclosures

Gross Margin Category (\$M) ^(1,2)	2012 ⁽³⁾	2013	2014	2015
Open Gross Margin (including South, West & Canada hedged GM) ^(4,5)	\$4,500	\$5,750	\$6,050	\$6,200
Mark to Market of Hedges ^(5,6)	\$3,200	\$1,350	\$500	\$250
Power New Business / To Go	\$50	\$500	\$750	\$950
Non-Power Margins Executed	\$300	\$150	\$100	\$50
Non-Power New Business / To Go	\$100	\$450	\$500	\$550
Total Gross Margin	\$8,150	\$8,200	\$7,900	\$8,000

Reference Prices ⁽⁷⁾	2012	2013	2014	2015
Henry Hub Natural Gas (\$/MMbtu)	\$2.77	\$3.84	\$4.18	\$4.37
Midwest: NiHub ATC prices (\$/MWh)	\$28.95	\$30.59	\$31.34	\$32.32
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$33.93	\$38.24	\$39.44	\$40.77
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	\$3.67	\$8.37	\$8.30	\$7.15
New York: NY Zone A (\$/MWh)	\$30.85	\$35.19	\$35.98	\$36.55
New England: Mass Hub ATC Spark Spread(\$/MWh) <i>ALQN Gas, 7.5HR, \$0.50 VOM</i>	\$6.72	\$4.42	\$3.79	\$4.07

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

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

(3) Stub period calculated by excluding Jan 2012 through mid-March 2012 for Constellation only.

(4) Excludes Maryland assets to be divested.

(5) Includes CENG Joint Venture.

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

(7) Based on September 30, 2012 market conditions.

ExGen Disclosures

Generation and Hedges	2012 ⁽¹⁾	2013	2014	2015
<u>Exp. Gen (GWh) ⁽⁴⁾</u>	219,500	218,700	211,400	209,800
Midwest	100,700	97,400	97,500	99,000
Mid-Atlantic ^(2,3)	71,800	75,000	72,200	71,800
ERCOT	19,900	18,500	16,900	15,800
New York ⁽³⁾	13,000	13,800	10,900	9,300
New England	14,100	14,000	13,900	13,900
<u>% of Expected Generation Hedged ⁽⁵⁾</u>	99-102%	88-91%	56-59%	21-24%
Midwest	99-102%	89-92%	56-59%	20-23%
Mid-Atlantic ^(2,3)	99-102%	88-91%	57-60%	24-27%
ERCOT	96-99%	78-81%	53-56%	28-31%
New York ⁽³⁾	98-101%	92-95%	61-64%	15-18%
New England	97-100%	89-92%	51-54%	11-14%
<u>Effective Realized Energy Price (\$/MWh) ⁽⁶⁾</u>				
Midwest	\$42.00	\$38.00	\$35.00	\$34.50
Mid-Atlantic ^(2,3)	\$56.00	\$48.00	\$47.50	\$50.50
ERCOT ⁽⁷⁾	\$9.00	\$7.50	\$5.00	\$5.00
New York ⁽³⁾	\$44.00	\$36.00	\$35.00	\$52.00
New England ⁽⁷⁾	\$8.00	\$7.00	\$4.00	\$5.00

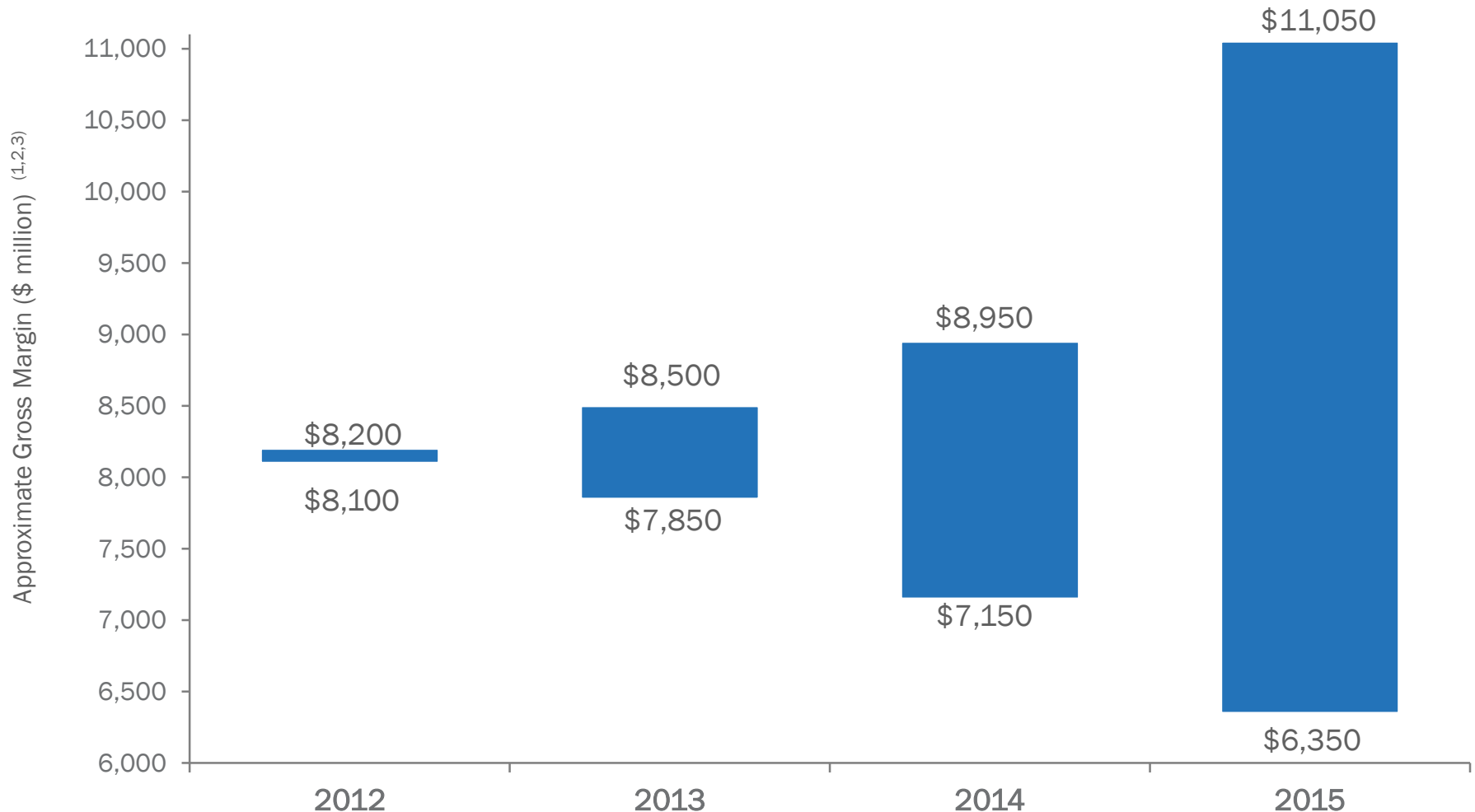
(1) Stub period calculated by excluding Jan 2012 through mid-March 2012 for Constellation only. (2) Excludes Maryland assets to be divested (3) Includes CENG Joint Venture. (4) Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted for capacity. 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 10 refueling outages in 2012 and 2013 and 11 refueling outages in 2014 and 2015 at Exelon-operated nuclear plants and Salem but excludes CENG. Expected generation assumes capacity factors of 92.8%, 93.5%, 93.8%, and 93.3% in 2012, 2013, 2014 and 2015 at Exelon-operated nuclear plants excluding Salem and CENG. These estimates of expected generation in 2012, 2013, 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. (5) 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. (6) 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. (7) Spark spreads shown for ERCOT and New England.

ExGen Hedged Gross Margin Sensitivities

Gross Margin Sensitivities (With Existing Hedges) ^(1, 4)	2012	2013	2014	2015
Henry Hub Natural Gas (\$/MMbtu) ⁽²⁾				
+ \$1/MMbtu	\$(5)	\$55	\$400	\$780
- \$1/MMbtu	\$25	\$(15)	\$(325)	\$(700)
NiHub ATC Energy Price				
+ \$5/MWh	\$(5)	\$40	\$230	\$390
- \$5/MWh	\$5	\$(35)	\$(230)	\$(385)
PJM-W ATC Energy Price ⁽²⁾				
+ \$5/MWh	\$(5)	\$50	\$165	\$295
- \$5/MWh	\$5	\$(40)	\$(160)	\$(285)
NYPP Zone A ATC Energy Price				
+ \$5/MWh	\$5	\$15	\$35	\$45
- \$5/MWh	\$(5)	\$(15)	\$(35)	\$(45)
Nuclear Capacity Factor ⁽³⁾				
+/- 1%	+/- \$10	+/- \$40	+/- \$45	+/- \$45

(1) Based on September 30, 2012 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) Excludes Maryland assets to be divested. (3) Includes CENG Joint Venture (4) Sensitivities based on commodity exposure which includes open generation and all committed transactions.

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 2013 and 2014 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, 2012 (2) Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions. (3) Excludes Maryland assets to be divested.

Illustrative Example of Modeling Exelon Generation 2013 Gross Margin

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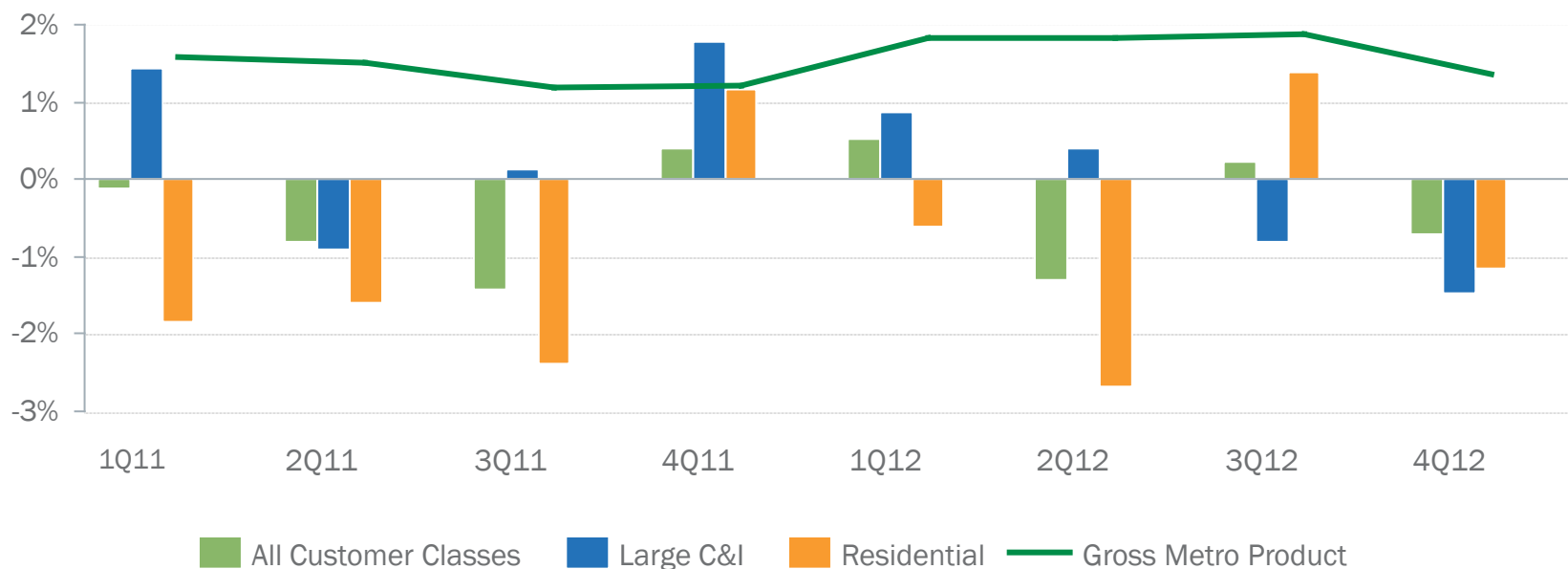
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Row	Item	Midwest	Mid-Atlantic	ERCOT	New England	New York	South, West & Canada
(A)	Start with fleet-wide open gross margin	<div> <div></div> <div>\$5.75 billion</div> <div></div> </div>					
(B)	Expected Generation (TWh)	97.4	75.0	18.5	14.0	13.8	
(C)	Hedge % (assuming mid-point of range)	90.5%	89.5%	79.5%	90.5%	93.5%	
(D=B*C)	Hedged Volume (TWh)	88.2	67.1	14.7	12.7	12.9	
(E)	Effective Realized Energy Price (\$/MWh)	\$38.00	\$48.00	\$7.50	\$7.00	\$36.00	
(F)	Reference Price (\$/MWh)	\$30.59	\$38.24	\$8.37	\$4.42	\$35.19	
(G=E-F)	Difference (\$/MWh)	\$7.41	\$9.76	(\$0.87)	\$2.58	\$0.81	
(H=D*G)	Mark-to-market value of hedges (\$ million) ⁽¹⁾	\$655 million	\$655 million	(\$15) million	\$35 million	\$10 million	
(I=A+H)	Hedged Gross Margin (\$ million)	\$7,100 million					
(J)	Power New Business / To Go (\$ million)	\$500 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	\$8,200 million					

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

ComEd Load Trends

Weather-Normalized Electric Load Year-over-Year



Key Economic Indicators

	Chicago	U.S.
Unemployment rate ⁽¹⁾	8.7%	7.8%
2012 annualized growth in gross domestic/metro product ⁽²⁾	1.7%	2.1%

(1) Source: U.S. Dept. of Labor (September 2012) and Illinois Department of Security (September 2012)

(2) Source: Global Insight (August 2012)

(3) Not adjusted for leap year

Weather-Normalized Electric Load

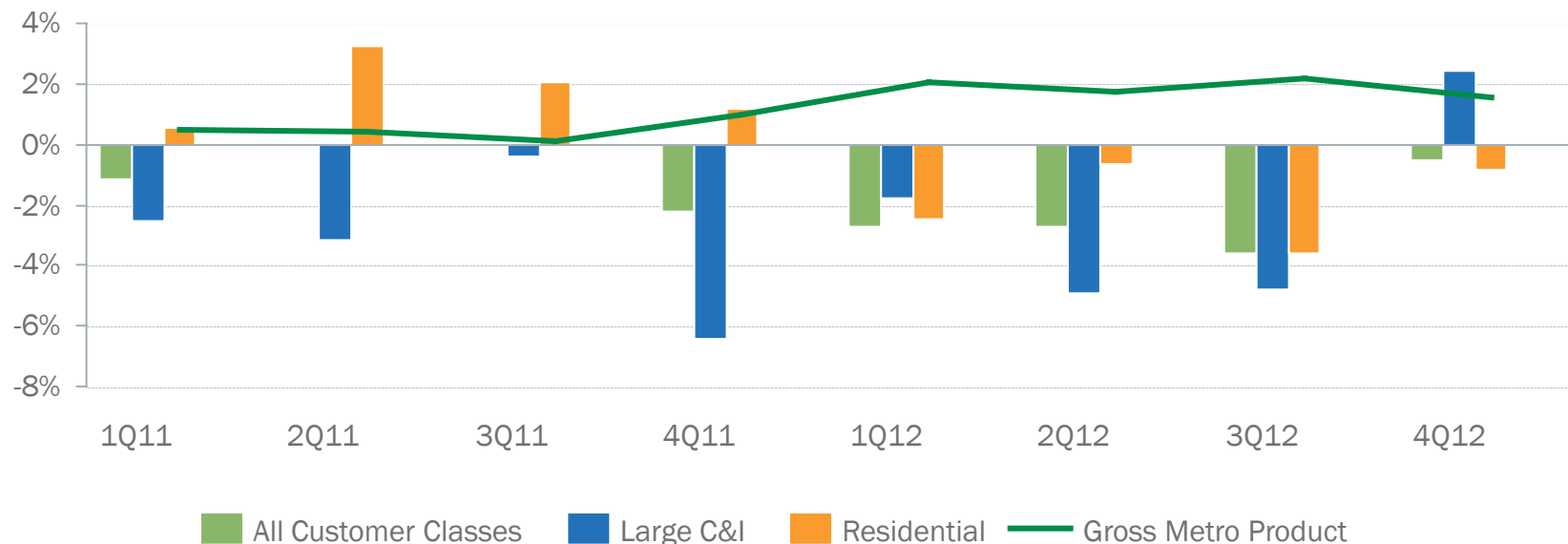
	2011	3Q12	2012E ⁽³⁾
Average Customer Growth	0.4%	0.3%	0.3%
Average Use-Per-Customer	<u>(1.7)%</u>	<u>1.1%</u>	<u>(0.9)%</u>
Total Residential	(1.3)%	1.4%	(0.6)%
Small C&I	(0.8)%	(0.1)%	(0.2)%
Large C&I	0.6%	(0.8)%	(0.3)%
All Customer Classes	(0.5)%	0.2%	(0.3)%

Notes: C&I = Commercial & Industrial. Global Insight re-stated 2011 GMP amounts in August 2012 so there will be a change since 2Q12 earnings release.

ComEd load activity impacts net income to the extent that it does not result in an ROE outside of the collar, which ensures that the earned ROE is within 0.5% of the allowed ROE.

PECO Load Trends

Weather-Normalized Electric Load Year-over-Year



Key Economic Indicators

	Philadelphia	U.S.
Unemployment rate ⁽¹⁾	8.8%	7.8%
2012 annualized growth in gross domestic/metro product ⁽²⁾	1.9%	2.1%

(1) Source: U.S. Dept. of Labor (Sept 2012) - US

US Dept of Labor prelim. data (August 2012) - Philadelphia

(2) Source: Global Insight (August 2012)

(3) Not adjusted for leap year

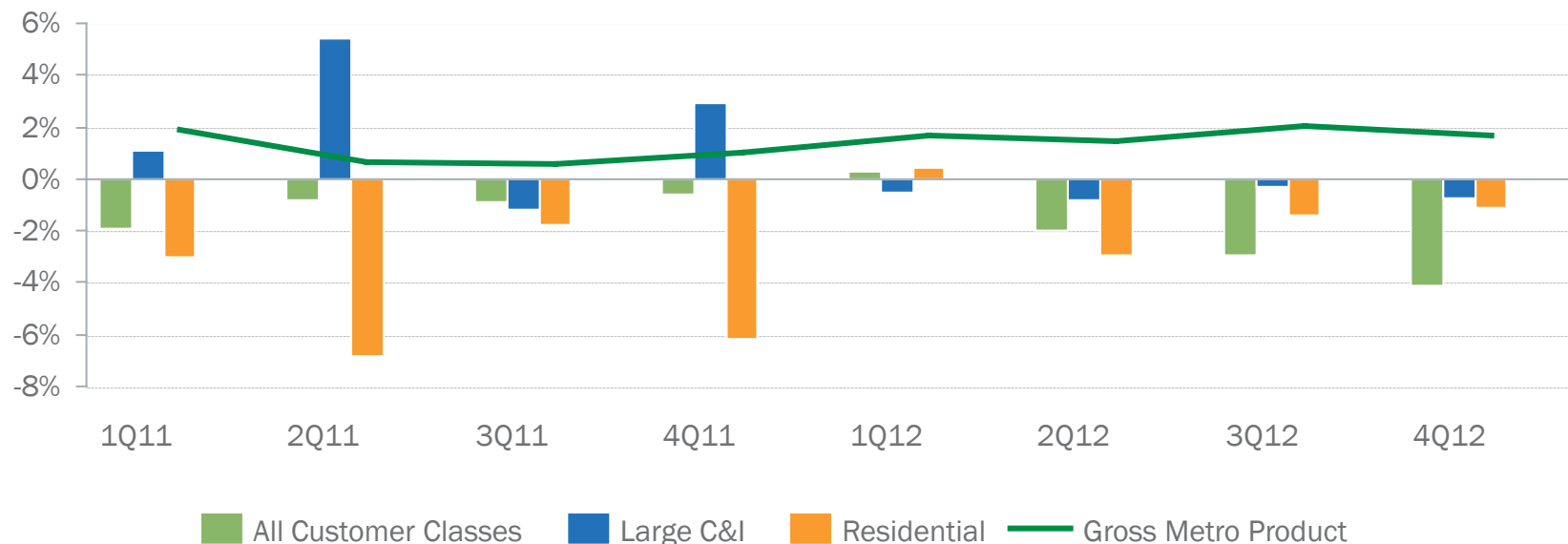
Weather-Normalized Electric Load

	2011	3Q12	2012E ⁽³⁾
Average Customer Growth	0.3%	0.3%	0.4%
Average Use-Per-Customer	<u>1.3%</u>	<u>(3.9)%</u>	<u>(2.4)%</u>
Total Residential	1.7%	(3.6)%	(2.0)%
Small C&I	(0.7)%	(1.7)%	(3.5)%
Large C&I	(3.3)%	(4.8)%	(2.4)%
All Customer Classes	(0.9)%	(3.6)%	(2.4)%

Note: C&I = Commercial & Industrial. Global Insight re-stated 2011 GMP amounts in August 2012 so there will be a change since 2Q12 earnings release.

BGE Load Trends

Weather-Normalized Electric Load Year-over-Year



Key Economic Indicators

	Baltimore	U.S.
Unemployment rate ⁽¹⁾	7.7%	7.8%
2012 annualized growth in gross domestic/metro product ⁽²⁾	1.7%	2.1%

- (1) Source: U.S. Dept. of Labor (Sept 2012) - US
US Dept of Labor prelim. data (August 2012) - Baltimore
(2) Source: Global Insight (August 2012)
(3) Not adjusted for leap year

Weather-Normalized Electric Load

	2011	3Q12	2012E ⁽³⁾
Average Customer Growth	0.2%	0.0%	0.1%
Average Use-Per-Customer	(4.4)%	(1.4)%	(1.3)%
Total Residential	(4.3)%	(1.4)%	(1.2)%
Small C&I	0.8%	0.5%	(3.1)%
Large C&I	2.0%	(0.3)%	(0.6)%
All Customer Classes	(1.1)%	(3.0)%	(2.2)%

Note: C&I = Commercial & Industrial. Global Insight re-stated 2011 GMP amounts in August 2012 so there will be a change since June 2012 Analyst Day presentation.

BGE Rate Case (Updated to reflect 10/22/12 filing)

Rate Case Request ⁽¹⁾	Electric	Gas
Docket #	9299	
Test Year	October 2011 – September 2012	
Common Equity Ratio	48.4%	
Requested Returns	ROE: 10.5%; ROR: 7.96%	
Rate Base	\$2.7B	\$1B
Revenue Requirement Increase	\$131M	\$45M
Proposed Distribution Price Increase as % of overall bill	4%	6%

Timeline

- 10/22/12: Update 8 months actual/4 month estimated test period data with actuals for last 4 months (June-Sept. 2012)
- 11/9/12: BGE and staff/intervenors file rebuttal testimony
- 11/20/12: Staff/Intervenors and BGE file surrebuttal testimony
- 12/3/12 – 12/18/12: Hearings
- 1/11/13: Initial Briefs
- 1/23/13: Reply Briefs
- 2/23/13: Decision
- New rates are in effect shortly after the decision

(1) Initial filing on 7/27/12 used 8 months of actuals and 4 months of projections for October 2011 – September 2012 time period and requested an ROR of 8.02%, electric revenue increase of \$151M and gas revenue increase of \$53M. Rate base, equity ratio and ROE have not changed materially since the 7/27/12 filing.

Minimum Offer Price Rules (MOPR) Update

PJM is proposing modifications to the MOPR to ensure uneconomic generation does not distort market

- Restructured MOPR
 - MOPR to apply to all new gas-fired and IGCC units in PJM, with limited exceptions
 - MOPR exemption to be available only to self-supply entities and competitive market entrants
 - MOPR floor to apply for three years, set at 100% of the net cost of new entry
- Implementation/Timing
 - PJM currently reviewing restructured MOPR with all stakeholders
 - PJM expected to file for FERC approval by November 30, 2012
 - Exelon, other generators, and other stakeholders to support PJM's filing
 - FERC approval expected in early February, 2013








Note: IGCC = Integrated Gasification Combined Cycle. FERC = Federal Energy Regulatory Commission. RPM= Reliability Pricing Model.

Sufficient Liquidity

Available Capacity Under Bank Facilities as of October 24, 2012

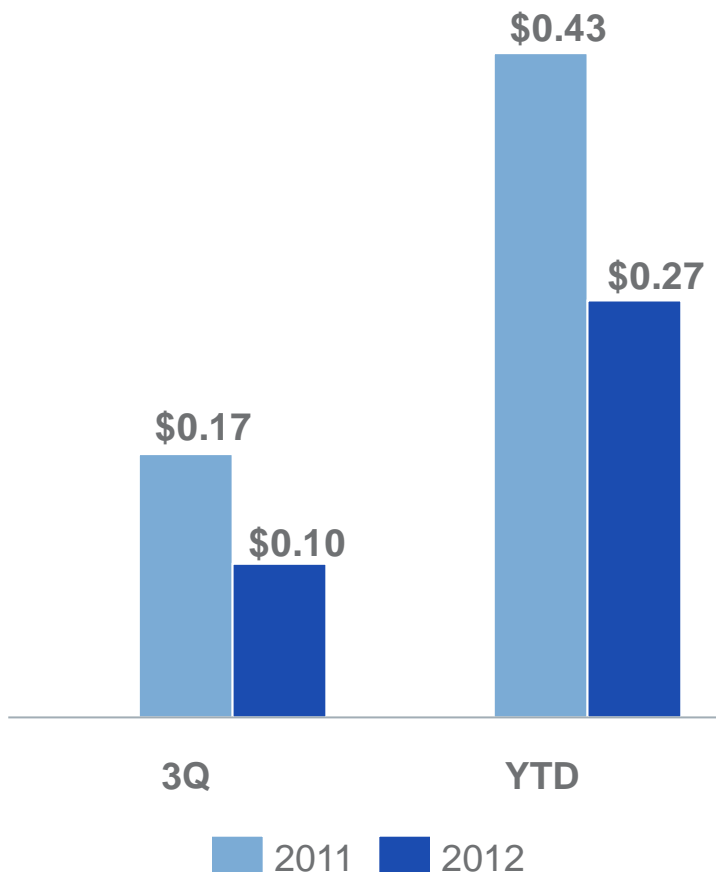
(\$ in Millions)

					 Exelon ⁽³⁾
Aggregate Bank Commitments ⁽¹⁾	600	1,000	600	5,600	9,800
Outstanding Facility Draws	--	--	--	--	--
Outstanding Letters of Credit	(1)	(121)	(1)	(1,950)	(2,089)
Available Capacity Under Facilities⁽²⁾	599	879	599	3,650	7,711
Outstanding Commercial Paper	--	--	--	--	--
Available Capacity Less Outstanding Commercial Paper	599	879	599	3,650	7,711

Exelon Corp, ExGen, PECO and BGE facilities were amended and extended on August 10, 2012 to align maturities of facilities and secure liquidity and pricing through 2017

- (1) Excludes commitments from Exelon's Community and Minority Bank Credit Facility
- (2) Available Capacity Under Facilities represents the unused commitments under the borrower's credit agreements net of outstanding letters of credit and facility draws. The amount of commercial paper outstanding does not reduce the available capacity under the credit agreements.
- (3) Includes Exelon Corporate's \$500M credit facility and legacy Constellation credit facilities assumed as part of the merger, letters of credit and commercial paper outstanding. Exelon will have unwound the \$4.2B in credit facilities assumed from legacy Constellation by the end of the year.

ComEd Operating EPS Contribution



Key Drivers – 3Q12 vs. 3Q11⁽¹⁾

- Share differential: \$(0.04)
- Decreased storm costs⁽²⁾: \$0.04
- Lower distribution revenue primarily due to lower allowed ROE⁽³⁾: \$(0.06)

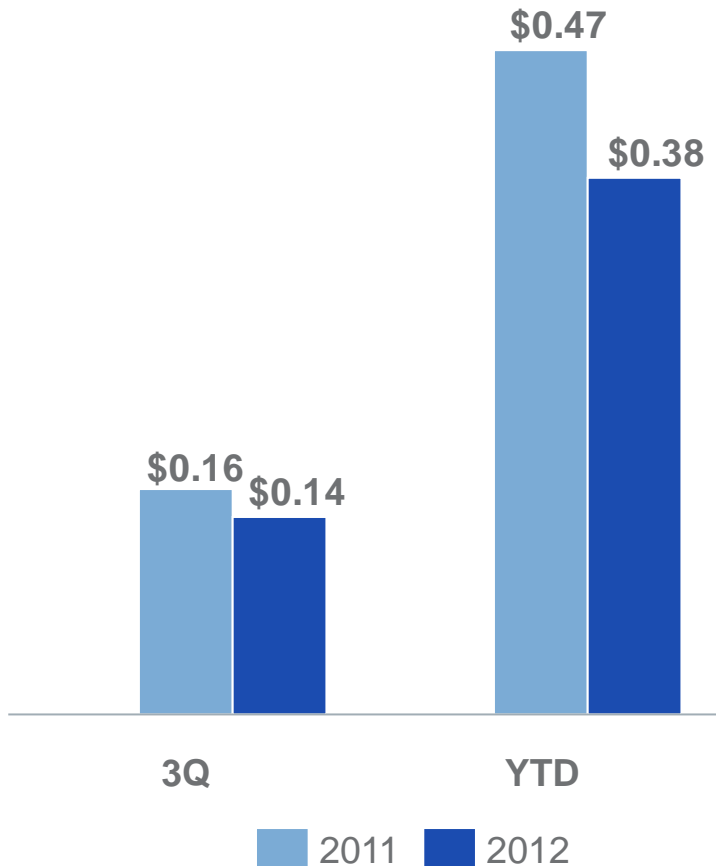
	3Q11 Actual	3Q12 Actual	Normal
Heating Degree-Days	147	107	119
Cooling Degree-Days	785	859	613

(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) Net of costs recoverable through EIMA. During the fourth quarter of 2011, ComEd received a credit of \$0.04 earnings per share, net of amortization, for the allowed recovery of certain 2011 storm costs pursuant to EIMA. During the fourth quarter of 2012, ComEd anticipates recording \$0.10 earnings per share to recognize the impact of the ICC's rehearing decision issued on October 3, 2012.

(3) Due to the true-up mechanism in the distribution formula rate, the primary driver of year-over-year change in earnings will be due to changes in allowed ROE, rate base and capital structure.

PECO Operating EPS Contribution



Key Drivers – 3Q12 vs. 3Q11⁽¹⁾

- Lower income tax in 2011 due to electric T&D tax repairs deduction: \$(0.03)
- Share differential: \$(0.03)
- Lower load growth: \$(0.01)
- Decreased storm costs: \$0.02
- Lower income tax in 2012 due to gas distribution tax repairs deduction: \$0.03

	3Q11 Actual	3Q12 Actual	Normal
Heating Degree-Days	18	14	35
Cooling Degree-Days	1,109	1,138	934

(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.

Note: T&D = Transmission and Distribution

3Q GAAP EPS Reconciliation

<u>Three Months Ended September 30, 2011</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>Other</u>	<u>Exelon</u>
2011 Adjusted (non-GAAP) Operating Earnings Per Share	\$0.79	\$0.17	\$0.16	\$0.01	\$1.12
Mark-to-market impact of economic hedging activities	(0.08)	-	-	-	(0.08)
Unrealized losses related to nuclear decommissioning trust funds	(0.12)	-	-	-	(0.12)
Plant retirements and divestitures	(0.00)	-	-	-	(0.00)
Asset retirement obligation	(0.03)	-	0.00	-	(0.02)
Constellation merger and integration costs	(0.00)	(0.00)	(0.00)	(0.01)	(0.02)
Other acquisition costs	(0.01)	-	-	-	(0.01)
Wolf Hollow acquisition	0.03	-	-	-	0.03
3Q 2011 GAAP Earnings (Loss) Per Share	\$0.58	\$0.17	\$0.16	\$(0.00)	\$0.90

<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	\$0.53	\$0.10	\$0.14	\$(0.00)	\$(0.01)	\$0.77
Mark-to-market impact of economic hedging activities	0.01	-	-	-	0.01	0.02
Unrealized gains related to nuclear decommissioning trust funds	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)	-	(0.00)	(0.00)	(0.00)	(0.04)
Amortization of commodity contract intangibles	(0.21)	-	-	-	-	(0.21)
Amortization of the fair value of certain debt	0.00	-	-	-	-	0.00
3Q 2012 GAAP Earnings (Loss) Per Share	\$0.11	\$0.11	\$0.14	\$(0.00)	\$(0.00)	\$0.35

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

YTD GAAP EPS Reconciliation

<u>Nine Months Ended September 30, 2011</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>Other</u>	<u>Exelon</u>
2011 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$2.47	\$0.43	\$0.47	\$(0.03)	\$3.34
Mark-to-market impact of economic hedging activities	(0.34)	-	-	-	(0.34)
Unrealized losses related to nuclear decommissioning trust funds	(0.07)	-	-	-	(0.07)
Plant retirements and divestitures	(0.04)	-	-	-	(0.04)
Asset retirement obligation	(0.03)	-	0.00	-	(0.02)
Constellation merger and integration costs	(0.00)	(0.00)	(0.00)	(0.03)	(0.04)
Other acquisitions costs	(0.01)	-	-	-	(0.01)
Wolf Hollow acquisition	0.03	-	-	-	0.03
Recovery of costs pursuant to the 2011 distribution rate case order	-	0.03	-	-	0.03
Non-cash charge resulting from Illinois tax rate change legislation	(0.03)	(0.01)	-	(0.00)	(0.04)
YTD 2011 GAAP Earnings (Loss) Per Share	\$1.99	\$0.44	\$0.47	\$(0.07)	\$2.84

<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	\$0.04	\$(0.05)	\$2.21
Mark-to-market impact of economic hedging activities	0.21	-	-	-	0.02	0.23
Unrealized gains related to nuclear decommissioning trust funds	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)	(0.00)	(0.08)	(0.26)
Maryland commitments	(0.03)	-	-	(0.10)	(0.15)	(0.28)
Amortization of commodity contract intangibles	(0.68)	-	-	-	-	(0.68)
FERC settlement	(0.22)	-	-	-	-	(0.22)
Reassessment of state deferred income taxes	0.02	-	-	-	0.13	0.15
Amortization of the fair value of certain debt	0.01	-	-	-	-	0.01
Other acquisition costs	(0.00)	-	-	-	-	(0.00)
YTD 2012 GAAP Earnings (Loss) Per Share	\$0.53	\$0.27	\$0.37	\$(0.07)	\$(0.13)	\$0.97

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 2012 adjusted (non-GAAP) operating earnings outlook excludes the earnings effects of the following:**
 - Mark-to-market adjustments from economic hedging activities
 - Unrealized gains and losses from nuclear decommissioning trust 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 planned retirement of fossil generating units and the expected sale in the fourth quarter of 2012 of three generating stations as required by the merger
 - Changes in decommissioning obligation estimates
 - Certain costs incurred related to the Constellation merger and integration initiatives
 - Costs incurred as part of Maryland commitments in connection with the merger
 - Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at the merger date
 - Costs incurred as part of a March 2012 settlement with the Federal Energy Regulatory Commission (FERC) related to Constellation's prior period hedging and risk management transactions
 - Changes in state deferred tax rates resulting from a reassessment of anticipated apportionment of Exelon's deferred taxes as a result of the merger
 - Non-cash amortization of certain debt recorded at fair value at the merger date expected to be retired in 2013
 - Certain costs incurred associated with other acquisitions
 - Significant impairments of assets, including goodwill
 - Other unusual items
 - Significant changes to GAAP
- **Operating earnings guidance assumes normal weather for remainder of the year**