

# Earnings Conference Call 2<sup>nd</sup> Quarter 2012

August 1<sup>st</sup>, 2012



# Cautionary Statements Regarding Forward-Looking Information

ZECJ-FIN-21 PUBLIC

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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 First Quarter 2012 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors and (b) Part I, Financial Information, ITEM 1. Financial Statements: Note 15; 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.

# Second Quarter Performance and Full Year Guidance

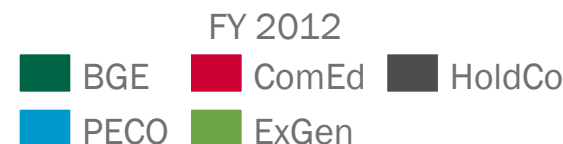
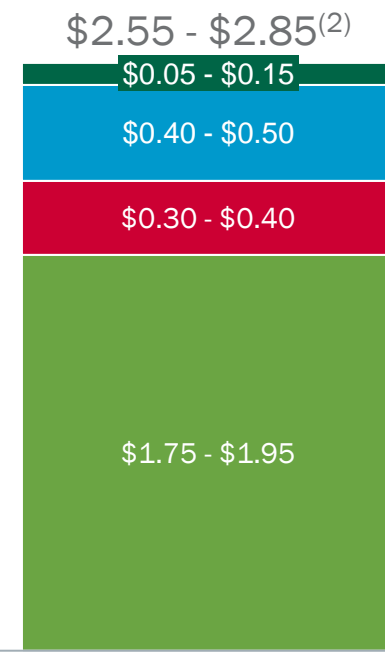
- **Another quarter of solid financial and operating performance**

- Operating earnings in 2Q of \$0.61/share
- Nuclear capacity factor in 2Q of 93.4%
- Load serving business on course to meet volume and margin targets

- **Expect FY 2012 earnings of \$2.55 - \$2.85/share**

- On track to achieve \$170 million in merger related synergies for 2012<sup>(1)</sup>
- On track to meet FY 2012 new business gross margin targets for “Power” and “Non Power” categories

## 2012 Earnings Guidance



**Maintaining FY 2012 operating earnings within \$2.55 - \$2.85/share**

(1) 2012 synergy estimate is applicable for March 12 - December 31, 2012.

(2) 2012 guidance includes Constellation Energy and BGE earnings for March 12 - December 31, 2012. Based on expected 2012 average outstanding shares of 819M. Earnings guidance for OpCos may not add up to consolidated EPS guidance.

# Utility Regulatory Update

## ComEd – ICC Rehearing of 2011 Rate Case

- ICC decision to rehear key elements of ComEd’s rate case is a step in the right direction
- ComEd’s positions are solidly supported by existing legislation
- Expect ICC Order by September 19<sup>th</sup>, 2012 with hearings on August 3<sup>rd</sup>, 2012
- Reversal of original ICC decision on the rehearing items could improve ComEd earnings by ~\$0.10/share in 2012

## BGE – 2012 Rate Case Filing

- On July 27<sup>th</sup>, BGE filed an electric and gas rate case
- Expect order from Maryland PSC by February 2013 with hearings in late 4Q 2012
- Reflects a \$204M increase in revenue requirements for both electric and gas
- New rates expected to be in effect in February / March 2013

BGE 2012 Rate Case Request	Electric	Gas	Total
Rate Base (reflects 13 month average)	\$2.7 B	\$1.0 B	\$3.7 B
Rate of Return (10.5% ROE, 48.4% equity)	8.02%	8.02%	8.02%
Revenue Increase	\$151 M	\$53 M	\$204M

# Key Financial Messages

- Delivered non-GAAP operating earnings in 2Q of \$0.61/share in line with internal expectations
- Continue to create value via our hedging program with strategic decisions on timing, channels and location of sales
- Employing financing strategies to meet funding needs at attractive interest rates
- Expect 3Q 2012 operating earnings in the range of \$0.65 - \$0.75/share

## 2012 2Q Results



FY 2012



**On track to deliver FY 2012 operating earnings within guidance range owing to excellent operational performance**

# ExGen Gross Margin Update

	June 30, 2012			April 30, 2012		
Gross Margin Category (\$ MM) <sup>(1)</sup>	2012 <sup>(2)</sup>	2013	2014	2012 <sup>(2)</sup>	2013	2014
Open Gross Margin <sup>(2,3)</sup> (including South, West, Canada hedged gross margin)	\$4,450	\$5,400	\$5,850	\$4,300	\$5,800	\$6,250
Mark-to-Market of Hedges <sup>(5)</sup>	\$3,100	\$1,650	\$600	\$3,150	\$1,400	\$500
Power New Business / To Go	\$100	\$550	\$850	\$200	\$550	\$850
Non-Power Margins Executed	\$250	\$100	\$100	\$200	\$100	\$50
Non-Power New Business / To Go	\$150	\$500	\$500	\$200	\$500	\$550
<b>Total Gross Margin</b>	<b>\$8,050</b>	<b>\$8,200</b>	<b>\$7,900</b>	<b>\$8,050</b>	<b>\$8,350</b>	<b>\$8,200</b>

## Key Highlights in 2Q 2012

- Continue to ratably hedge entire portfolio, with strategic timing decisions in specific regions:
  - Midwest and Mid-Atlantic wholesale hedging was pared down in a low price environment given higher level of hedging in previous quarters at more favorable prices
  - ERCOT wholesale hedges were significantly increased to capture attractive cash and term spark spreads in early 2Q
  - New England wholesale hedges were increased as spark spreads widened
- For 2012, achieved \$150 million of our “Power” and “Non-Power” New Business / To-Go, which moved into executed buckets
- For 2013 and 2014, we expect the power ‘New Business / To-Go’ margins to start moving into the executed category as we enter a more seasonally active sales cycle in the retail and wholesale business

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

(2) Stub period calculated by excluding Jan 2012 thru 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.

# 2012 Projected Sources and Uses of Cash

(\$ in Millions)



<b>Beginning Cash Balance<sup>(1)</sup></b>					<b>\$550</b>
Cash acquired from Constellation <sup>(2)</sup>	150	n/a	n/a	1,375	1,650
Cash Flow from Operations <sup>(3)</sup>	250	975	800	3,450	5,375
CapEx (excluding other items below):	(475)	(1,200)	(350)	(1,000)	(3,075)
Nuclear Fuel	n/a	n/a	n/a	(1,175)	(1,175)
Dividend <sup>(4)</sup>					(1,725)
Nuclear Upgrades	n/a	n/a	n/a	(350)	(350)
Wind	n/a	n/a	n/a	(650)	(650)
Solar	n/a	n/a	n/a	(675)	(675)
Upstream	n/a	n/a	n/a	(75)	(75)
Utility Smart Grid/Smart Meter	(75)	(75)	(75)	n/a	(225)
Net Financing (excluding Dividend):					
Planned Debt Issuances <sup>(5)</sup>	250	375	350	775	1,750
Planned Debt Retirements	(175)	(450)	(375)	(75)	(1,075)
Project Finance/Federal Financing Bank Loan	n/a	n/a	n/a	375	375
Other <sup>(6)</sup>	25	250	25	(50)	75
<b>Ending Cash Balance<sup>(1)</sup></b>					<b>\$750</b>

(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 31, 2012.

(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.

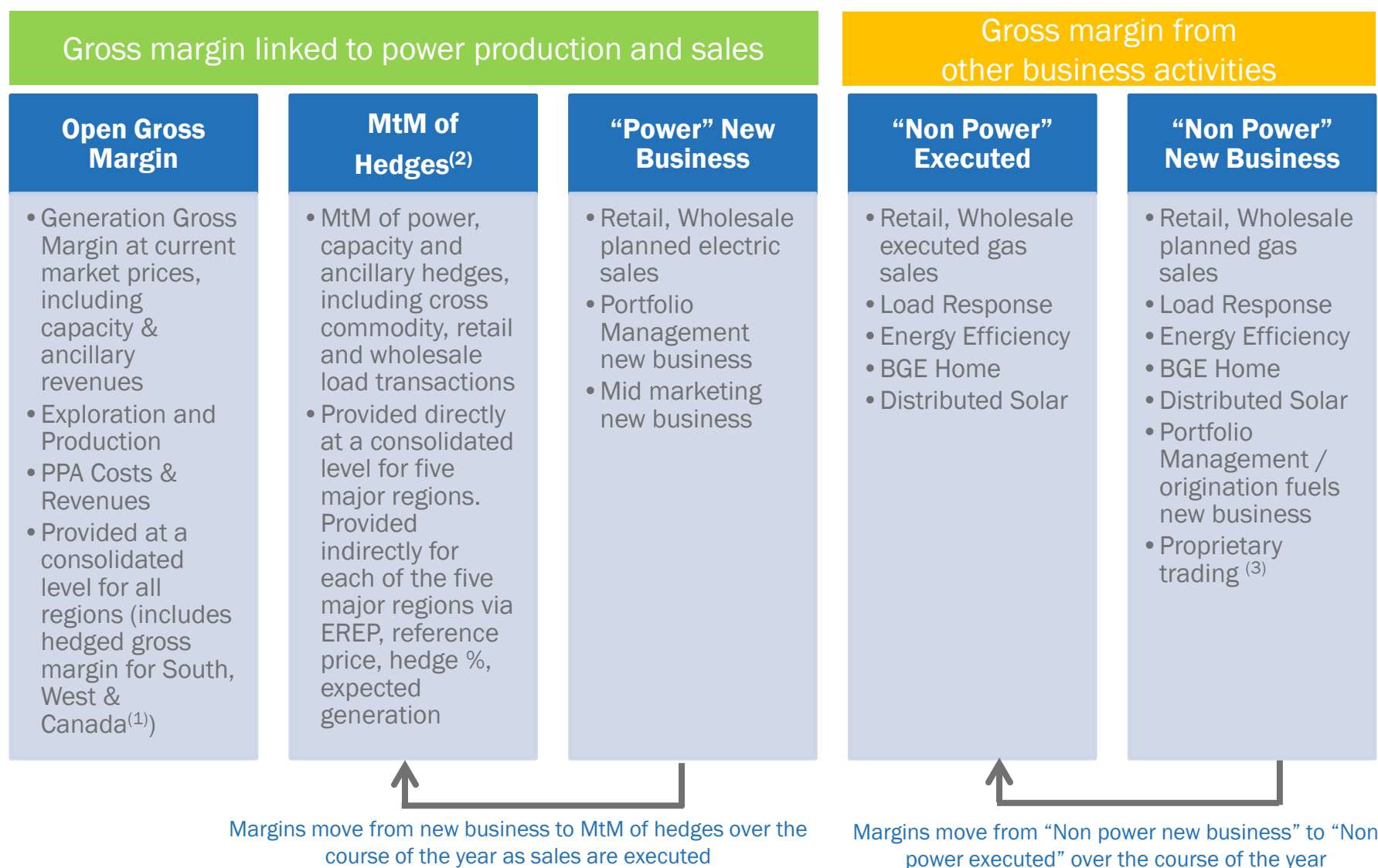
# APPENDIX



# **ExGen Disclosures**

**June 30, 2012**

# 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 (\$ MM) <sup>(1)</sup>	2012 <sup>(2)</sup>	2013	2014
Open Gross Margin (including South, West & Canada hedged GM) <sup>(3,4)</sup>	\$4,450	\$5,400	\$5,850
Mark to Market of Hedges <sup>(5)</sup>	\$3,100	\$1,650	\$600
Power New Business / To Go	\$100	\$550	\$850
Non-Power Margins Executed	\$250	\$100	\$100
Non-Power New Business / To Go	\$150	\$500	\$500
<b>Total Gross Margin</b>	<b>\$8,050</b>	<b>\$8,200</b>	<b>\$7,900</b>

Reference Prices <sup>(6)</sup>	2012	2013	2014
Henry Hub Natural Gas (\$/MMbtu)	\$2.72	\$3.58	\$3.95
Midwest: NiHub ATC prices (\$/MWh)	\$27.17	\$28.85	\$30.57
Mid-Atlantic: PJM-W ATC prices (\$/MWh)	\$32.35	\$36.25	\$38.42
ERCOT-N ATC Spark Spread (\$/MWh) <i>HSC Gas, 7.2HR, \$2.50 VOM</i>	\$12.19	\$7.44	\$6.48
New York: NY Zone A (\$/MWh)	\$29.55	\$31.45	\$32.99
New England: Mass Hub ATC Spark Spread(\$/MWh) <i>ALQN Gas, 7.5HR, \$0.50 VOM</i>	\$6.17	\$4.93	\$4.20

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

(2) Stub period calculated by excluding Jan 2012 thru 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.

(6) Based on June 29, 2012 market conditions.

# ExGen Disclosures

Generation and Hedges	2012 <sup>(1)</sup>	2013	2014
<u>Exp. Gen (GWh) <sup>(4)</sup></u>	<b>219,600</b>	<b>216,900</b>	<b>209,200</b>
Midwest	101,000	97,600	97,600
Mid-Atlantic <sup>(2,3)</sup>	71,900	73,600	71,400
ERCOT	19,900	17,800	15,400
New York <sup>(3)</sup>	13,400	13,600	10,700
New England	13,400	14,300	14,100
<u>% of Expected Generation Hedged <sup>(5)</sup></u>	<b>99-102%</b>	<b>79-82%</b>	<b>46-49%</b>
Midwest	98-101%	80-83%	47-50%
Mid-Atlantic <sup>(2,3)</sup>	102-105%	78-81%	49-52%
ERCOT	96-99%	70-73%	39-42%
New York <sup>(3)</sup>	101-104%	85-88%	38-41%
New England	96-99%	79-82%	41-44%
<u>Effective Realized Energy Price (\$/MWh) <sup>(6)</sup></u>			
Midwest	40.50	39.00	36.00
Mid-Atlantic <sup>(2,3)</sup>	53.50	49.00	48.00
ERCOT <sup>7</sup>	9.00	7.00	4.00
New York <sup>(3)</sup>	45.00	37.00	37.50
New England <sup>(7)</sup>	7.50	7.00	4.00

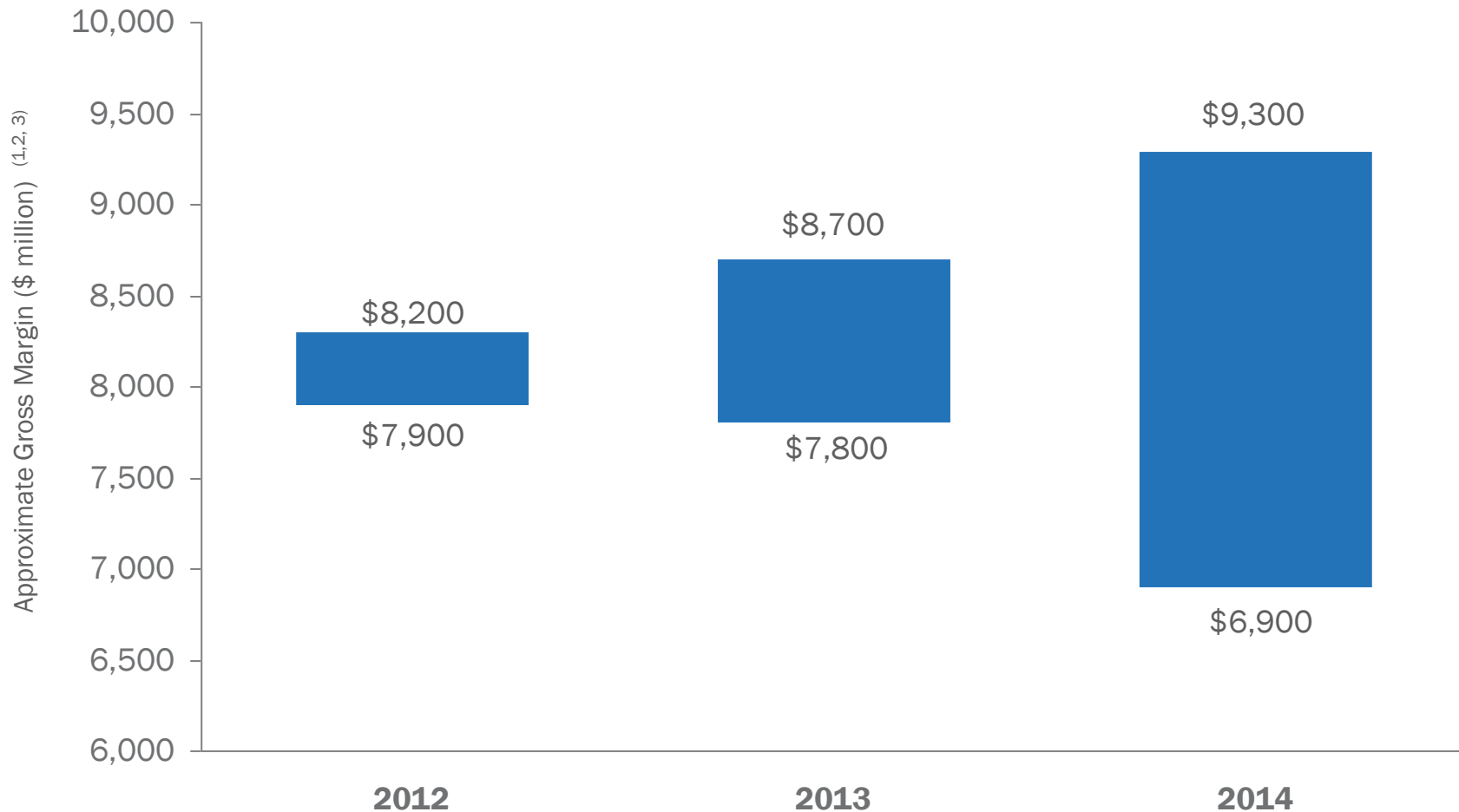
(1) Stub period calculated by excluding Jan 2012 thru mid-March 2012 for Constellation only. (2) Excludes Maryland assets to be divested (3) Includes CENG Joint Venture. (4) Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted for capacity. 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 at Exelon-operated nuclear plants and Salem but excludes CENG. Expected generation assumes capacity factors of 93.1%, 93.3% and 93.8% in 2012, 2013 and 2014 at Exelon-operated nuclear plants excluding Salem and CENG. These estimates of expected generation in 2012, 2013 and 2014 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) <sup>(1,4)</sup>	2012	2013	2014
Henry Hub Natural Gas (\$/MMbtu) <sup>(2)</sup>			
+ \$1/MMbtu	\$(65)	\$120	\$490
- \$1/MMbtu	\$75	\$(100)	\$(430)
NiHub ATC Energy Price			
+ \$5/MWh	\$5	\$85	\$280
- \$5/MWh	\$(5)	\$(85)	\$(275)
PJM-W ATC Energy Price <sup>(2)</sup>			
+ \$5/MWh	\$(15)	\$80	\$190
- \$5/MWh	\$15	\$(80)	\$(185)
NYPP Zone A ATC Energy Price			
+ \$5/MWh	\$5	\$10	\$45
- \$5/MWh	\$(5)	\$(10)	\$(45)
Nuclear Capacity Factor <sup>(3)</sup>			
+/- 1%	+/- \$15	+/- \$40	+/- \$40

(1) Based on June 29, 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 June 29, 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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PUBLIC

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	<div> <div></div> <div>\$5.4 billion</div> <div></div> </div>					
(B)	Expected Generation (TWh)	97.6	73.6	17.8	13.6	14.3	
(C)	Hedge % (assuming mid-point of range)	81.5%	79.5%	71.5%	86.5%	80.5%	
(D=B*C)	Hedged Volume (TWh)	79.5	58.5	12.7	11.9	11.7	
(E)	Effective Realized Energy Price (\$/MWh)	\$39.00	\$49.00	\$7.00	\$37.00	\$7.00	
(F)	Reference Price (\$/MWh)	\$28.85	\$36.25	\$7.44	\$31.45	\$4.93	
(G=E-F)	Difference (\$/MWh)	\$10.15	\$12.75	(\$0.44)	\$5.55	\$2.07	
(H=D*G)	Mark-to-market value of hedges (\$ million) <sup>(1)</sup>	\$810 million	\$745 million	(\$5) million	\$65 million	\$25 million	
(I=A+H)	Hedged Gross Margin (\$ million)	\$7,050 million					
(J)	Power New Business / To Go (\$ million)	\$550 million					
(K)	Non-Power Margins Executed (\$ million)	\$100 million					
(L)	Non-Power New Business / To Go (\$ million)	\$500 million					
(N=I+J+K+L)	Total Gross Margin	\$8,200 million					

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

# Additional 2012 ExGen Modeling

P&L Item	2012 Stub <sup>(1)</sup> Estimate	2012 Full-Year <sup>(2)</sup> Estimate
O&M <sup>(3)</sup>	\$4,000M	\$4,250M
Taxes Other Than Income (TOTI)	\$300M	\$300M
Depreciation & Amortization <sup>(4)</sup>	\$650M	\$700M
Interest Expense	\$300M	\$350M

(1) Stub period represents estimates for March 12 – December 31, 2012 and is reflected as part of ExGen's 2012 earnings guidance

(2) Full-year estimates provided for modeling purposes.

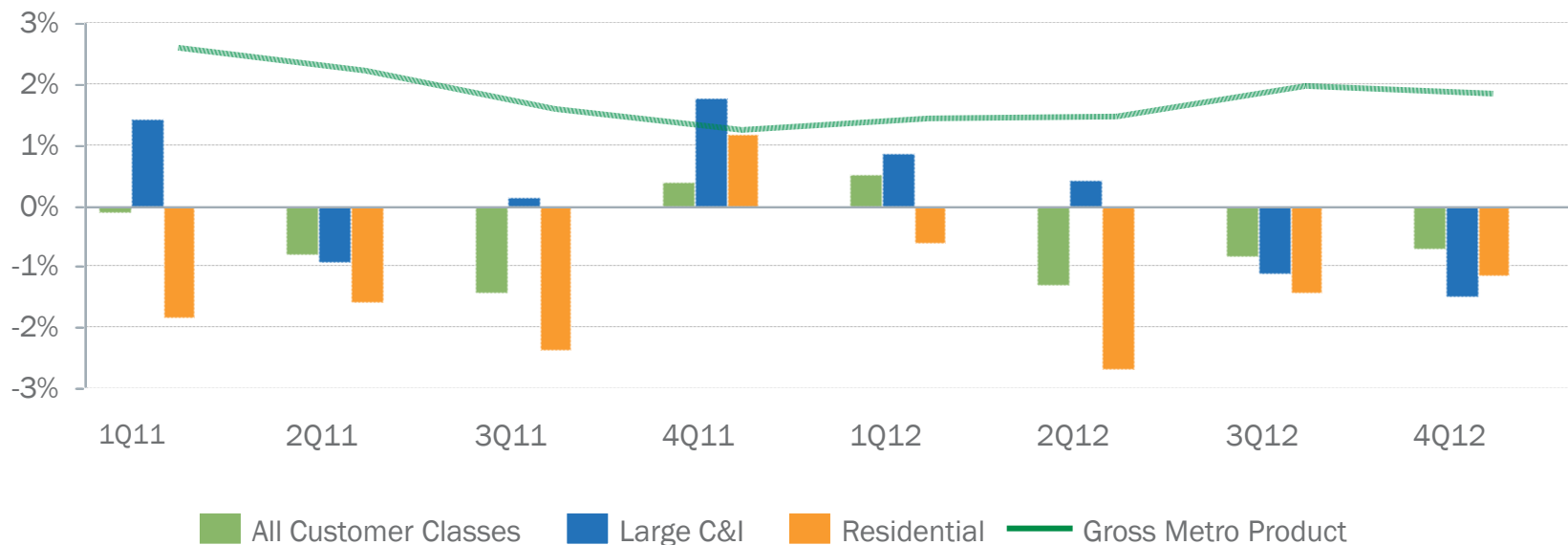
(3) ExGen O&M does not include CENG O&M of ~\$350M in the stub estimate. CENG O&M will be reflected under "Equity earnings of unconsolidated affiliates" in the Income Statement. In addition, we have removed the impact from O&M related to entities consolidated solely as a result of the application of FIN 46R. Our 2012 earnings guidance (prior or current) is not impacted by this change to O&M since the application of FIN 46R does not impact net income.

(4) ExGen D&A does not include CENG D&A of ~\$100M in the stub estimate. CENG D&A will be reflected under "Equity earnings of unconsolidated affiliates" in the Income Statement.



# ComEd Load Trends

## Weather-Normalized Electric Load Year-over-Year



## Key Economic Indicators

	Chicago	U.S.
Unemployment rate <sup>(1)</sup>	8.6%	8.2%
2012 annualized growth in gross domestic/metro product <sup>(2)</sup>	1.7%	2.2%

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

(2) Source: Global Insight (May 2012)

(3) Not adjusted for leap year

## Weather-Normalized Electric Load

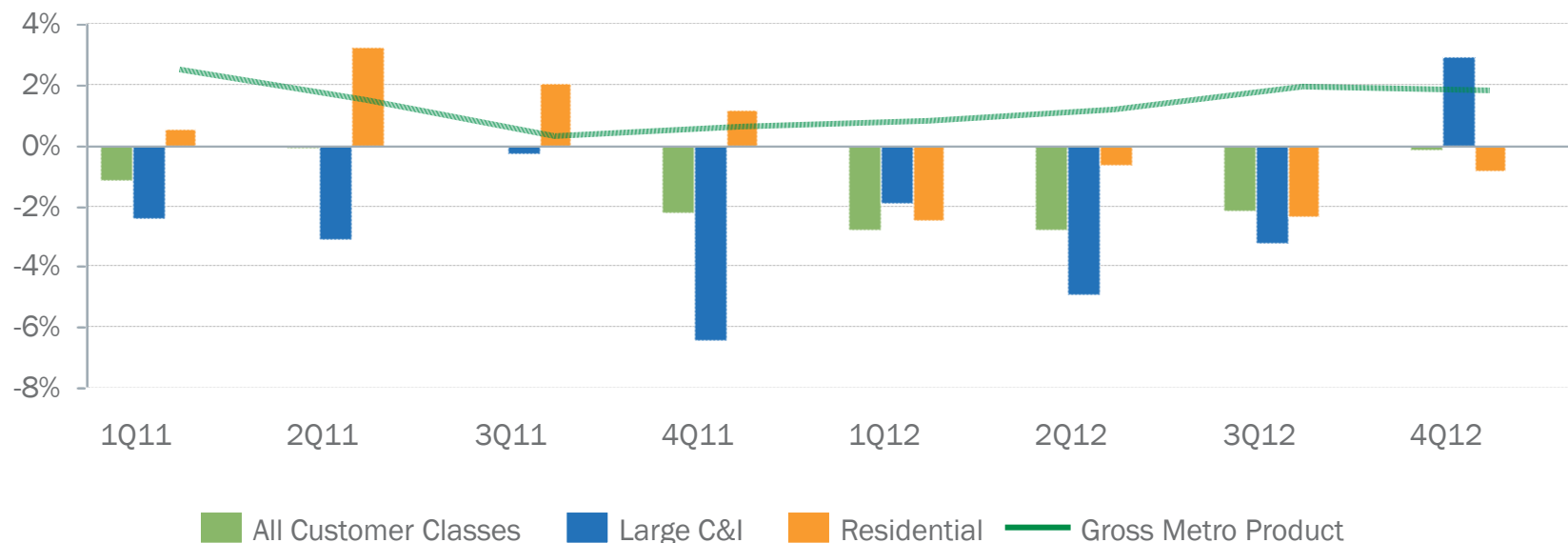
	2011	2012	2012E <sup>(3)</sup>
Average Customer Growth	0.4%	0.3%	0.3%
Average Use-Per-Customer	<u>(1.7)%</u>	<u>(3.0)%</u>	<u>(1.7)%</u>
Total Residential	(1.3)%	(2.7)%	(1.4)%
Small C&I	(0.8)%	(1.8)%	(0.2)%
Large C&I	0.6%	0.4%	(0.4)%
All Customer Classes	(0.5)%	(1.3)%	(0.6)%

Notes: C&I = Commercial & Industrial.

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 <sup>(1)</sup>	7.8%	8.2%
2012 annualized growth in gross domestic/metro product <sup>(2)</sup>	1.4%	2.2%

(1) Source: U.S. Dept. of Labor (June 2012) - US  
US Dept of Labor prelim. data (June 2012) - Philadelphia

(2) Source: Global Insight (May 2012)

(3) Not adjusted for leap year

## Weather-Normalized Electric Load

	2011	2012	2012E <sup>(3)</sup>
Average Customer Growth	0.3%	0.4%	0.5%
Average Use-Per-Customer	<u>1.3%</u>	<u>(1.0)%</u>	<u>(2.1)%</u>
Total Residential	1.7%	(0.7)%	(1.7)%
Small C&I	(0.7)%	(1.9)%	(3.2)%
Large C&I	(3.3)%	(4.9)%	(1.8)%
All Customer Classes	(0.9)%	(2.7)%	(2.0)%

# Sufficient Liquidity

## Available Capacity Under Bank Facilities as of July 27, 2012

(\$ in Millions)



Aggregate Bank Commitments <sup>(1)</sup>	600	1,000	600	5,600	10,640
Outstanding Facility Draws	--	--	--	--	--
Outstanding Letters of Credit	(1)	(1)	(1)	(1,793)	(2,317)
<b>Available Capacity Under Facilities<sup>(2)</sup></b>	<b>599</b>	<b>999</b>	<b>599</b>	<b>3,807</b>	<b>8,323</b>
Outstanding Commercial Paper	(35)	(256)	--	--	(462)
<b>Available Capacity Less Outstanding Commercial Paper</b>	<b>564</b>	<b>743</b>	<b>599</b>	<b>3,807</b>	<b>7,861</b>

Exelon Corp, ExGen, PECO and BGE facilities will be amended and extended to align maturities of Exelon 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 be unwinding the \$4B in credit facilities assumed from legacy Constellation over the remainder of the year.

# ComEd Distribution Rate Case Update

## Summary of Filings

**2011 Formula Rate Filing (Docket # 11-0721 filed 11/8/11; rates eff. June 2012):**

- Based on 2010 calendar year costs and 2011 net plant additions
- Supported \$59M distribution revenue requirement reduction
- 10.05% ROE (2010 Treasury yield of 4.25% + 580 basis point risk premium)

ICC Final Order (issued 5/30/12):

- \$168M revenue requirement reduction; incremental reduction includes:
  - ~\$50M related to costs ICC determined should be recovered through alternative rate recovery tariffs or reflected in reconciliation proceeding; primarily delays timing of cash flows
  - ~\$35M reflects disallowance of return on pension asset
  - ~\$10M reflects incentive compensation related adjustments
  - ~\$15M reflects various adjustments for cash working capital, operating reserves and other technical items
- ComEd requested and the ICC granted expedited rehearing on the pension, interest rate, and average rate base issues; Commission Final Order expected by Sept. 19.

2010												2011												2012											
J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Costs used for filing																																			
												Plant additions used for filing																							
																								Formula rate filing											
																								Rates in effect											

**2012 Formula Rate Filing (Docket # 12-0321 filed 4/30/12, rates eff. Jan 2013)**

- 2012 plan year based on 2011 actual costs and 2012 net plant additions
  - 9.71% ROE (2011 Treasury yield of 3.91% + 580 basis point risk premium)
- Reconciled 2011 revenue requirements in effect to 2011 actual costs incurred
  - 9.81% ROE (3.91% plus 590 basis point risk premium)<sup>(1)</sup>
- Initial filing supported \$106M distribution revenue requirement increase relative to Dec. 2012 rates as ComEd initially proposed. When factoring in 5/30/12 order for #11-0721, ComEd proposed a \$34M reduction
- Received staff and intervener testimony on 7/17/12
  - Staff proposes an additional \$35M reduction beyond ComEd's filing
- ICC order by year end; rates effective January 2013

2011												2012												2013											
J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Costs used for filing																																			
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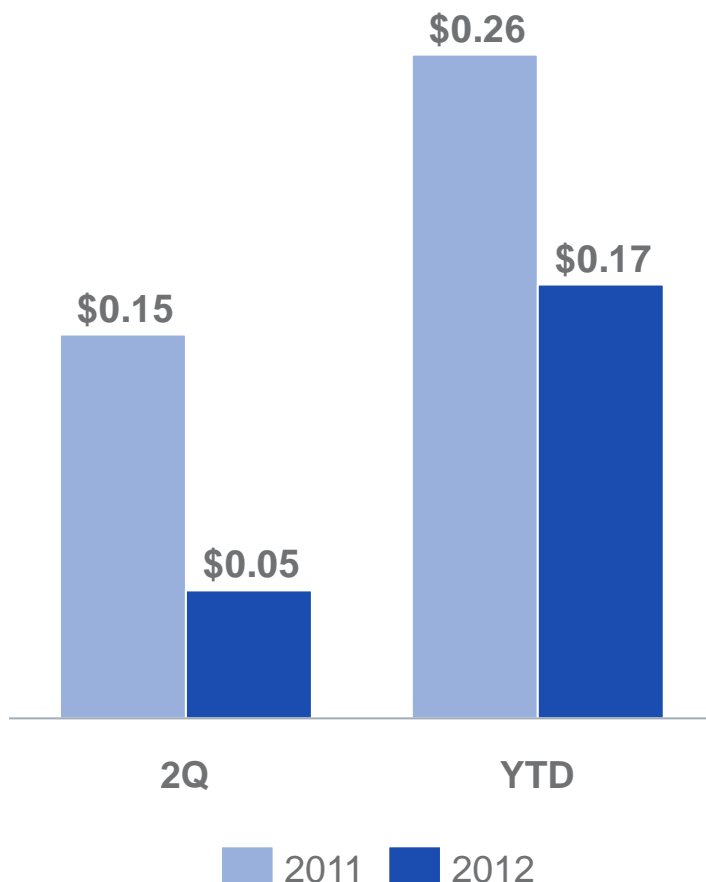
(1) 590 basis point premium applies only to 2011 revenue reconciliation. All subsequent revenue reconciliations will assume a 580 basis point premium.

# BGE Rate Case Overview

Rate Case Request	Electric	Gas
Docket #	9299	
Test Year	October 2011 – September 2012	
Common Equity Ratio	48.4%	
Requested Returns	ROE: 10.5%; ROR: 8.02%	
Rate Base	\$2.7B	\$1B
Revenue Requirement Increase	\$151M	\$53M
Proposed Distribution Price Increase as % of overall bill	4%	7%

Timeline	2012						2013		
	Aug	Sep	Oct	Nov	Dec		Jan	Feb	Mar
Filed	▲ 7/27/12								
Hearings									
Final Order Expected									
New Rates Effective									

# ComEd Operating EPS Contribution



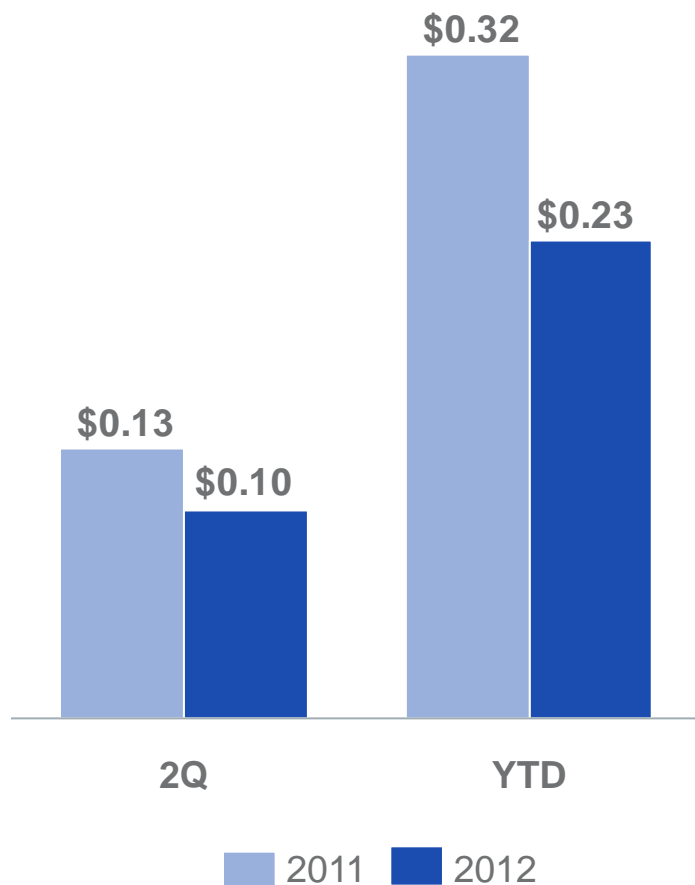
## Key Drivers – 2012 vs. 2011 <sup>(1)</sup>

- Impacts of the 2012 distribution formula rate order under the Energy Infrastructure Modernization Act: \$(0.07)
- Share differential: \$(0.04)
- One-time impacts of the 2011 distribution rate case order: \$(0.03)
- Weather: \$0.01

	2011 <u>Actual</u>	2012 <u>Actual</u>	<u>Normal</u>
Heating Degree-Days	823	544	765
Cooling Degree-Days	237	423	218

(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.

# PECO Operating EPS Contribution



## Key Drivers – 2Q12 vs. 2Q11 <sup>(1)</sup>

➤ Share differential: \$(0.03)

	2Q11 <u>Actual</u>	2Q12 <u>Actual</u>	<u>Normal</u>
Heating Degree-Days	331	337	463
Cooling Degree-Days	494	430	348

(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.

# 2Q GAAP EPS Reconciliation

<u>Three Months Ended June 30, 2011</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>Other</u>	<u>Exelon</u>
<b>2011 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$0.79</b>	<b>\$0.15</b>	<b>\$0.13</b>	<b>\$(0.01)</b>	<b>\$1.05</b>
Mark-to-market impact of economic hedging activities	(0.12)	-	-	-	(0.12)
Unrealized gains related to nuclear decommissioning trust funds	0.01	-	-	-	0.01
Plant retirements and divestitures	(0.02)	-	-	-	(0.02)
Recovery of costs pursuant to the 2011 distribution rate case order	-	0.03	-	-	0.03
Constellation merger and integration costs	-	-	-	(0.02)	(0.02)
<b>2Q 2011 GAAP Earnings (Loss) Per Share</b>	<b>\$0.67</b>	<b>\$0.17</b>	<b>\$0.03</b>	<b>\$(0.03)</b>	<b>\$0.93</b>

<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>
<b>2012 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$0.47</b>	<b>\$0.05</b>	<b>\$0.10</b>	<b>\$0.02</b>	<b>\$(0.02)</b>	<b>\$0.61</b>
Mark-to-market impact of economic hedging activities	0.14	-	-	-	0.00	0.15
Unrealized losses related to nuclear decommissioning trust funds	(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
Reassessment of state deferred income taxes	-	-	-	-	0.00	0.00
<b>2Q 2012 GAAP Earnings (Loss) Per Share</b>	<b>\$0.19</b>	<b>\$0.05</b>	<b>\$0.09</b>	<b>\$0.01</b>	<b>\$(0.02)</b>	<b>\$0.33</b>

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>Six Months Ended June 30, 2011</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>Other</u>	<u>Exelon</u>
<b>2011 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$1.69</b>	<b>\$0.26</b>	<b>\$0.32</b>	<b>\$(0.04)</b>	<b>\$2.22</b>
Mark-to-market impact of economic hedging activities	(0.25)	-	-	-	(0.25)
Unrealized gains related to nuclear decommissioning trust funds	0.04	-	-	-	0.04
Plant retirements and divestitures	(0.04)	-	-	-	(0.04)
Non-cash charge resulting from health care legislation	(0.03)	(0.01)	-	-	(0.04)
Recovery of costs pursuant to the 2011 distribution rate case order	-	0.03	-	-	0.03
Constellation merger and integration costs	-	-	-	(0.02)	(0.02)
<b>YTD 2011 GAAP Earnings (Loss) Per Share</b>	<b>\$1.41</b>	<b>\$0.28</b>	<b>\$0.26</b>	<b>\$(0.07)</b>	<b>\$1.94</b>

<u>Six Months Ended June 30, 2012</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>Other</u>	<u>Exelon</u>
<b>2012 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$1.03</b>	<b>\$0.17</b>	<b>\$0.23</b>	<b>\$0.04</b>	<b>\$(0.03)</b>	<b>\$1.44</b>
Mark-to-market impact of economic hedging activities	0.20	-	-	-	0.01	0.21
Unrealized gains related to nuclear decommissioning trust funds	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)
FERC settlement	(0.22)	-	-	-	-	(0.22)
Reassessment of state deferred income taxes	0.02	-	-	-	0.14	0.16
Amortization of the fair value of certain debt	0.00	-	-	-	-	0.00
Other acquisition costs	(0.00)	-	-	-	-	(0.00)
<b>YTD 2012 GAAP Earnings (Loss) Per Share</b>	<b>\$0.43</b>	<b>\$0.17</b>	<b>\$0.22</b>	<b>\$(0.07)</b>	<b>\$(0.13)</b>	<b>\$0.62</b>

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

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- **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
  - Certain costs 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
  - Revenues and operating expenses related to three generation facilities required to be sold within 180 days of the merger
  - Non-cash benefit associated with a change 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**