

Bank of America Merrill Lynch 2012 Power and Gas Leaders Conference

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Cautionary Statements Regarding Forward-Looking Information

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This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company and Exelon Generation Company, LLC (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 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.

Maintaining Strength Under Current Market Conditions

Current forward power prices do not reflect anticipated recovery

- Our internal market analysis forecasts \$3/MWh upside at PJW-WHUB and \$5/MWh upside at NIHUB
- Power markets do not reflect tightening of the supply stack from coal retirements and MATS compliance costs

Options are available to manage through the downturn

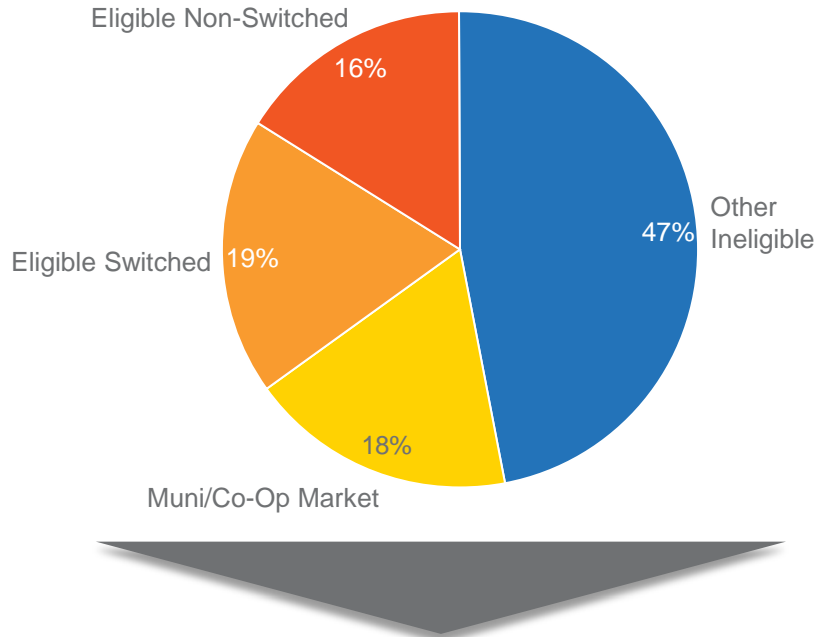
- Currently reviewing plans to identify additional cost savings
- Re-evaluating the timing and amount of uprate and renewable spend

Our business decisions will be reflective of various considerations including current market views, our internal fundamental views and the method to most effectively create and return value to shareholders

Constellation: Electric Retail Business Strategy

Total U.S. Power Market in 2012

Estimated Load ~ 3,700 TWh ⁽¹⁾



Through retail and wholesale channels, Constellation currently serves 170 TWhs, or approximately 5%, of total U.S. power demand

Expected Total Competitive Market Growth

- Underlying load growth
 - More than 1% annual load growth across the U.S.
- Switched market expected to grow by approximately 11% in C&I from 2011 to 2014
 - Existing markets: PA and OH
 - New markets: MI and AZ
- Switched market expected to grow by approximately 15% in residential from 2011 to 2014

Strategy to Grow

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

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

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

Exelon Utilities: Rate Case Progress

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 on September 19th, 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 27th, 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 late February 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

Exelon Utilities will deliver on operational and financial performance and utilize existing rate making frameworks to earn a fair and reasonable return

Modifying the Minimum Offer Price Rules

Goal of Advocacy Efforts:

- Protect competitive markets against attempts to undermine price signals and ensure uneconomic generation does not distort market
- Ensure that generators receiving subsidies bid their appropriate cost into the RPM auction

Concerns with Existing MOPR:

- MOPR exemption process allows non-competitive supply to escape market power mitigation, and fails to properly consider the value of out-of-market contracts
- MOPR does not apply throughout RTO
- MOPR floor applies only for one year and is set at 90% of the net cost of new entry

Path Forward:

- Stakeholders reviewing methods to restructure MOPR
- Any MOPR changes intended to be effective by PJM RPM 2016/17 auction

Regulatory advocacy efforts are designed to improve the functioning of competitive markets and protect against attempts to undermine price signals

ERCOT Market Redesign

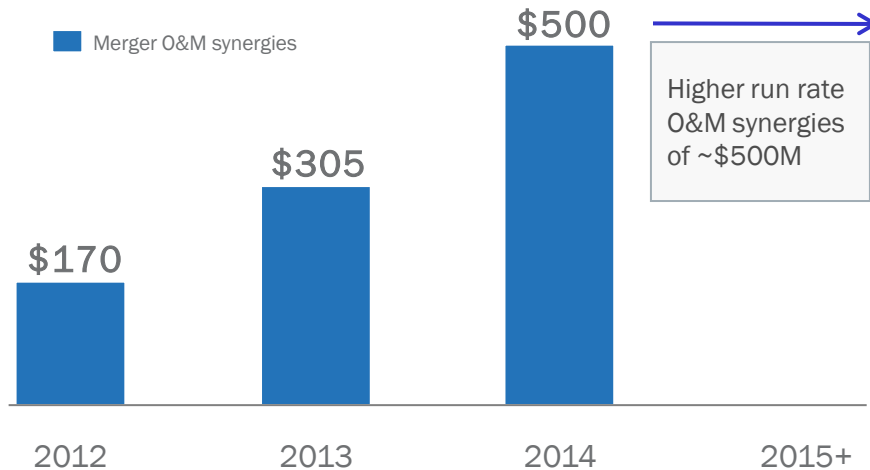
Option	Overview	Easy to Implement	Risk of Reliability Issues	Incentivizes New Build
1: Energy-Only with Market-Based Reserve Margin	Market determines reliability levels and investment decisions on energy prices alone (current state)	Yes	High	No
2: Energy-Only with Adders to Support a Target Reserve Margin	Potential options include: <ul style="list-style-type: none"> • increasing the system offer caps • establishing an LMP adder 	Yes	Medium	No
3: Energy-Only with Backstop Procurement at Minimum Acceptable Reliability	Allows for ERCOT to reactivate mothballed capacity under RMR agreements and procure emergency demand resources at the price cap	Yes	Low	No
4: Mandatory Resource Adequacy Retirement for LSEs	LSEs would be required to obtain enough capacity to meet peak load plus reserve margin or face penalty	No	Low	Yes
5: Resource Adequacy Requirement with Centralized Forward Capacity Market	<ul style="list-style-type: none"> • PJM style capacity market • Forward capacity obligations are procured on behalf of load 3-4 years prior to delivery 	No	Low	Yes

Exelon is well positioned in ERCOT for any of the new market constructs

APPENDIX

Achievable Merger Synergies

O&M Savings⁽¹⁾ (\$M)



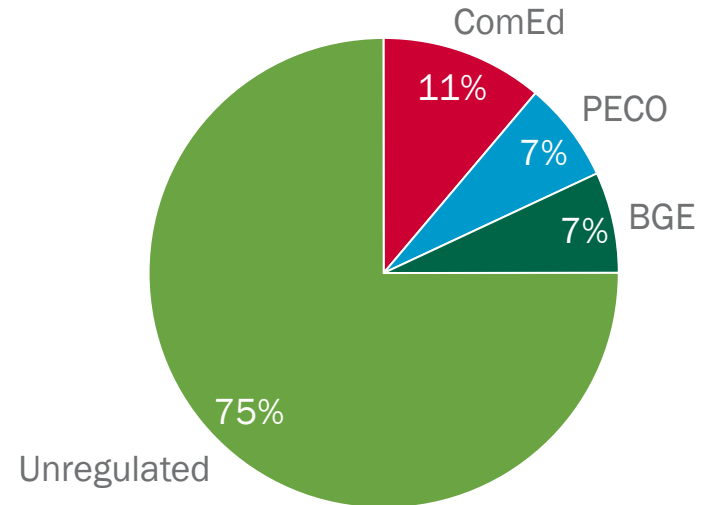
Gross Margin Opportunities (\$M)

- Run rate gross margin opportunities of \$100M⁽²⁾ starting in 2014
 - Matching load and generation
 - Retail growth opportunities
 - Portfolio optimization

(1) O&M synergies include cost savings of ~\$40M from lower liquidity requirements.

(2) Gross margin opportunities included in Total Gross Margin shown on slide 16.

Run Rate O&M Synergies Breakdown



- Key drivers of run rate O&M synergies include
 - Labor savings from corporate and commercial consolidations
 - Reduced collateral requirements
 - IT systems consolidation
 - Supply chain savings
 - Other non-labor corporate synergies

Fully committed to achieving merger synergies

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%

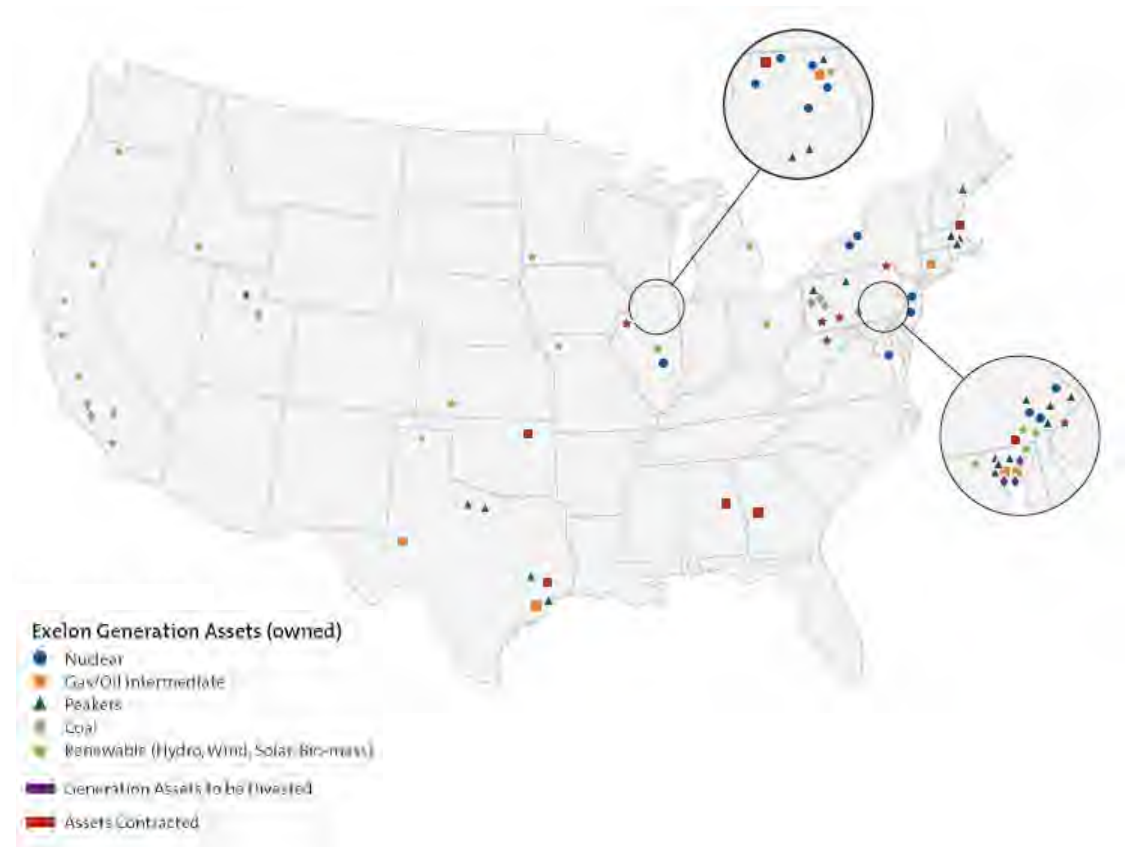
Timeline

- 10/12/12: Staff/Intervenors file direct testimony
- 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

- Power generation assets in 20 states and Canada

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

- One of nation's cleanest fleets as measured by CO₂, SO₂ and NO_x intensity



Generation fleet uniquely diversified across regions and technologies

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Growing Clean Generation with Upgrades

Nuclear Uprate Program Summary⁽¹⁾

	Estimated IRR	Overnight Cost ⁽²⁾	Approval Process	Project Duration
Megawatt Recovery & Component Upgrades	11-14%	\$860 M	Not required	3-4 Years
MUR (Measurement Uncertainty Recapture)	12-16%	\$340 M	Straight forward approval process	2-3 Years
EPU (Extended Power Uprate)	9-13%	\$2,260 M	Straight forward approval process	3-6 Years

Executing uprate projects across our geographically diverse nuclear fleet – planned to add 85 MW's in 2012

Station	Base Case MW ⁽³⁾	Max Potential MW ⁽³⁾	MW Online to Date	Year of Full Operation by Unit ⁽⁴⁾
MW Recovery & Component Upgrades:				
Quad Cities	99	99	99	2011 / 2010
Dresden	3	3		2013 / 2012
Peach Bottom	29	30	15	2011 / 2012
Dresden	106	110	62	2011 / 2013
Limerick	6	6	3	2012 / 2013
Peach Bottom	2	2		2014 / 2015
MUR:				
LaSalle	39	39	39	2010 / 2011
Limerick	30	30	30	2011 / 2011
Braidwood	34	42		2012 / 2012
Byron	34	42		2012 / 2012
Quad Cities	21	23		2014 / 2014
Dresden	28	31		2014 / 2015
TMI	12	15		2014
EPU:				
Clinton	2	2	2	2010
Peach Bottom	130	137		2015 / 2016
LaSalle	303	336		2018 / 2017
Limerick	306	340		2016 / 2017
Total	1,184	1,287	250	

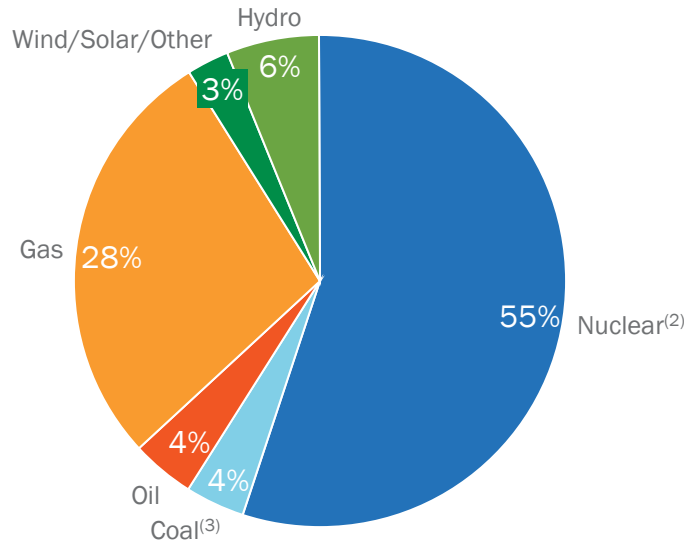
(1) Includes deferral of LaSalle EPU.

(2) In 2012 dollars. Overnight costs do not include financing costs or cost escalation.

(3) Adjusted for actual MW's achieved.

Well Positioned for Clean Air Rules

Combined Company Portfolio



Total Generation Capacity⁽¹⁾: ~ 34,660 MW

- Largest clean merchant generation portfolio in the nation
- Less than 5% of combined generation capacity will require capital expenditures to comply with Air Toxic rules
 - Approx. \$200 million of CapEx, majority of which is at Conemaugh (Exelon ownership share ~31%)
- Low-cost generation capacity provides unparalleled leverage to rising commodity prices

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

(1) Total owned generation capacity as of 4/30/2012 for legacy Exelon and legacy Constellation combined, net of physical market mitigation of 2,648 MW.

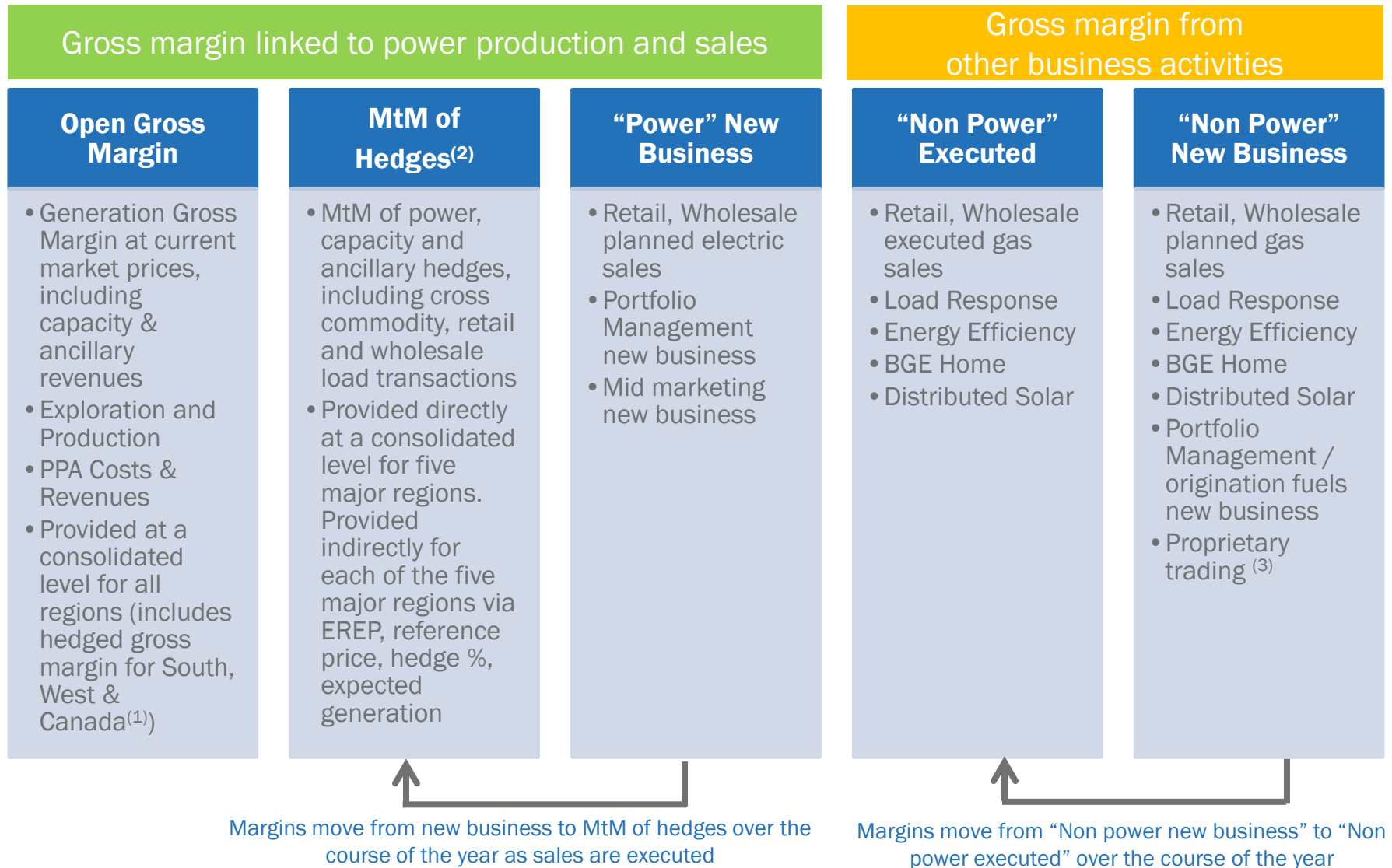
(2) Nuclear capacity shown above reflects EXC ownership of CENG and Salem.

(3) Coal capacity shown above does not include Eddystone 2 (309 MW) retired on 6/1/2012.

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) ⁽¹⁾	2012 ⁽²⁾	2013	2014
Open Gross Margin (including South, West & Canada hedged GM) ^(3,4)	\$4,450	\$5,400	\$5,850
Mark to Market of Hedges ⁽⁵⁾	\$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
Total Gross Margin	\$8,050	\$8,200	\$7,900

Reference Prices ⁽⁶⁾	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 divested in 2012.

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

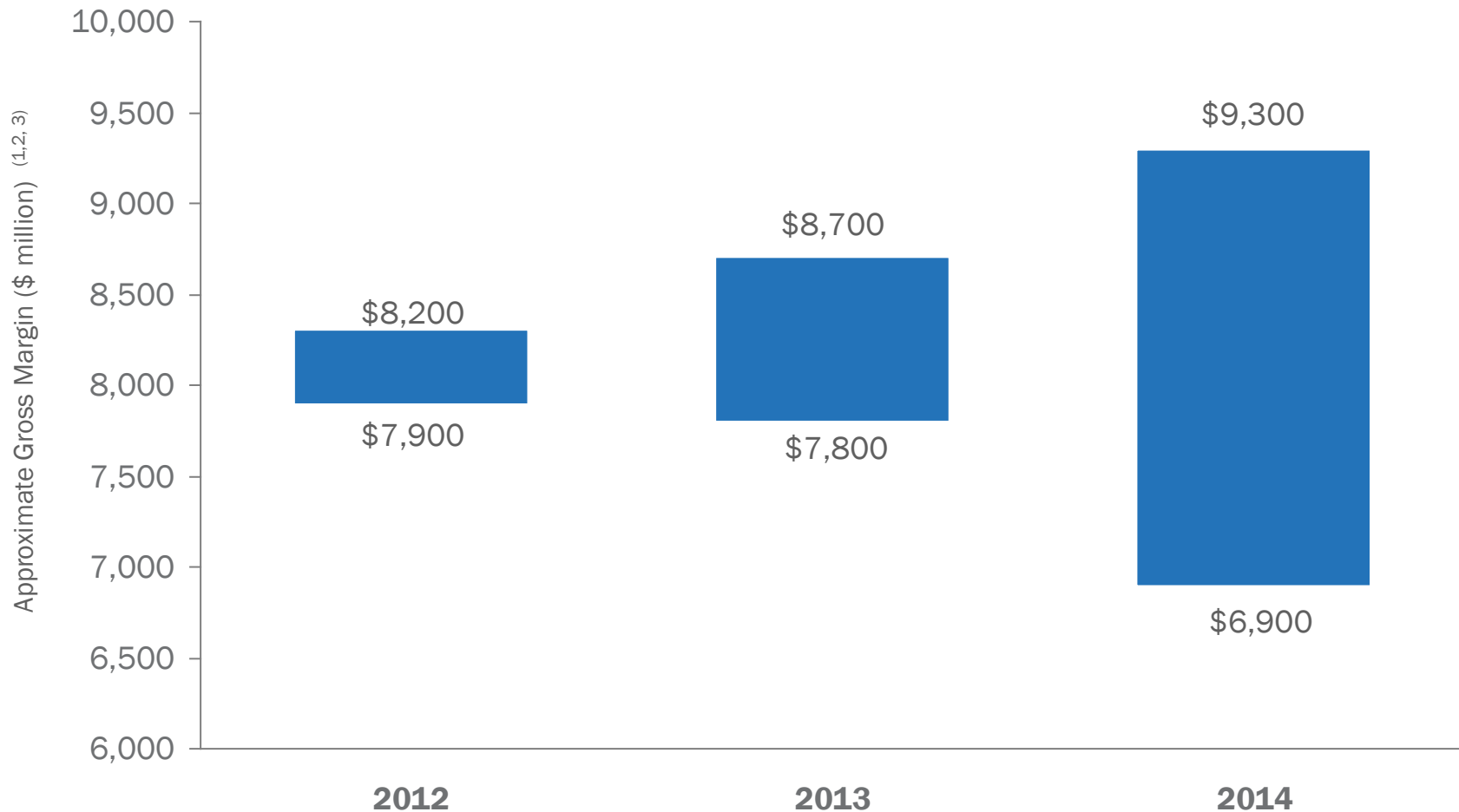
(1) Stub period calculated by excluding Jan 2012 thru mid-March 2012 for Constellation only. (2) Excludes Maryland divested in 2012. (3) Includes CENG Joint Venture. (4) Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted for capacity. 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) ^(1,4)	2012	2013	2014
Henry Hub Natural Gas (\$/MMbtu) ⁽²⁾			
+ \$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 ⁽²⁾			
+ \$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 ⁽³⁾			
+/- 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 divested in 2012. (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 divested in 2012.

Illustrative Example of Modeling Exelon Generation 2013 Gross Margin

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Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	<div> <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) ⁽¹⁾	\$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.