

Investor Meetings

September 2012



Cautionary Statements Regarding Forward-Looking Information

ZECJ-FIN-21

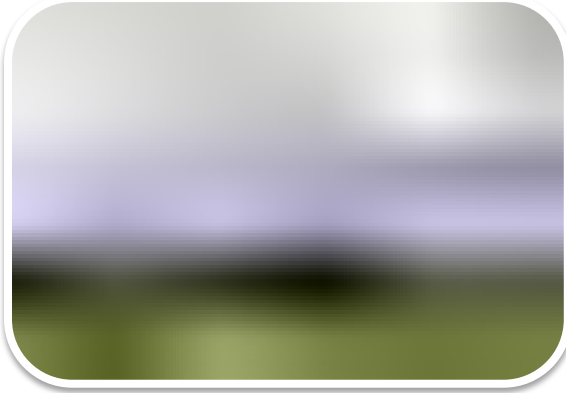
PUBLIC

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.

Exelon Overview

Exelon Generation

Power Generation



Constellation



Exelon Utilities

ComEd, PECO & BGE



- Largest merchant fleet in the nation (~35 GW of capacity), with unparalleled upside
- One of the largest and best managed nuclear fleets in the world (~19 GW)
- Significant gas generation capacity (~10 GW)
- Renewable portfolio (~1 GW), mostly contracted

- Leading competitive energy provider in the U.S.
- Customer-facing business, with ~1.1 M competitive customers and large wholesale business
- Top-notch portfolio and risk management capabilities
- Extensive suite of products including Load Response, RECs, Distributed Solar

- One of the largest electric and gas distribution companies in the nation ~6.6 M customers
- Diversified across three utility jurisdictions – Illinois, Maryland and Pennsylvania
- Significant investments in Smart Grid technologies
- Transmission infrastructure improvement at utilities

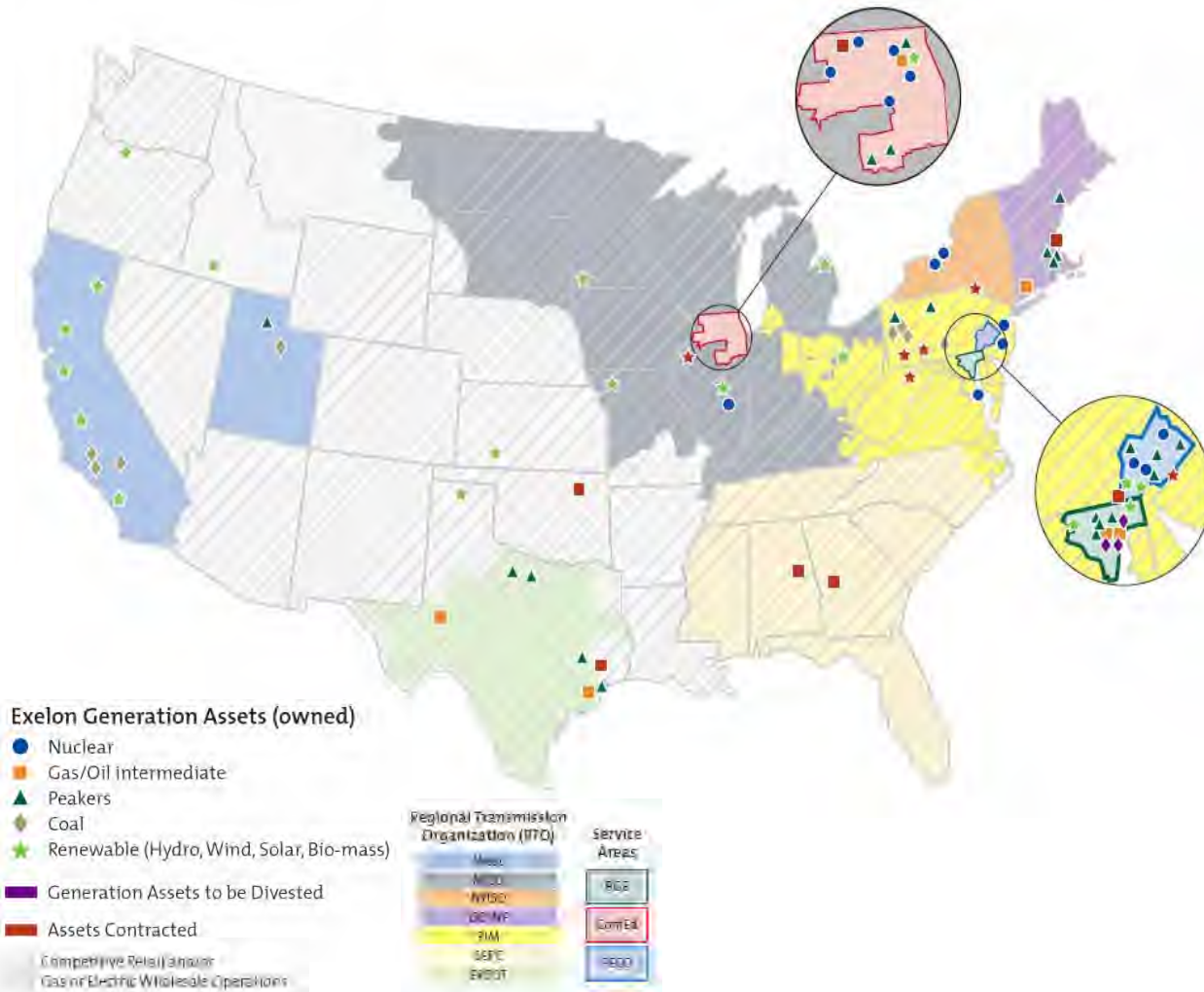
Competitive Business

Regulated Business

Exelon is the largest competitive integrated energy company in the U.S.

National Scope

National presence gives us a unique platform to perform and grow



Power Generation

Operations in seven RTOs, with strong positions across PJM, ERCOT & New England

Constellation

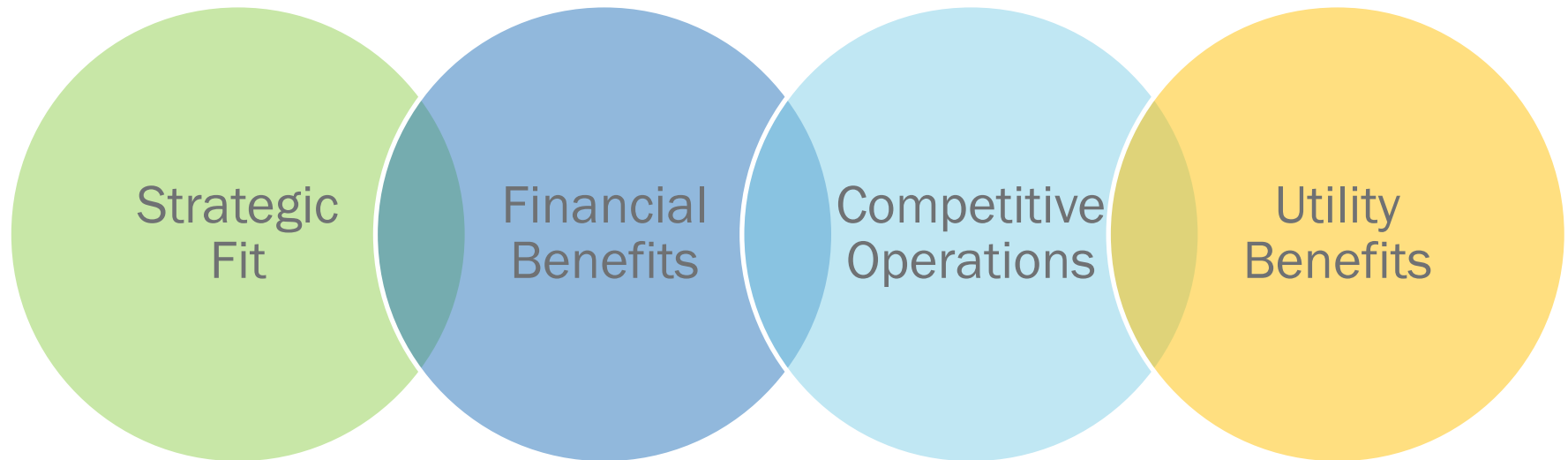
Serves more than 2/3rds of the Fortune 100 companies in the U.S.

Exelon Utilities

Large urban presence with operations in three states – IL, PA and MD

Coast-to-coast presence with operations in 47 states and Canada

Multiple Merger Benefits

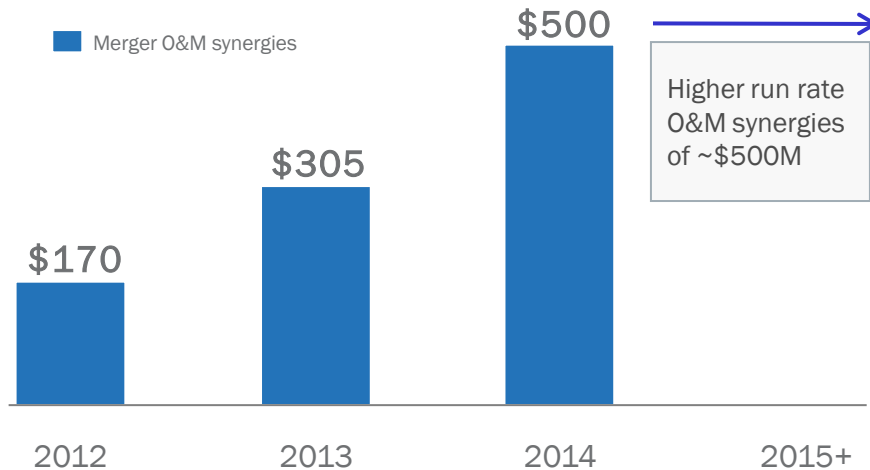


- Matches Exelon's clean generation fleet with Constellation's customer-facing leading retail and wholesale platform
- Creates economies of scale through expansion across the value chain
- Earnings and cash flow accretive
- Stronger balance sheet than standalone financials
- Significant cost synergies and gross margin expansion
- Regional and technological diversification
- Maintain clean generation profile
- More competitive product offerings and enhanced margins
- Scalable commercial platform
- Maintains a regulated earnings profile
- Enables operational enhancements from sharing best practices

This merger creates incremental strategic and financial value

Achievable Merger Synergies

O&M Savings⁽¹⁾ (\$M)



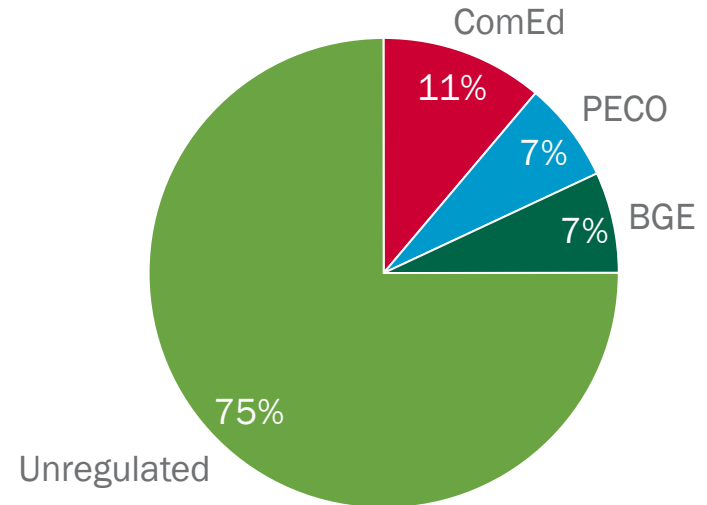
Gross Margin Opportunities (\$M)

- 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 45.

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

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

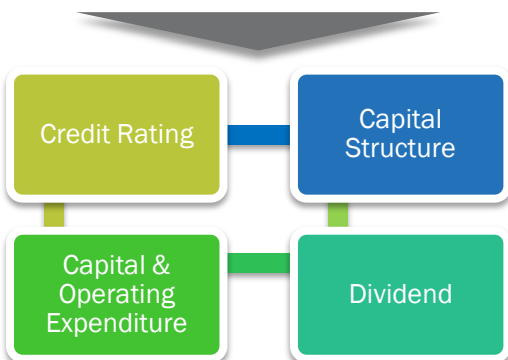
- Ensure stability in near-term cash flows and earnings
- Disciplined approach to hedging
- Tenor aligns with customer preferences and market liquidity
- Multiple channels to market that allow us to maximize margins
- Large open position in outer years to benefit from price upside

Bull / Bear Program

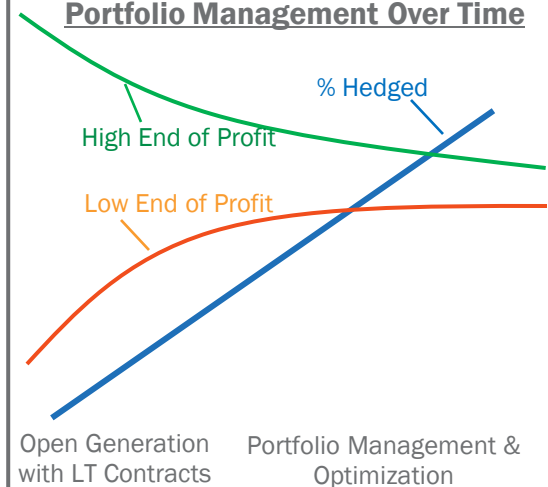
- Ability to exercise fundamental market views to create value within the ratable framework
- Modified timing of hedges versus purely ratable
- Cross-commodity hedging (heat rate positions, options, etc.)
- Delivery locations, regional and zonal spread relationships

Align Hedging & Financials

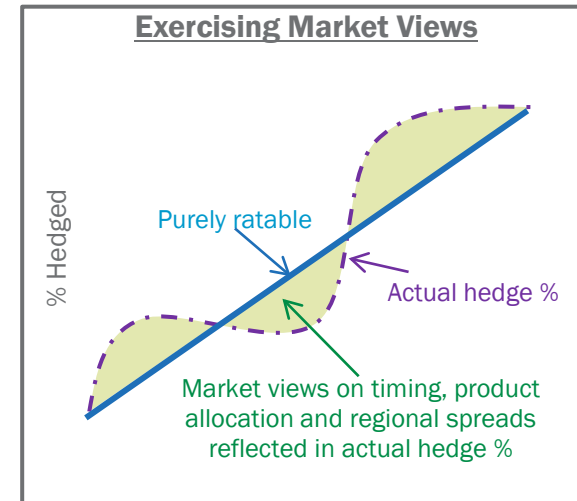
Establishing Minimum Hedge Targets



Portfolio Management Over Time



Exercising Market Views



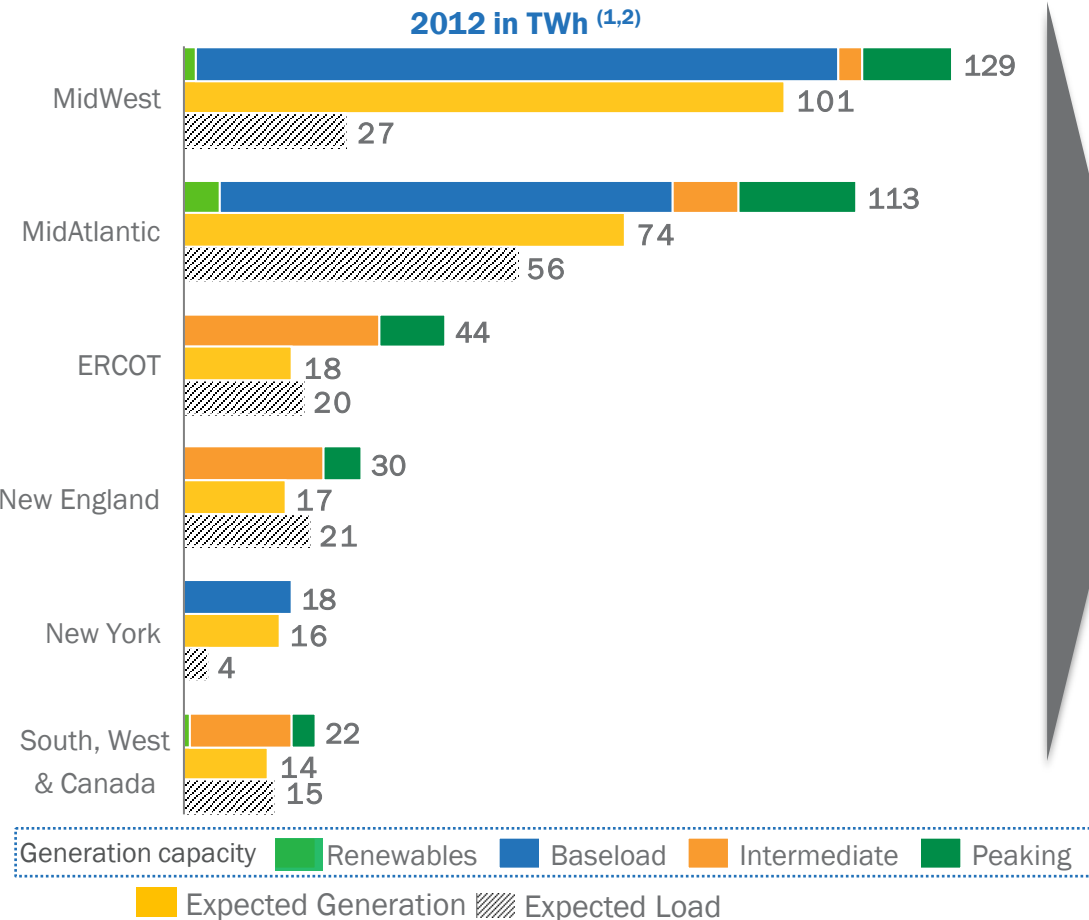
Protect Balance Sheet

Ensure Earnings Stability

Create Value

Generation and Load Match

Generation Capacity, Expected Generation and Expected Load



Generation & Load Match: Competitive Advantage

Our generation portfolio is low cost, flexible and diverse

Generation and load positions are well balanced across multiple regions

Adequate intermediate and peaking capacity within the portfolio for managing peaking load

Continue to buy or sell length from market to manage portfolio needs

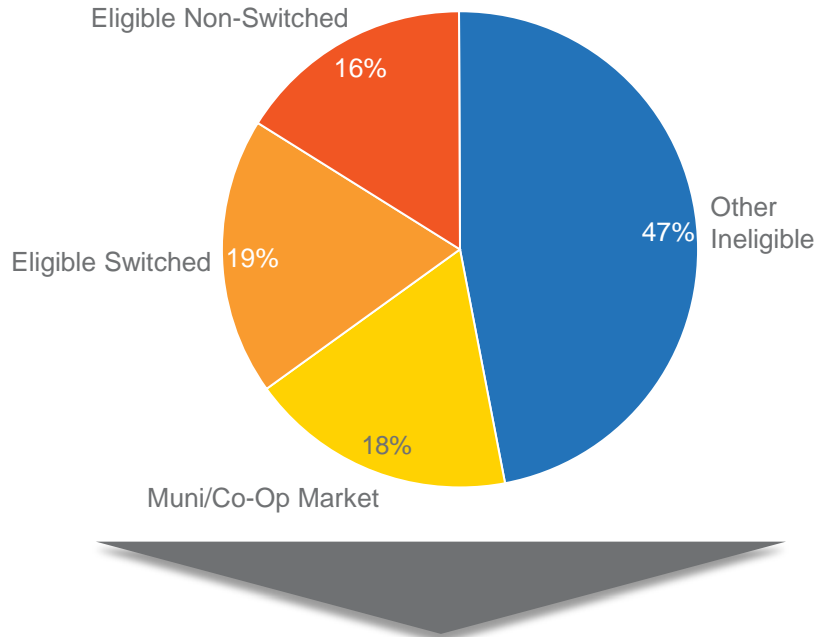
The combination establishes an industry-leading platform with regional diversification of the generation fleet and customer-facing load business

- (1) Owned and contracted generation capacity converted from MW to MWh assuming 100% capacity factor for all technology types, except for renewable capacity which is shown at estimated capacity factor.
 (2) Expected generation and load shown in the chart above will not tie out with load volume and ExGen disclosures. Load shown above does not include indexed products and generation reflects a net owned and contracted position. Estimates as of 4/30/2012.

Electric Load Serving 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

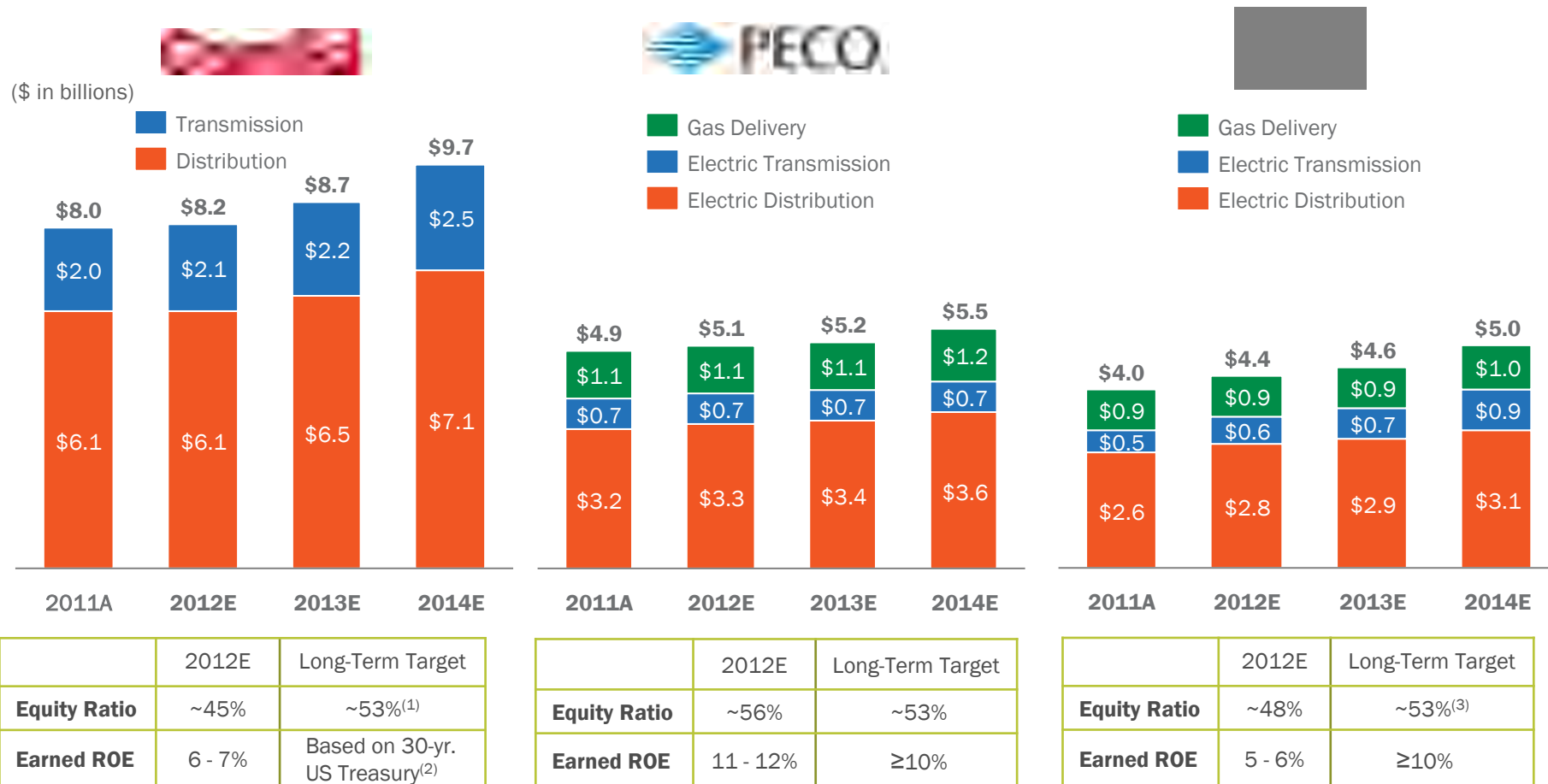
Strategy to Grow

- 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.

Rate Base and ROE Targets



Smart meter and smart grid investment will be a key driver of rate base growth

(1) Equity component for distribution rates will be the actual capital structure adjusted for goodwill.

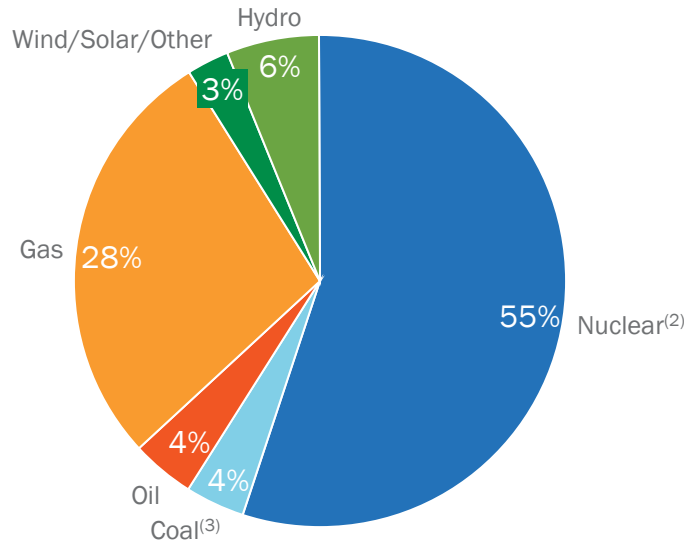
(2) Earned ROE will reflect the weighted average of 11.5% allowed transmission ROE and distribution ROE resulting from 30-year Treasury plus 580 basis points for each calendar year.

(3) Per MDPSC merger commitment, BGE is precluded from paying dividends through 2014. Per MDPSC orders, BGE cannot pay out a dividend to its parent company if said dividend would cause BGE's equity ratio to fall below 48%.

Note: ComEd distribution rate base represents an average and transmission rate base represents end of year; PECO rate base represents end-of-year; and BGE rate base represents a trailing 13-month average. Numbers may not add due to rounding.

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 assumed to be 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.

Exelon Nuclear Fleet Overview (including CENG and Salem)

	Plant Location	Type/ Containment	Water Body	License Extension Status / License Expiration ⁽¹⁾	Ownership	Spent Fuel Storage/ Date to lose full core discharge capacity ⁽²⁾
Midwest	Braidwood, IL (Units 1 and 2)	PWR Concrete/Steel Lined	Kankakee River	Expect to file application in 2013 / 2026, 2027	100%	Dry Cask
	Byron, IL (Units 1 and 2)	PWR Concrete/Steel Lined	Rock River	Expect to file application in 2013 / 2024, 2026	100%	Dry Cask
	Clinton, IL (Unit 1)	BWR Concrete/Steel Lined / Mark III	Clinton Lake	2026	100%	2018
	Dresden, IL (Units 2 and 3)	BWR Steel Vessel / Mark I	Kankakee River	Renewed / 2029, 2031	100%	Dry Cask
	LaSalle, IL (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	Illinois River	2022, 2023	100%	Dry Cask
	Quad Cities, IL (Units 1 and 2)	BWR Steel Vessel / Mark I	Mississippi River	Renewed / 2032	75% Exelon, 25% Mid- American Holdings	Dry Cask
Mid-Atlantic	Calvert Cliffs, MD (Units 1 and 2)	PWR Concrete/Steel Lined	Chesapeake Bay	Renewed / 2034, 2036	100% CENG ⁽⁴⁾	Dry Cask
	R.E. Ginna, NY (Unit 1)	PWR Concrete/Steel Lined	Lake Ontario	Renewed / 2029	100% CENG ⁽⁴⁾	Dry Cask
	Limerick, PA (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	Schuylkill River	Filed application in June 2011 (decision expected in 2013) / 2024, 2029	100%	Dry Cask
	Nine Mile Point, NY (Units 1 and 2)	BWR Concrete/Steel Vessel / Mark I / Concrete/Steel Vessel/ Mark II	Lake Ontario	Renewed / 2029, 2046	100% CENG ⁽⁴⁾ / 82% CENG ⁽⁴⁾ , 18% Long Island Power Authority	Dry Cask (Summer 2012)
	Oyster Creek, NJ (Unit 1)	BWR Steel Vessel / Mark I	Barnegat Bay	Renewed / 2029 ⁽³⁾	100%	Dry Cask
	Peach Bottom, PA (Units 2 and 3)	BWR Steel Vessel / Mark I	Susquehanna River	Renewed / 2033, 2034	50% Exelon, 50% PSEG	Dry Cask
	TMI, PA (Unit 1)	PWR Concrete/Steel Lined	Susquehanna River	Renewed / 2034	100%	2023
	Salem, NJ (Units 1 and 2)	PWR Concrete/Steel Lined	Delaware River	Renewed / 2036, 2040	42.6% Exelon, 57.4% PSEG	Dry Cask

(1) Operating license renewal process takes approximately 4-5 years from commencement until completion of NRC review.

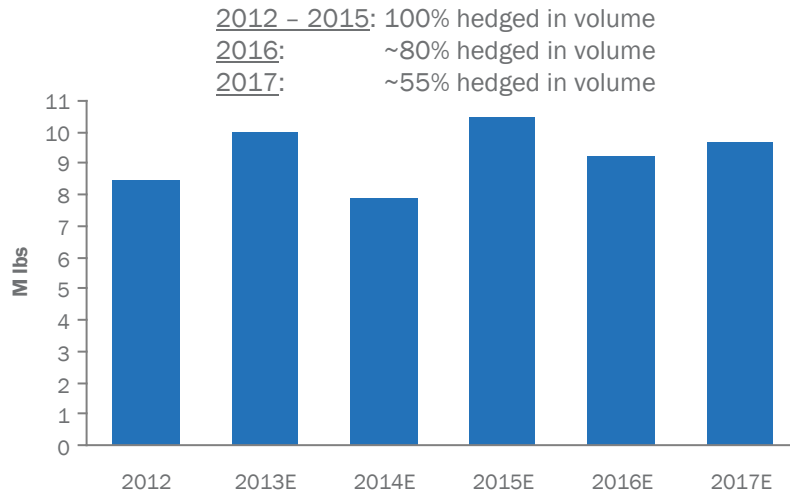
(2) The date for loss of full core reserve identifies when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core. Dry cask storage will be in operation at those sites prior to losing full core discharge capacity in their on-site storage pools.

(3) On December 8, 2010, Exelon announced that it will permanently cease generation operations at Oyster Creek by December 31, 2019. Oyster Creek's current NRC license expires in 2029.

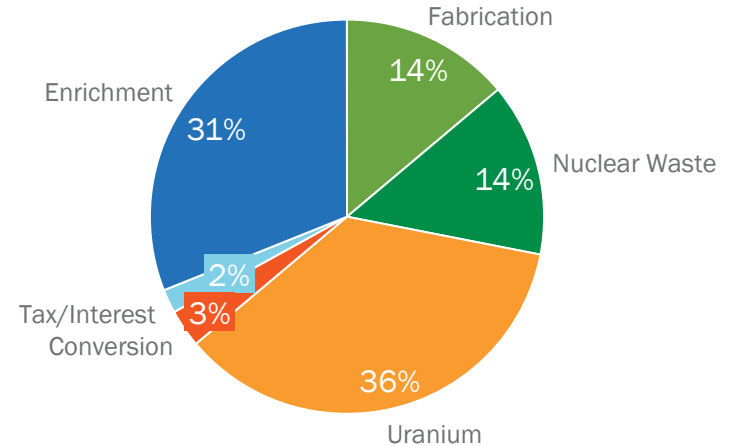
(4) Exelon Generation has a 50.01% ownership interest in CENG (Constellation Energy Nuclear Group, LLC). Electricite de France SA (EDF) has a 49.99% ownership interest in CENG.

Effectively Managing Nuclear Fuel Costs⁽¹⁾

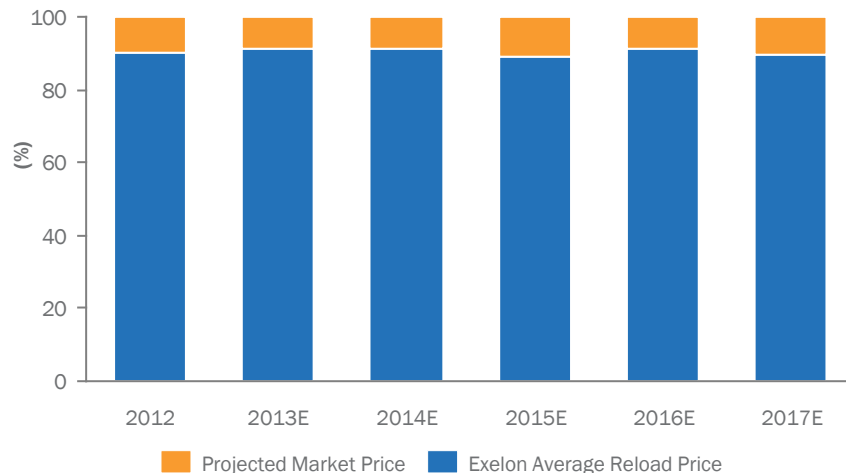
Projected Exelon (100%) Uranium Demand



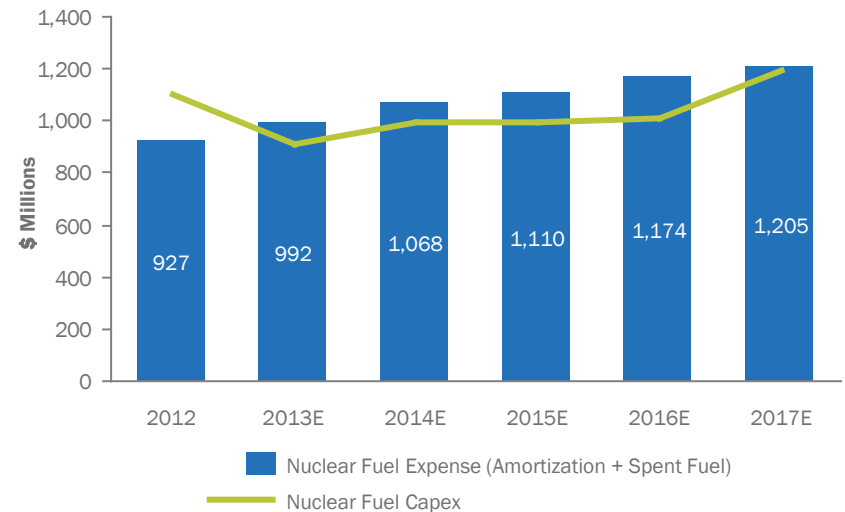
Components of Fuel Expense in 2012



Projected Exelon Average Uranium Cost vs. Market



Projected Total Nuclear Fuel Spend⁽²⁾



(1) All charts exclude Salem and CENG.

(2) At ownership, excluding Salem and CENG. Excludes costs reimbursed under the settlement agreement with the DOE. Data assumes LaSalle's deferral of EPU.

Exelon Generation Fleet Overview⁽¹⁾

Plant	Location	Owned Capacity (MW)	LDA	Hub/Zone	Region for Disclosure Mapping
Nuclear					
Braidwood	Braidwood, IL	2,348	Rest of RTO	NIHub	Midwest
Byron	Byron, IL	2,323	Rest of RTO	NIHub	Midwest
Calvert Cliffs I and II	Calvert Co, MD	853	SWMAAC	BGE	Mid-Atlantic
Clinton	Clinton, IL	1,067	n/a	Indiana Hub	Midwest
Dresden	Morris, IL	1,753	Rest of RTO	NIHub	Midwest
LaSalle	Seneca, IL	2,316	Rest of RTO	NIHub	Midwest
Limerick	Limerick Twp., PA	2,312	EMAAC	PECO Zone	Mid-Atlantic
Nine Mile Point I and II	Scriba, NY	782	NYPP	Zone C	New York
Oyster Creek	Forked River, NJ	625	EMAAC	PECO Zone	Mid-Atlantic
Peach Bottom	Peach Bottom Twp., PA	1,150	EMAAC	PECO Zone	Mid-Atlantic
Quad Cities	Cordova, IL	1,380	Rest of RTO	NIHub	Midwest
R.E. Ginna	Ontario, NY	291	NYPP	Zone B	New York
Salem	Hancock's Bridge, NJ	1,004	EMAAC	PECO Zone	Mid-Atlantic
Three Mile Island	Londonderry Twp, PA	837	MAAC	Whub/MetEd Zone	Mid-Atlantic
Coal⁽²⁾					
ACE	Trona, CA	32		n/a	Other
Conemaugh	New Florence, PA	533	MAAC	Whub/Penelec Zone	Mid-Atlantic
Jasmin	Kern Co, CA	18		n/a	Other
Keystone	Shelocta, PA	716	MAAC	Whub/Penelec Zone	Mid-Atlantic
POSO	Kern Co, CA	18		n/a	Other
Gas					
Colorado Bend	Wharton, TX	550		Houston	ERCOT
Eddystone 3, 4	Eddystone, PA	760	EMAAC	PECO Zone	Mid-Atlantic
Fore River	North Weymouth, MA	688	ROP-NE	Hub	New England
Gould Street	Baltimore City, MD	97	SWMAAC	BGE	Mid-Atlantic
Grande Prairie	Alberta, Canada	93		n/a	Other
Handley 3, 4, 5	Fort Worth, TX	1,265		ERCOT N	ERCOT
Handsome Lake	Rockland Twp, PA	268	MAAC	Whub/Penelec Zone	Mid-Atlantic
Hillabee Energy	Alexander City, Alabama	740		GTC	Other
LaPorte	Laporte, TX	152		ERCOT	ERCOT
Medway	West Medway, MA	105	ISO-NE	Mass Hub	New England
Mountain Creek 6, 7, 8	Dallas, TX	805		ERCOT N	ERCOT
Mystic 7	Charlestown, MA	560	ROP-NE	Hub	New England
Mystic 8,9	Charlestown, MA	1,398	NEMA	Hub	New England
Notch Cliff	Baltimore Co, MD	101	SWMAAC	BGE	Mid-Atlantic
Perryman - Gas	Harford Co, MD	147	SWMAAC	BGE	Mid-Atlantic
Quail Run Energy	Odessa, TX	550		West	ERCOT
Riverside - Gas	Baltimore Co, MD	189	SWMAAC	BGE	Mid-Atlantic
Southeast Chicago	Chicago, IL	296	Rest of RTO	NIHub	Midwest
West Valley	Salt Lake City, UT	200		n/a	Other
Westport	Baltimore Co, MD	116	SWMAAC	BGE	Mid-Atlantic
Wolf Hollow 1, 2, 3	Granbury, TX	705		ERCOT N	ERCOT

Plant	Location	Owned Capacity (MW)	LDA	Hub/Zone	Region for Disclosure Mapping
Oil					
Chester	Chester, PA	39	EMAAC	PECO Zone	Mid-Atlantic
Conemaugh	New Florence, PA	2	MAAC	Whub/Penelec Zone	Mid-Atlantic
Croydon	Bristol Twp., PA	391	EMAAC	PECO Zone	Mid-Atlantic
Delaware	Philadelphia, PA	56	EMAAC	PECO Zone	Mid-Atlantic
Eddystone	Eddystone, PA	60	EMAAC	PECO Zone	Mid-Atlantic
Falls	Falls Twp., PA	51	EMAAC	PECO Zone	Mid-Atlantic
Framingham	Framingham, MA	28	ISO-NE	Mass Hub	New England
Keystone	Shelocta, PA	2	MAAC	Whub/Penelec Zone	Mid-Atlantic
Moser	Lower Pottsgrove Twp., PA	51	EMAAC	PECO Zone	Mid-Atlantic
Mystic Jet	Charlestown, MA	9	ROP-NE	Hub	New England
New Boston	South Boston, MA	12	ISO-NE	Mass Hub	New England
Perryman - Oil	Harford Co, MD	200	SWMAAC	BGE	Mid-Atlantic
Philadelphia Road	Baltimore Co, MD	61	SWMAAC	BGE	Mid-Atlantic
Richmond	Philadelphia, PA	98	EMAAC	PECO Zone	Mid-Atlantic
Riverside - Oil	Baltimore Co, MD	39	SWMAAC	BGE	Mid-Atlantic
Salem	Hancock's Bridge, NJ	16	EMAAC	PECO Zone	Mid-Atlantic
Schuylkill	Philadelphia, PA	199	EMAAC	PECO Zone	Mid-Atlantic
Southwark	Philadelphia, PA	52	EMAAC	PECO Zone	Mid-Atlantic
Wyman	Yarmouth, ME	36	ISO-NE	Maine Zone	New England
Hydro					
Conowingo	Harford Co., MD	572	EMAAC	PECO Zone	Mid-Atlantic
Malacha	Muck Valley, CA	16		n/a	Other
Muddy Run	Lancaster, PA	1,070	EMAAC	PECO Zone	Mid-Atlantic
Safe Harbor	Safe Harbor, PA	278	MAAC	Whub	Mid-Atlantic
Wind					
AgriWind	Bureau Co., IL	8		IL Hub/Indiana Hub	Midwest
Blue Breezes	Faribault Co., MN	3		MinnHub	Midwest
Bluegrass Ridge	Gentry Co., MO	56		SERC	Other
Brewster	Jackson Co., MN	6		MinnHub	Midwest
Cassia	Twin Falls Co., ID	29		WECC/Mid-C	Other
Cisco	Jackson Co., MN	8		MinnHub	Midwest
Conception	Nodaway Co., MO	50		SERC	Other
Cow Branch	Atchinson Co., MO	50		SERC	Other
Cowell	Pipestone Co., MN	2		MinnHub	Midwest
CP Windfarm	Faribault Co., MN	4		MinnHub	Midwest
Criterion	Oakland, MD	70		Whub	Mid-Atlantic
Echo 1	Umatilla Co., OR	34		WECC/Mid-C	Other
Echo 2,3	Morrow Co., OR	30		WECC/Mid-C	Other
Ewington	Jackson Co., MN	20		MinnHub	Midwest
Exelon Wind 1-11	Various Counties, TX	180		SPP	Other
Greensburg	Kiowa Co., KS	13		SPP	Other
Harvest	Huron Co., MI	53		MichHub	Midwest

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

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

Exelon Generation Fleet Overview (cont'd)⁽¹⁾

Plant	Location	Owned Capacity (MW)	LDA	Hub/Zone	Region for Disclosure Mapping
Wind (cont'd)					
High Plains	Moore Co., TX	10		SPP	Other
Loess Hills	Atchinson Co., MO	5		SERC	Other
Marshall	Lyon Co., MN	19		MinnHub	Midwest
Michigan Wind 1 and 2	Bingham Twp., MI	159		MichHub	Midwest
Mountain Home	Elmore Co., ID	40		WECC/Mid-C	Other
Norgaard	Lincoln Co., MN	9		MinnHub	Midwest
Threemile Canyon	Morrow Co., OR	10		WECC/Mid-C	Other
Tuana Springs	Twin Falls Co., ID	17		WECC	Other
Wolf	Nobles Co., MN	6		n/a	Midwest
Solar					
City Solar	Chicago, IL	10	Rest of RTO	NIHub	Midwest
Constellation Solar	Various	84		n/a	Other
SEGS IV-VI	Kramer Junction, CA	8		n/a	Other
Biomass					
Chinese Station	Jamestown, CA	10		n/a	Other
Fresno	Fresno, CA	12		n/a	Other
Rocklin	Placer Co, CA	12		n/a	Other
Landfill Gas					
Fairless Hills	Falls Twp, PA	60	EMAAC	PECO Zone	Mid-Atlantic
Pennsbury	Falls Twp., PA	6	EMAAC	PECO Zone	Mid-Atlantic
Waste Coal					
Colver	Colver Township, PA	26		n/a	Mid-Atlantic
Panther Creek	Nesquehoning, PA	40		n/a	Mid-Atlantic
Sunnyside	Sunnyside, UT	26		n/a	Other
Total, Net of Physical Mitigation⁽¹⁾		34,662			
Physical Market Mitigation					
Brandon Shores	Anne Arundel Co, MD	1,273	SWMAAC	BGE	Mid-Atlantic
H. A. Wagner	Anne Arundel Co, MD	976	SWMAAC	BGE	Mid-Atlantic
C. P. Crane	Anne Arundel Co, MD	399	SWMAAC	BGE	Mid-Atlantic

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

Barclays CEO Energy-Power Conference

Jack Thayer, EVP & Chief Financial Officer

September 5, 2012



Market Fundamentals – Exelon's Macro View on the Economy

Current & Near Term 2012 & 2013

GDP growth at 2% or less in 2012 and 2013

Housing starts at ~500 thousand units / year

Unemployment expected to stay over 8%

Oil prices in the \$100/bbl range

Load growth is flat

Medium to Long Term 2014 & Beyond

GDP growth in excess of 2.5% in 2014

Housing starts exceed 1 million units / year

Unemployment moves under 8%

Oil prices remain in the \$100/bbl range

Load growth is positive but at a rate lower
than GDP

Slow but positive growth in the near term will give way to higher growth levels in 2014 and beyond. This will result in higher gas and power demand, stabilizing prices in the short term and a positive trajectory going forward.

Market Fundamentals – Natural Gas Price Expectations

Current & Near Term 2012 & 2013

Market Dynamics

Steady production

Record warm winter in 2012 resulting in excess gas storage, partially offset by hot summer

Coal to gas switching reduces supply glut and provides market elasticity

Anticipated Price Range

\$2.00 - \$4.00 / mmbtu

Limited downside to gas prices from coal to gas switching

Medium to Long Term 2014 & Beyond

Market Dynamics

Declining production from oil drilling competition

Growing industrial demand

Increased transportation demand

Increased power generation demand

Potential for LNG exports

Anticipated Price Range

\$4.00 - \$6.00 / mmbtu

Limited downside to gas prices from increasing demand and market elasticity

We anticipate 2013 to be a transition year, with demand side pressures from a variety of factors coming into play in 2014 and beyond

Market Fundamentals – Expectations for Power Prices in PJM

Current & Near Term 2012 & 2013

Market Dynamics

No major impact on power prices from CSAPR¹ being vacated on power prices

~ 15 GW of retirements expected in latter half of 2012 and 2013

High heat rates in 2012 due to low gas prices and summer heat. Current forwards are fairly valued

Exelon Portfolio Impact⁴

Fully hedged in 2012, and >80% hedged in 2013

Medium to Long Term 2014 & Beyond

Market Dynamics

Low gas prices & MATS² rule are major drivers of coal retirements

~40 GW of coal retirements, with almost 70% already announced³. Includes ~25 GW of retirements in 2014 and 2015

Internal view of \$3-5/MWh upside in power prices not currently reflected in forward prices

Exelon Portfolio Impact⁴

53% open in 2014, and mostly open beyond 2014

Our baseload and intermediate generation fleet is well positioned and mostly open in 2015 to capture the upside in power prices

1. Cross State Air Pollution Rule

3. Retirement estimate is for the Eastern Interconnect as per Exelon's internal projections.

2. Mercury and Air Toxics Standards

4. Portfolio hedge percentages are shown as of 6/30/2012.

Market Fundamentals – Expected Upside in Power Prices

We believe PJM Power forwards do not fully reflect the upcoming changes in the generation supply stack

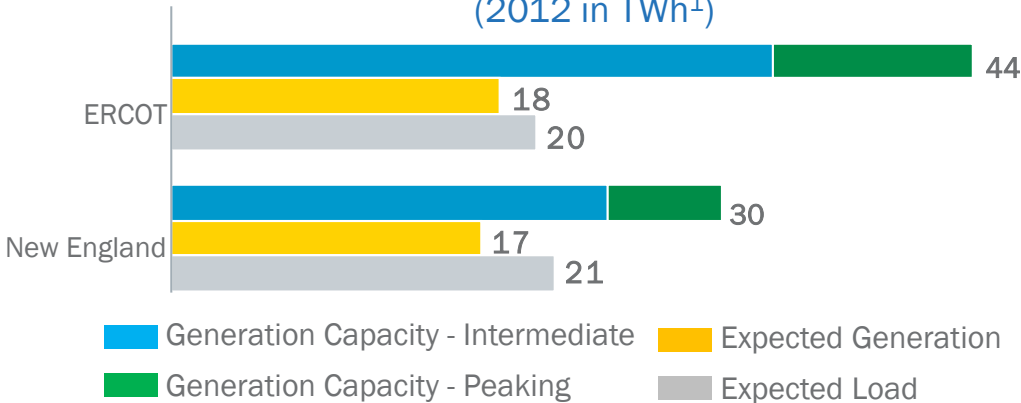
- **Supply stack changes driven by the following:**
 - ~18 GW of retirements in PJM by 2016
 - Increased compliance cost that will impact cost of operations for coal units that survive and increase their marginal cost
- **Contango¹ in gas market of ~\$0.80 cents from 2013 to 2017 results in a \$5/MWh increase in power prices at NIHUB**
 - We believe the higher power prices only reflect gas contango and not a restructuring of the generation stack
- **PJM Market View indicates the following:**
 - NIHUB has the most upside with ~1 heat rate point increase over current forward market
 - Some upside is already reflected in PJM-WHUB and we anticipate ~1/2 point heat rate increase
 - Significant amount of upside is already reflected in PJM-EHUB due to large number of gas units in that area

Expect power prices to move higher than gas prices resulting in higher heat rates

1. Contango refers to upward trajectory in forward prices. Data as of 7/30/2012.

Exelon's Texas and New England Portfolio

Generation Capacity, Expected Generation & Load
(2012 in TWh¹)



Generation Capacity²
(MW)

	ERCOT	New England
Intermediate	3,750	2,740
Peaking	1,260	710
Total	5,010	3,450

▪ Well balanced portfolio in Texas and New England

- Retail provides a lucrative channel to market our generation
- Intermediate and peaking generation assets are effectively call options at various heat rates that benefit from price volatility
- Leverage strong asset base and utilize market-based hedging instruments to effectively manage load-following obligations

▪ Premium asset location

- Sizeable generation position in TX close to large load pockets in Dallas and Houston
- Sizeable generation position in MA close to large load pockets in Boston

1. Data as of 06/30/2012. Owned and contracted capacity converted from MW to MWh assuming 100% capacity factor for all technology types, except renewables which are shown at estimated capacity factor.

2. Represents installed capacity owned or net contracted as of 6/30/2012. Capacity is rounded to the nearest 10 MW.

Asset Divestiture Update – Maryland Coal Assets

Units	Installed Capacity	Technology Type
Brandon Shores	1, 273 MW	2 coal units
C.P. Crane	399 MW	2 coal & 1 oil unit
H.A. Wagner	976 MW	2 coal, 2 oil & 1 dual fuel

Transaction Background and Overview

- Competitive sales process despite buyer restrictions due to market power considerations
- Cumulative cash proceeds of ~\$605 million
 - ~\$400 million sales price represents strong value for the assets in a challenging market environment
 - \$205 million tax benefit resulting from differences in sale proceeds versus tax basis
- Sale requires approval by FERC and DOJ - anticipate closing in the fourth quarter of this year
- Earnings and ExGen Disclosures
 - No impact on operating earnings or gross margins shown in ExGen disclosures

Earnings Conference Call 2nd Quarter 2012

August 1st, 2012



Second Quarter Performance and Full Year Guidance

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

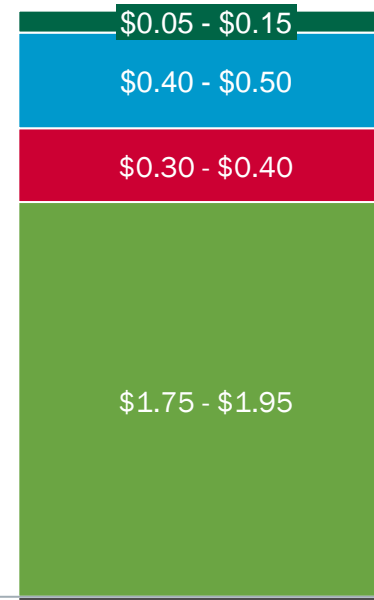
- Operating earnings in 2Q of \$0.61/share
- Nuclear capacity factor in 2Q of 93.4%
- Load serving business on course to meet volume and margin targets

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

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

2012 Earnings Guidance

\$2.55 - \$2.85⁽²⁾



FY 2012



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 19th, 2012 with hearings on August 3rd, 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 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) ⁽¹⁾	2012 ⁽²⁾	2013	2014	2012 ⁽²⁾	2013	2014
Open Gross Margin ^(2,3) (including South, West, Canada hedged gross margin)	\$4,450	\$5,400	\$5,850	\$4,300	\$5,800	\$6,250
Mark-to-Market of Hedges ⁽⁵⁾	\$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
Total Gross Margin	\$8,050	\$8,200	\$7,900	\$8,050	\$8,350	\$8,200

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)



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	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 ⁽⁴⁾					(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 ⁽⁵⁾	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 ⁽⁶⁾	25	250	25	(50)	75
Ending Cash Balance⁽¹⁾					\$750

(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.

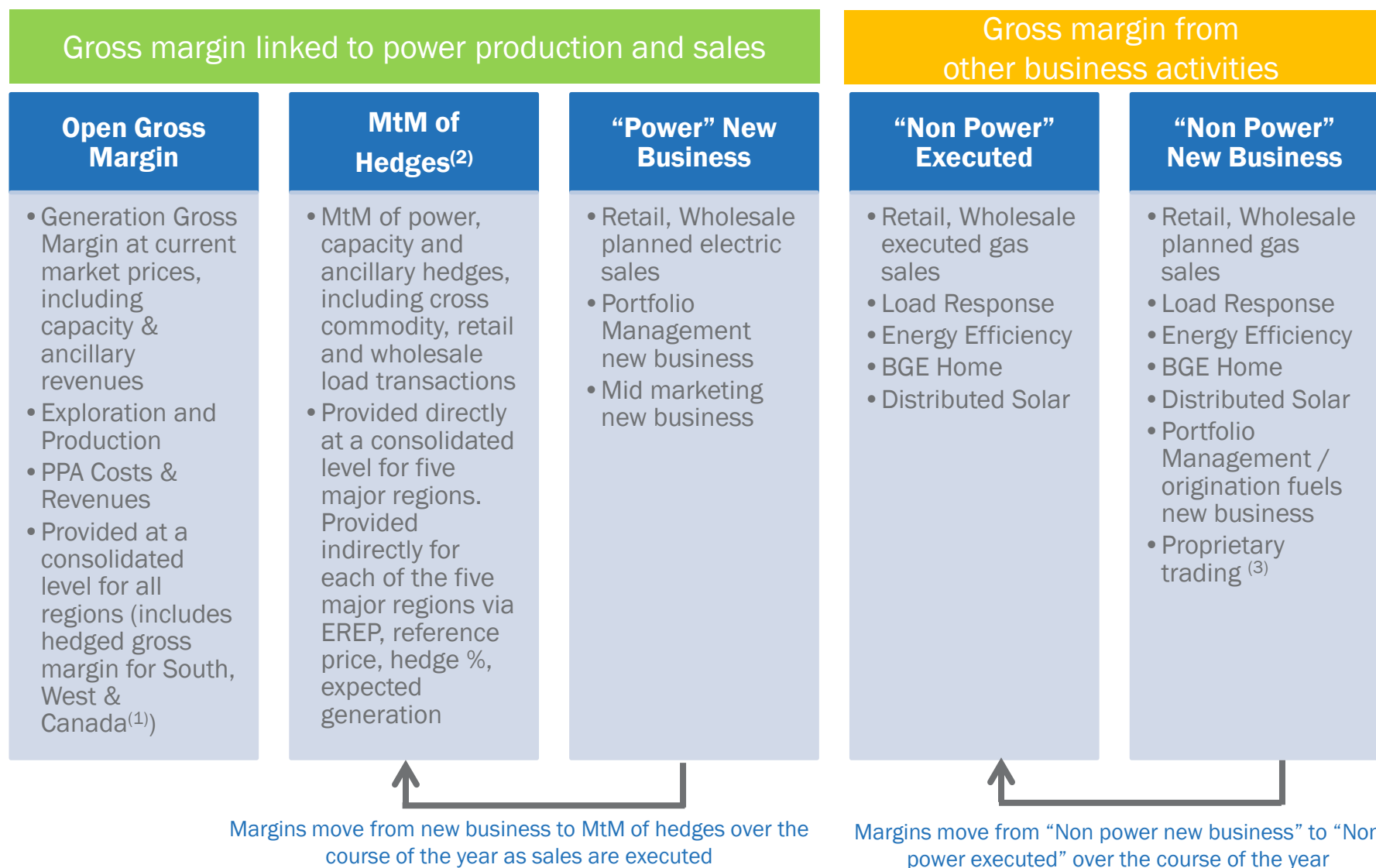
(7) Includes cash flow activity from Holding Company, eliminations, and other corporate entities. Represents Constellation cash flows from merger close through December 31, 2012.

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) ⁽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 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 ⁽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

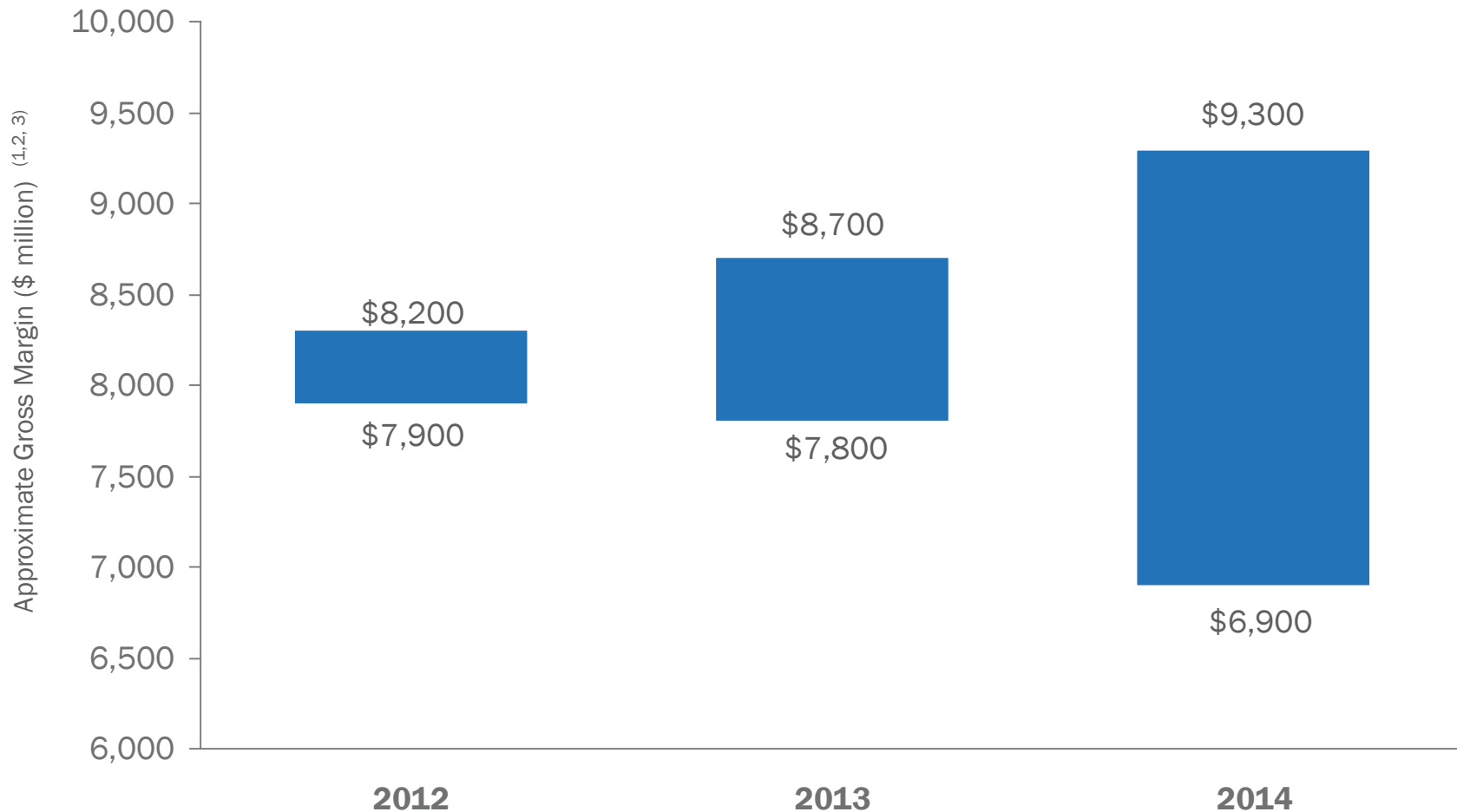
(1) Stub period calculated by excluding Jan 2012 thru mid-March 2012 for Constellation only. (2) Excludes Maryland assets to be divested (3) Includes CENG Joint Venture. (4) Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted for capacity. 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) ^(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 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

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> <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.

Additional 2012 ExGen Modeling

P&L Item	2012 Stub ⁽¹⁾ Estimate	2012 Full-Year ⁽²⁾ Estimate
O&M ⁽³⁾	\$4,000M	\$4,250M
Taxes Other Than Income (TOTI)	\$300M	\$300M
Depreciation & Amortization ⁽⁴⁾	\$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

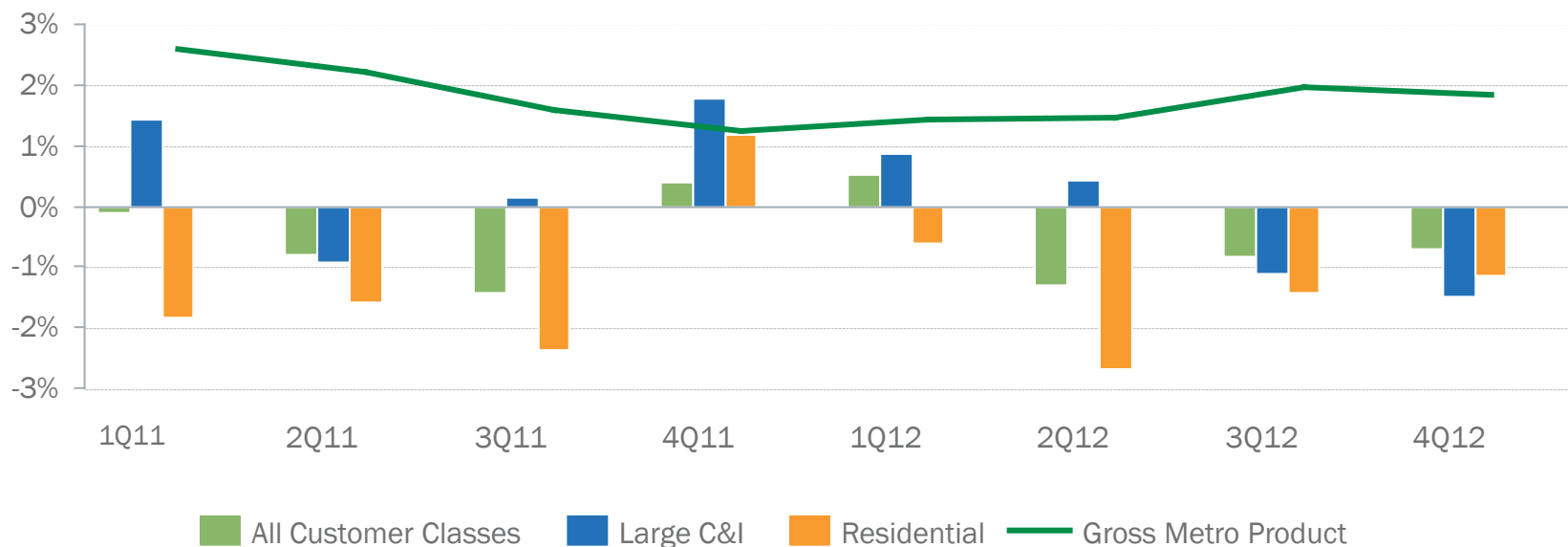
(2) Full-year estimates provided for modeling purposes.

(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 ⁽¹⁾	8.6%	8.2%
2012 annualized growth in gross domestic/metro product ⁽²⁾	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

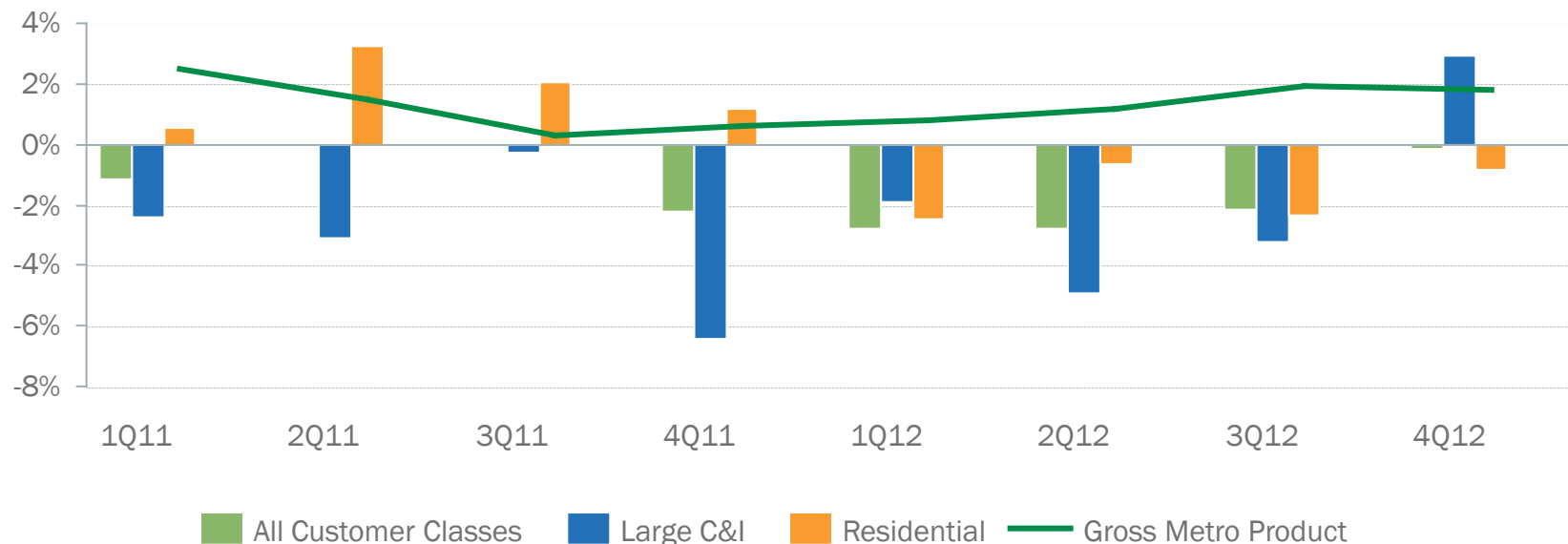
	2011	2012	2012E ⁽³⁾
Average Customer Growth	0.4%	0.3%	0.3%
Average Use-Per-Customer	<u>(1.7)%</u>	<u>(3.0)%</u>	<u>(1.7)%</u>
Total Residential	(1.3)%	(2.7)%	(1.4)%
Small C&I	(0.8)%	(1.8)%	(0.2)%
Large C&I	0.6%	0.4%	(0.4)%
All Customer Classes	(0.5)%	(1.3)%	(0.6)%

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 ⁽¹⁾	7.8%	8.2%
2012 annualized growth in gross domestic/metro product ⁽²⁾	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 ⁽³⁾
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 ⁽¹⁾	600	1,000	600	5,600	10,640
Outstanding Facility Draws	--	--	--	--	--
Outstanding Letters of Credit	(1)	(1)	(1)	(1,793)	(2,317)
Available Capacity Under Facilities⁽²⁾	599	999	599	3,807	8,323
Outstanding Commercial Paper	(35)	(256)	--	--	(462)
Available Capacity Less Outstanding Commercial Paper	564	743	599	3,807	7,861

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

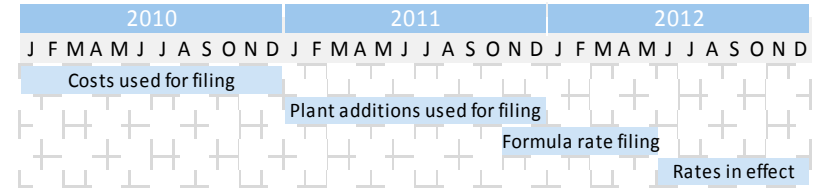
Summary of Filings

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)

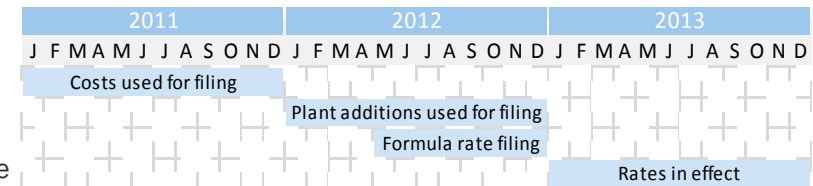
ICC Final Order (issued 5/30/12):

- \$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.



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)⁽¹⁾
- 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 intervenor testimony on 7/17/12
 - Staff proposes an additional \$35M reduction beyond ComEd's filing
- ICC order by year end; rates effective January 2013



(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



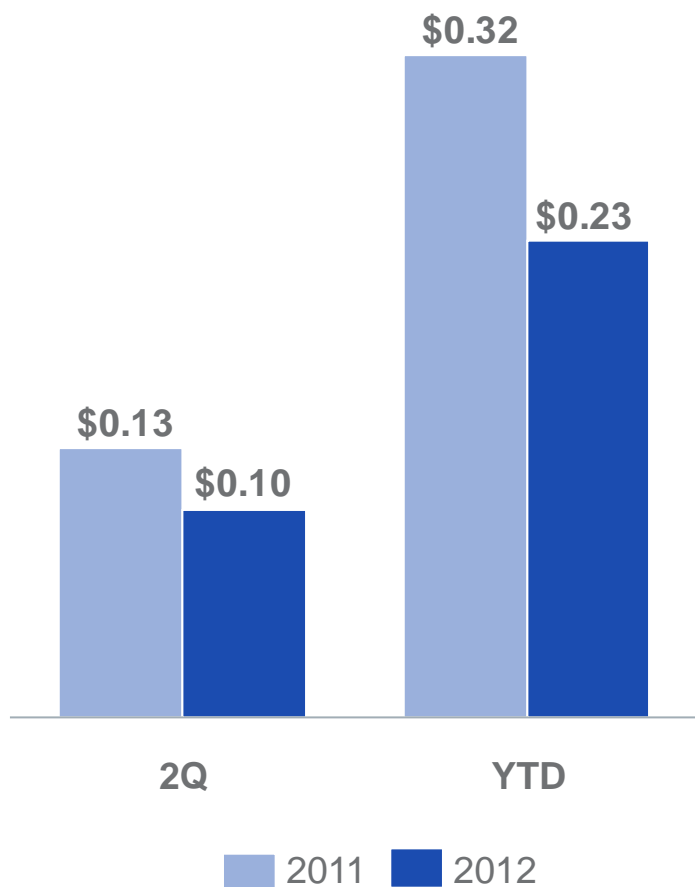
Key Drivers – 2012 vs. 2011 ⁽¹⁾

- 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 ⁽¹⁾

➤ 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>
2011 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.79	\$0.15	\$0.13	\$(0.01)	\$1.05
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)
2Q 2011 GAAP Earnings (Loss) Per Share	\$0.67	\$0.17	\$0.03	\$(0.03)	\$0.93

<u>Three Months Ended June 30, 2012</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>Other</u>	<u>Exelon</u>
2012 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$0.47	\$0.05	\$0.10	\$0.02	\$(0.02)	\$0.61
Mark-to-market impact of economic hedging activities	0.14	-	-	-	0.00	0.15
Unrealized losses related to 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
2Q 2012 GAAP Earnings (Loss) Per Share	\$0.19	\$0.05	\$0.09	\$0.01	\$(0.02)	\$0.33

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>
2011 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$1.69	\$0.26	\$0.32	\$(0.04)	\$2.22
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)
YTD 2011 GAAP Earnings (Loss) Per Share	\$1.41	\$0.28	\$0.26	\$(0.07)	\$1.94

<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>
2012 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$1.03	\$0.17	\$0.23	\$0.04	\$(0.03)	\$1.44
Mark-to-market impact of economic hedging activities	0.20	-	-	-	0.01	0.21
Unrealized gains related to 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)
YTD 2012 GAAP Earnings (Loss) Per Share	\$0.43	\$0.17	\$0.22	\$(0.07)	\$(0.13)	\$0.62

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
 - 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**