



Exelon and Constellation Energy: Merger and Company Update

**Edison Electric Institute Financial Conference
November 7-8, 2011**

Cautionary Statements Regarding Forward-Looking Information

Except for the historical information contained herein, certain of the matters discussed in this communication constitute “forward-looking statements” within the meaning of the Securities Act of 1933 and the Securities Exchange Act of 1934, both as amended by the Private Securities Litigation Reform Act of 1995. Words such as “may,” “will,” “anticipate,” “estimate,” “expect,” “project,” “intend,” “plan,” “believe,” “target,” “forecast,” and words and terms of similar substance used in connection with any discussion of future plans, actions, or events identify forward-looking statements. These forward-looking statements include, but are not limited to, statements regarding benefits of the proposed merger of Exelon Corporation (Exelon) and Constellation Energy Group, Inc. (Constellation), integration plans and expected synergies, the expected timing of completion of the transaction, anticipated future financial and operating performance and results, including estimates for growth. These statements are based on the current expectations of management of Exelon and Constellation, as applicable. There are a number of risks and uncertainties that could cause actual results to differ materially from the forward-looking statements included in this communication regarding the proposed merger. For example, (1) the companies may be unable to obtain shareholder approvals required for the merger; (2) the companies may be unable to obtain regulatory approvals required for the merger, or required regulatory approvals may delay the merger or result in the imposition of conditions that could have a material adverse effect on the combined company or cause the companies to abandon the merger; (3) conditions to the closing of the merger may not be satisfied; (4) an unsolicited offer of another company to acquire assets or capital stock of Exelon or Constellation could interfere with the merger; (5) problems may arise in successfully integrating the businesses of the companies, which may result in the combined company not operating as effectively and efficiently as expected; (6) the combined company may be unable to achieve cost-cutting synergies or it may take longer than expected to achieve those synergies; (7) the merger may involve unexpected costs, unexpected liabilities or unexpected delays, or the effects of purchase accounting may be different from the companies’ expectations; (8) the credit ratings of the combined company or its subsidiaries may be different from what the companies expect; (9) the businesses of the companies may suffer as a result of uncertainty surrounding the merger; (10) the companies may not realize the values expected to be obtained for properties expected or required to be divested; (11) the industry may be subject to future regulatory or legislative actions that could adversely affect the companies; and (12) the companies may be adversely affected by other economic, business, and/or competitive factors. Other unknown or unpredictable factors could also have material adverse effects on future results, performance or achievements of Exelon, Constellation or the combined company.

Cautionary Statements Regarding Forward-Looking Information (Continued)

Discussions of some of these other important factors and assumptions are contained in Exelon's and Constellation's respective filings with the Securities and Exchange Commission (SEC), and available at the SEC's website at www.sec.gov, including:

- (1) Exelon's 2010 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) Exelon's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2011 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 13;
- (3) Constellation's 2010 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; and
- (4) Constellation's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2011 in (a) Part II, Other Information, ITEM 1A. Risk Factors and ITEM 5. Other Information, (b) Part I, 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: Notes to Consolidated Financial Statements, Commitments and Contingencies.

These risks, as well as other risks associated with the proposed merger, are more fully discussed in the definitive joint proxy statement/prospectus included in the Registration Statement on Form S-4 that Exelon filed with the SEC and that the SEC declared effective on October 11, 2011 in connection with the proposed merger. In light of these risks, uncertainties, assumptions and factors, the forward-looking events discussed in this communication may not occur. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this communication. Neither Exelon nor Constellation undertake any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this communication.

Additional Information and Where to Find it

In connection with the proposed merger between Exelon and Constellation, Exelon filed with the SEC a Registration Statement on Form S-4 that included the definitive joint proxy statement/prospectus. The Registration Statement was declared effective by the SEC on October 11, 2011. Exelon and Constellation mailed the definitive joint proxy statement/prospectus to their respective security holders on or about October 12, 2011. **WE URGE INVESTORS AND SECURITY HOLDERS TO READ THE DEFINITIVE JOINT PROXY STATEMENT/PROSPECTUS AND ANY OTHER RELEVANT DOCUMENTS FILED WITH THE SEC, BECAUSE THEY CONTAIN IMPORTANT INFORMATION** about Exelon, Constellation and the proposed merger. Investors and security holders may obtain copies of all documents filed with the SEC free of charge at the SEC's website, www.sec.gov. In addition, a copy of the definitive joint proxy statement/prospectus may be obtained free of charge from Exelon Corporation, Investor Relations, 10 South Dearborn Street, P.O. Box 805398, Chicago, Illinois 60680-5398, or from Constellation Energy Group, Inc., Investor Relations, 100 Constellation Way, Suite 600C, Baltimore, MD 21202.

Compelling Merger Rationale

Strategic Benefits

- Creates the leading competitive energy provider in the U.S.
- 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

Competitive Portfolio

- Diversifies generation portfolio across regions
- Adds clean generation to the portfolio
- Enhances margins in the competitive portfolio

Financial Benefits

- Earnings and cash flow accretive
- Dividend uplift for Constellation shareholders
- Continued upside to power market recovery
- Strong balance sheet for combined company

Utility Benefits

- Maintains a regulated earnings profile with three large urban utilities
- Enables operational enhancements from sharing of best practices across utilities

Transaction creates incremental strategic and financial value aligned with both companies' existing goals

Merger Appeals to Key Stakeholders and Governments

Stakeholder	Commitments & Benefits
Customers	<ul style="list-style-type: none"> ▪ \$100 one-time credit for BGE residential customers ▪ Direct benefit from merger synergies at the utilities ▪ Opportunities for operational improvements through sharing of utilities' best practices ▪ \$15 million for various programs with direct benefits to BGE customers
Investors	<ul style="list-style-type: none"> ▪ Upfront premium of 18.5%⁽¹⁾ to CEG shareholders ▪ Dividend accretion of 103% post-close for CEG shareholders ▪ EPS accretion of >5% in 2013 ▪ Earnings upside to power market recovery ▪ Strong credit profile maintained for combined company
State of Maryland and City of Baltimore	<ul style="list-style-type: none"> ▪ Maintains a large employee presence and platform for growth in Maryland ▪ New LEED-certified headquarters for wholesale, retail and renewable energy development business in Baltimore ▪ BGE to maintain independent operations and remain headquartered in Baltimore ▪ 25 MWs of renewable energy development in MD ▪ \$4 million to support EmPower Maryland Energy Efficiency Act ▪ Charitable contributions maintained at current levels for at least 10 years after the merger closes

(1) Based on the 30-day average Exelon and Constellation closing stock prices as of April 26, 2011.

Enhanced Maryland Proposal

Intervenor Concerns	Key Exelon/Constellation Additional Commitments
Additional Customer Benefits	<ul style="list-style-type: none"> ▪ Added flexibility for Maryland PSC to determine use of \$15 million offered for programs directly benefiting BGE customers
Ring-Fencing	<ul style="list-style-type: none"> ▪ No corporate reorganization under certain defined circumstances relating to RF HoldCo, BGE or Exelon Energy Delivery Company without prior Commission approval ▪ Obtain a new non-consolidation opinion to ensure the effectiveness of BGE ring-fencing ▪ No requests for modification of BGE ring-fencing for 3 years
Financial	<ul style="list-style-type: none"> ▪ Regular reporting on credit ratings and metrics of BGE to Maryland PSC ▪ Specific commitments regarding the level of BGE capital and O&M expenditures in 2012 and 2013 ▪ Report comparative pre- and post-merger shared services costs to PSC
Corporate Governance	<ul style="list-style-type: none"> ▪ BGE's CEO will be a member of Exelon Management's Executive Committee ▪ Executive Committee will meet periodically in Baltimore
Service and Operation	<ul style="list-style-type: none"> ▪ Commitment to meet existing BGE supplier diversity requirements ▪ Provide assessment of BGE CAIDI (outage duration) performance within 12 months after the merger closes
Market Power	<ul style="list-style-type: none"> ▪ In addition to 2,648 MW of identified plant divestitures, comply with settlement terms with PJM Market Monitor restricting buyers of divested plants and imposing other behavioral commitments

Our additional commitments address a number of key stakeholder concerns

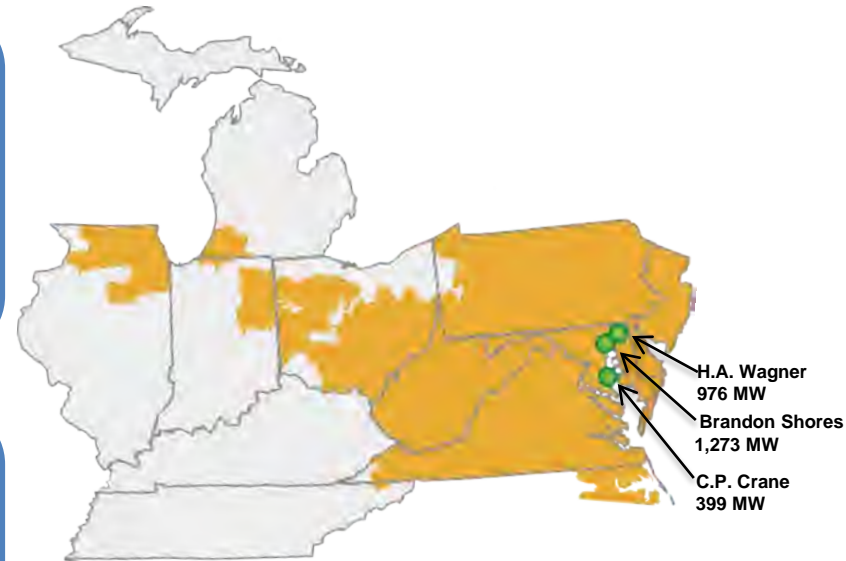
Strong Proposal to Address Market Power

Proactive divestiture proposal

- Analyzed market power considerations and proposed mitigation plan to address market concentration concerns
- Proposed comprehensive mitigation plan to address market concentration in PJM in initial application, including:
 - Physical sale of 3 baseload generation facilities totaling 2,648 MW
 - Additional sale of 500 MW via contracts to mitigate temporary market power issues

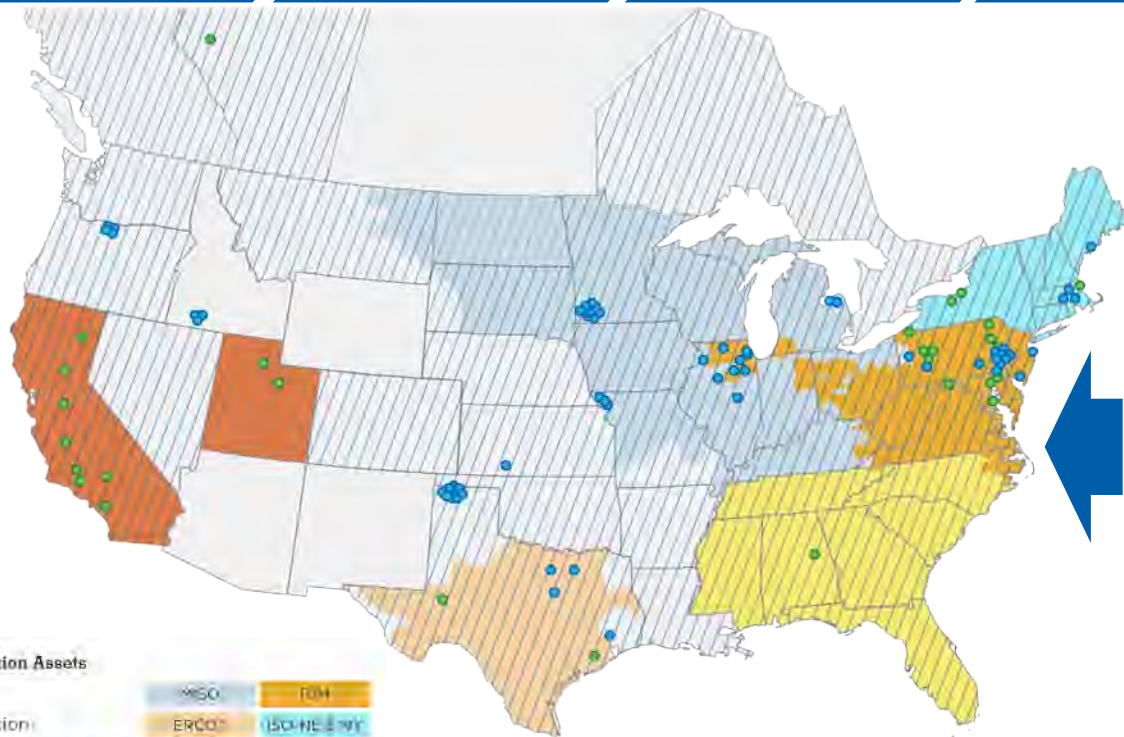
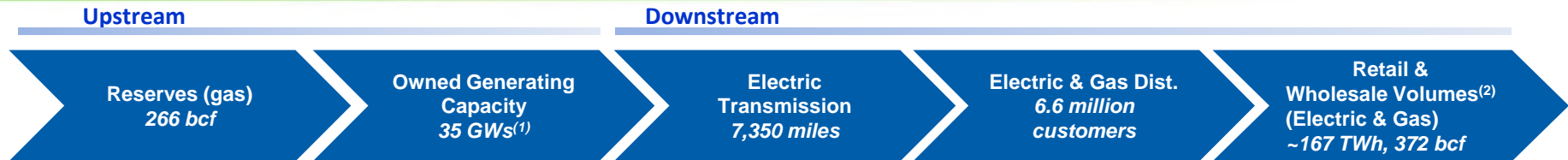
Settlement with PJM Independent Market Monitor (IMM)

- Filed with FERC and Maryland PSC on October 11, 2011
- No change to assets identified in original proposal
- Additional commitment not to sell plants to certain identified PJM generators
- Additional assurances on how we will bid units in PJM energy and capacity markets
- Future retirement of units will be conditioned on meeting specified requirements



The companies have offered a comprehensive, robust mitigation package

Scale, Scope and Flexibility Across the Value Chain



Notable Generation Acquired or Under Development in 2011

Exelon Additions

- 720 MW Wolf Hollow CCGT (TX)
- 230 MW Antelope Valley Solar Ranch One (CA)
- 230 MW Michigan Wind Projects (MI)

Constellation Additions

- 2,950 MW Boston Generating gas fleet
- 30.4 MW Sacramento Municipal Utility District Solar (CA)
- 16.1 MW Maryland Generating Clean Horizons Solar (MD)
- 7.8 MW Vineland Municipal Electric Utility Solar (NJ)
- 5.4 MW Toys "R" Us Solar (NJ)
- 5.2 MW Johnson Matthey, West Deptford Solar (NJ)
- 5.0 MW U.S. State Department Solar (NJ)

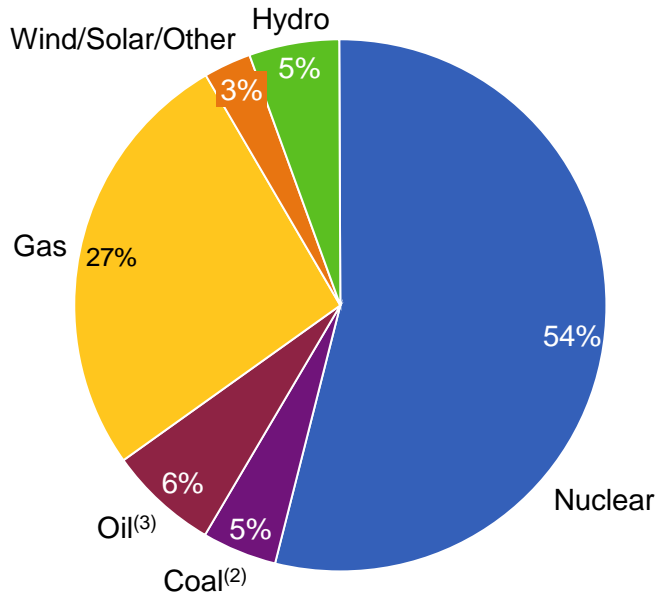
Transaction creates the largest – and growing – competitive energy company in the U.S.

Note: Data as of 9/30/11. Exelon solar addition MW based on alternating current (AC); Constellation solar additions (in MW) based on direct current (DC).

- (1) Generation capacity net of physical market mitigation assumed to be 2,648 MW consisting of Brandon Shores (1,273 MW), H.A. Wagner (976 MW) and C.P. Crane (399 MW).
- (2) Electric load includes all booked 2011E competitive retail and wholesale sales, including index products. Exelon load does not include the ComEd swap (~26 TWh). Gas load includes all booked and forecasted 2011E competitive retail sales as of 9/30/11.

Well Positioned for Evolving Regulatory Requirements

Combined Company Portfolio



Total Generation Capacity⁽¹⁾: 35,327 MW

- Cleanest large 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⁽⁴⁾ (Exelon and Constellation ownership share ~31%)
- Low-cost generation capacity provides unparalleled leverage to rising commodity prices
- Incremental 500 MW of coal and oil capacity to be retired by middle of next year

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

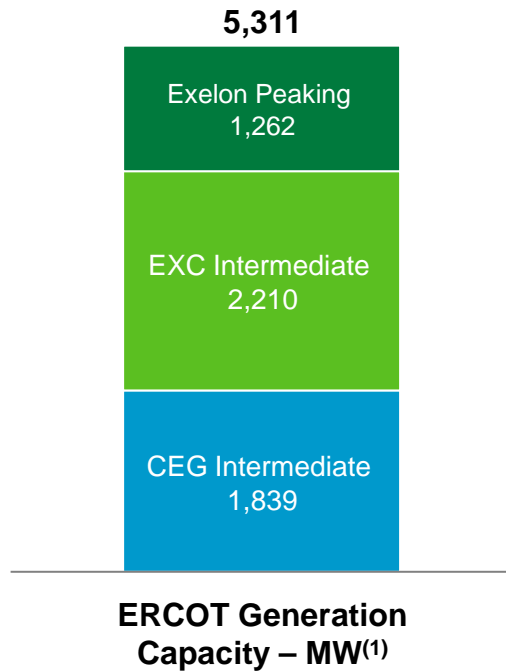
(1) Total owned generation capacity as of 9/30/2011 for Exelon and Constellation, net of physical market mitigation assumed to be 2,648 MW.

(2) Coal capacity shown above includes Eddystone 2 (309 MW) to be retired on 6/1/2012.

(3) Oil capacity shown above includes Cromby 2 (201 MW) to be retired on 12/31/2011.

(4) Pending approval of owner group.

Texas Generation Portfolio Is Well Suited to Serve Load



- **Premium Location** – A sizeable generation position close to large load pockets in Dallas and Houston
- **Strong Asset Mix** – Intermediate and peaking generation assets are effectively call options at various heat rates that benefit from price volatility
- **Hedging Flexibility** – Leverage strong asset base and utilize market-based hedging instruments to effectively manage load-following obligations

The combined generation portfolio will enhance the hedging capability for managing load positions in Texas

(1) Generation and capacity for Exelon and Constellation includes owned and contracted units, less any PPAs or tolls sold, as of 09/30/2011. Exelon wind assets in Texas (open or hedged) are not included in the capacity shown above. Constellation capacity includes 517 MWs under a contract that expires in December 2011.

Wholesale and Retail Businesses

Hedging Program Characteristics

Manage Risk
on a Ratable
Basis

Incorporate
Fundamental
Market Views

Utilize Multiple
Markets &
Products

Protect
Investment-
Grade Credit
Rating



- Increase the amount of generation hedged over time, leaving some open generation length
- Exhibit flexibility in timing and type of sales executed based on market expectations
- Select products and markets that optimize the value of the generation portfolio
- Integrate hedging policy with financial planning process to protect investment-grade credit rating

Growing the Portfolio

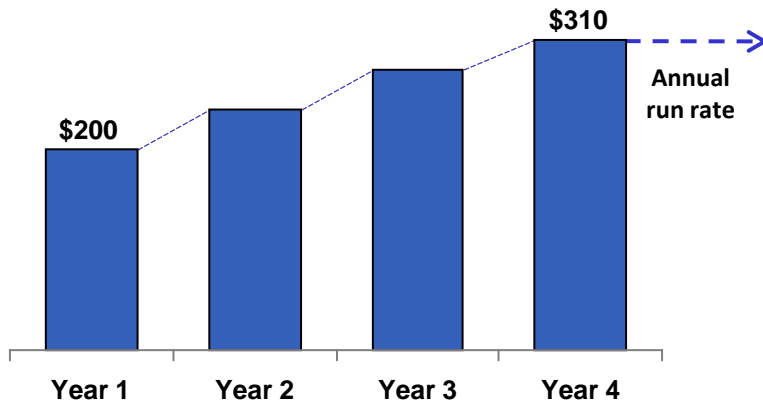
- Grow our generation to load strategy in multiple regions of the country by identifying attractive investments and markets
- Expand product offerings to customers in regions we serve

We will continue to use a well-defined hedging strategy to carefully balance risk management and value creation

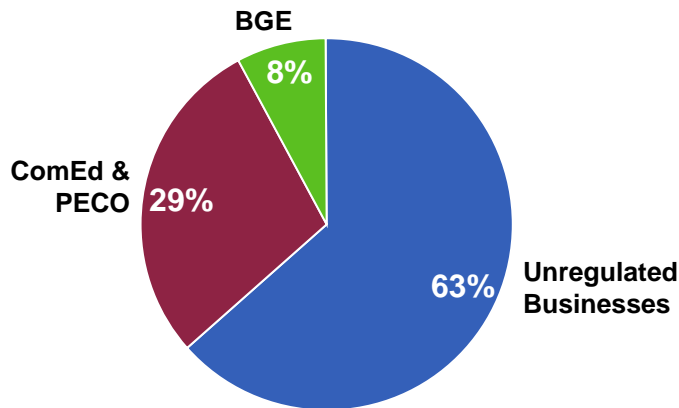
Transaction Maintains Solid Financial Position

Achievable Synergies

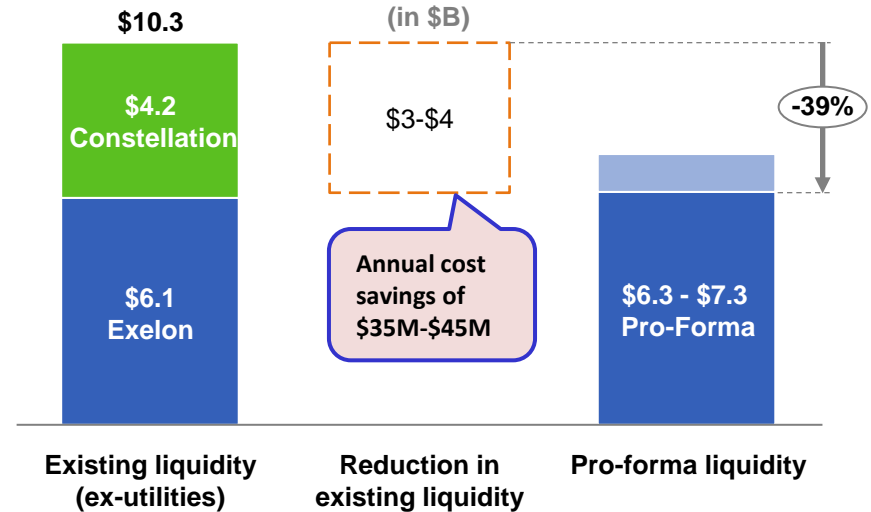
Annual O&M Expense Savings⁽¹⁾
(in \$MM)



5-Year Total Synergies Allocation⁽²⁾



Lower Liquidity Requirements



Maintaining Strong Investment Grade Ratings⁽³⁾

	Moody's Credit Ratings	S&P Credit Ratings	Fitch Credit Ratings
Exelon	Baa1	BBB-	BBB+
ComEd	Baa1	A-	BBB+
PECO	A1	A-	A
Generation	A3	BBB	BBB+
Constellation	Baa3	BBB-	BBB-
BGE	Baa2	BBB+	BBB+

(1) Before total costs to achieve of ~\$650M primarily attributable to employee-related costs and transaction costs.

(2) Source: DeGregorio testimony filed with Maryland PSC on May 25, 2011.

(3) Ratings as of November 1, 2011. Represents senior unsecured ratings of Exelon, Generation, Constellation and BGE and senior secured ratings for ComEd and PECO. S&P and Fitch affirmed all Exelon ratings upon announcement of merger. Moody's affirmed the ratings of ComEd and PECO and placed the ratings of Exelon and Generation on review for downgrade. S&P and Moody's placed Constellation on credit watch positive and affirmed BGE ratings. Fitch affirmed Constellation and BGE ratings upon announcement.

Phased Approach to Designing the Future



Success is defined by:

- Closing the transaction in early 2012
- Maintaining consistent and reliable operations
- Capturing value and meeting synergy targets
- Meeting commitments to stakeholders, regulators and governments
- Acting as one to build an integrated enterprise that is positioned for continued growth

Our past experience with successful integration and our phased approach to integrating Exelon and Constellation will enable the realization of merger benefits



Exelon & Constellation Energy Appendix

Merger Approvals Process on Schedule (as of 11/1/11)

Stakeholder	Status of Key Milestones	Approved
Texas PUC (Case No. 39413)	<ul style="list-style-type: none"> Filed for approval with the Public Utility Commission of Texas on May 17, 2011 Approval received on August 3, 2011 	●
Securities and Exchange Commission (SEC) (File No. 333-175162)	<ul style="list-style-type: none"> Joint proxy statement declared effective on October 11, 2011 	●
Shareholder Approval	<ul style="list-style-type: none"> Proxies mailed to shareholders of record at October 7, 2011 Shareholder meetings set for November 17, 2011 	
New York PSC (Case No. 11-E-0245)	<ul style="list-style-type: none"> Filed with the New York Public Service Commission on May 17, 2011 seeking a declaratory order confirming that a Commission review is not required Decision expected in Q4 2011 	
Department of Justice (DOJ)	<ul style="list-style-type: none"> Submitted Hart-Scott-Rodino filing on May 31, 2011 for review under U.S. antitrust laws and certified compliance with second request Clearance expected by January 2012 	
Federal Energy Regulatory Commission (FERC) (Docket No. EC 11-83)	<ul style="list-style-type: none"> Filed merger approval application and related filings on May 20, 2011, which assesses market power-related issues Settlement agreement filed with PJM Market Monitor on October 11, 2011 Order expected by November 16, 2011 (end of statutory period) 	
Nuclear Regulatory Commission (Docket Nos. 50-317, 50-318, 50-220, 50-410, 50-244, 72-8, 72-67)	<ul style="list-style-type: none"> Filed for indirect transfer of Constellation Energy licenses on May 12, 2011 Order expected by January 2012 	
Maryland PSC (Case No. 9271)	<ul style="list-style-type: none"> Filed for approval with the Maryland Public Service Commission on May 25, 2011 Evidentiary hearings begin October 31, 2011 Order expected by January 5, 2012 	

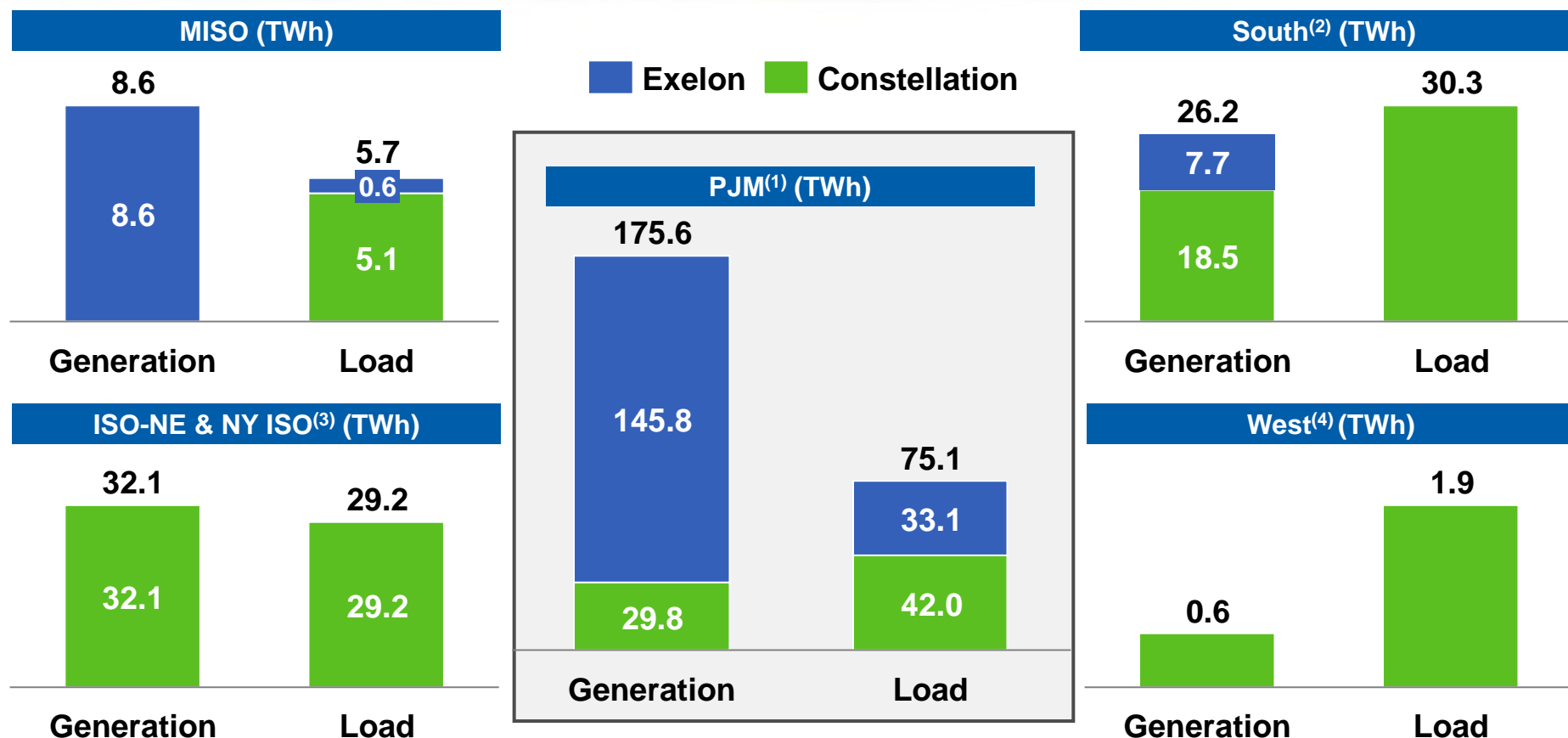
Note: The Department of Public Utilities in Massachusetts concluded on September 26, 2011 that it does not have jurisdiction over the merger.

Maryland PSC Review Schedule (Case No. 9271)

Significant Events	Date of Event
■ Filing of Application	May 25, 2011
■ Intervention Deadline	June 24, 2011
■ Prehearing Conference	June 28, 2011
■ Filing of Staff, Office of People Counsel and Intervenor Testimony	September 16, 2011*
■ Filing of Rebuttal Testimony	October 12, 2011*
■ Filing of Surrebuttal Testimony	October 26, 2011
■ Status Conference	October 28, 2011
■ Evidentiary Hearings	October 31, 2011 - November 18, 2011
■ Public Comment Hearings	November 29, December 1 & December 5, 2011
■ Filing of Initial Briefs	December 5, 2011
■ Filing of Reply Briefs	December 19, 2011
■ Decision Deadline	January 5, 2012

* Initial intervenor testimony with respect to market power was due on September 23rd for all parties except for the Independent Market Monitor and rebuttal testimony with respect to market power was due on October 17th.

Portfolio Matches Generation with Load in Key Competitive Markets



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

Note: Data for Exelon and Constellation represents available expected generation (owned and contracted) and booked electric sales for 2011 as of 9/30/11. Expected generation is adjusted for assets that have long term PPAs sold by Exelon or Constellation, including but not limited to wind and South assets. Exelon load doesn't include the ComEd swap (~26 TWh). Index load, which is a pass through load product with no price or volumetric risk to the seller, is not included in the load estimate.

(1) Constellation generation includes output from Brandon Shores, C.P. Crane and H.A. Wagner (total generation ~8.5 TWh).

(2) Represents load and generation in ERCOT, SERC and SPP.

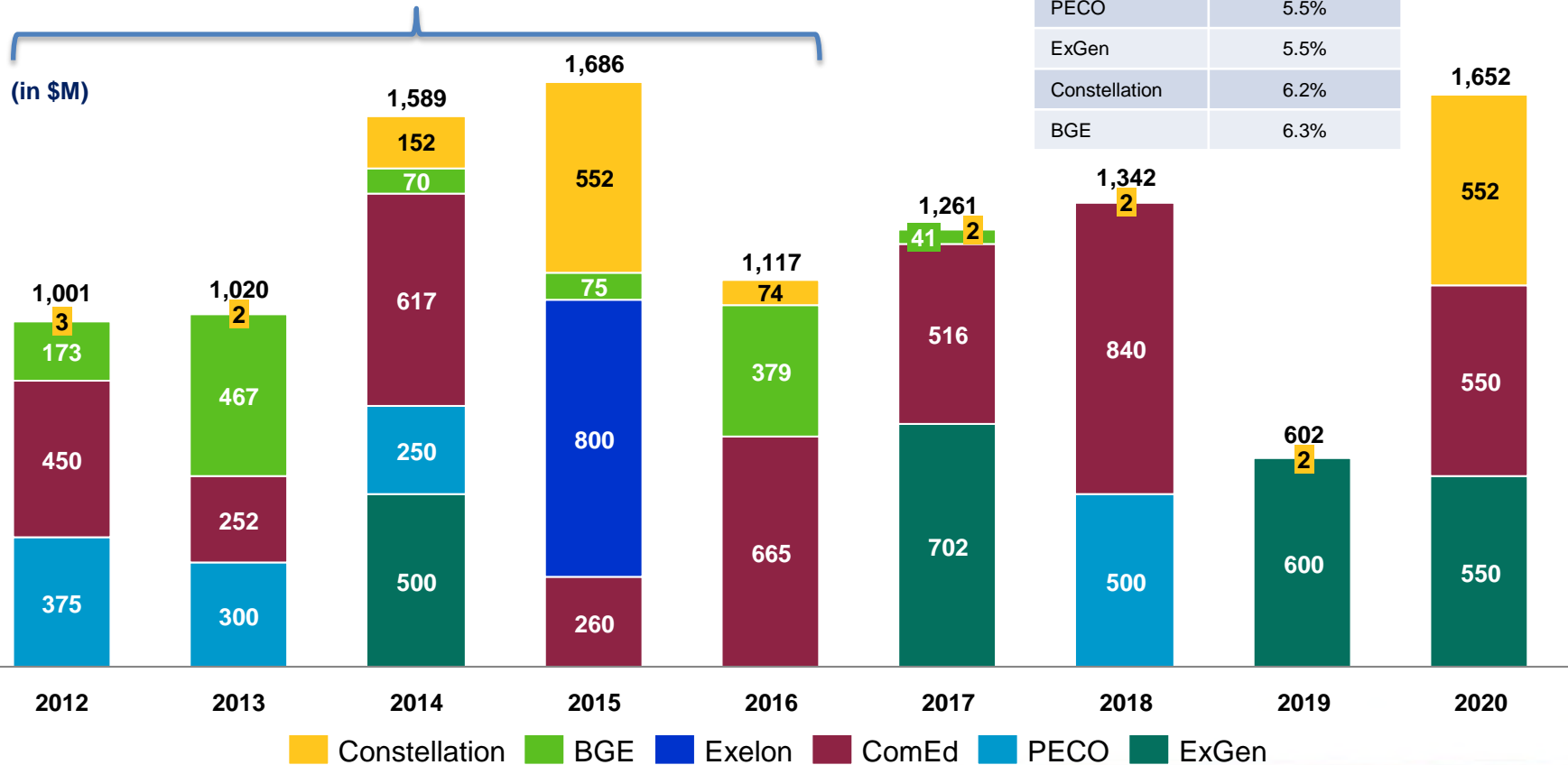
(3) Constellation load includes ~0.7 TWh of load served in Ontario.

(4) Constellation generation includes ~0.4 TWh of generation in Alberta.

Manageable Debt Maturities

Debt Maturity Profile (2012-2020)⁽¹⁾

~70% of 2012 – 2016 debt maturities consist of regulated utility debt



Weighted Average Cost of Debt⁽²⁾

Exelon	5.2%
ComEd	5.4%
PECO	5.5%
ExGen	5.5%
Constellation	6.2%
BGE	6.3%

(1) Debt maturity schedule and weighted average cost of debt as of 9/30/11. Amounts do not include fair value swaps at Constellation. BGE debt balances include annual transition bond payments from 2012 – 2017.

(2) Weighted average cost of debt excludes any benefits for interest rate swaps. Utilities' weighted average cost of debt includes debt amortization costs.

Exelon Dividend

- Exelon's Board of Directors approved a contingent stub dividend for Exelon shareholders of \$0.00571/share per day for Q1 2012 in anticipation of the merger close (\$0.525/share for the quarter)
- Stub dividend declaration ensures that Exelon shareholders continue to receive all dividends at the current \$2.10 per share annualized rate
- Pre- and post-close stub dividends must be declared separately to account for Constellation shareholders becoming Exelon shareholders at merger close

Assuming a February 1, 2012 close **for illustrative purposes only:**

Record Date	Payment Date		Per Share Amount	
11/15/2011	12/09/2011	Regular Dividend	\$0.525	
1/31/2012	3/1/2012	Pre-close Stub Dividend ⁽¹⁾	\$0.440	} \$0.525
2/15/2012	3/09/2012	Post-close Stub Dividend ⁽¹⁾	\$0.085	
5/15/2012	6/09/2012	Regular Dividend ⁽²⁾	\$0.525	

Current Exelon shareholders will continue to receive a total dividend of \$0.525 per quarter

(1) Assuming a 2/1/2012 merger close; for Exelon shareholders, Q1 2012 dividend will be based on a per diem rate of \$0.00571 (\$0.525 divided by 92 days).

(2) Future dividend, following the stub dividend, is subject to approval by the Board of Directors.

Constellation Dividend

- Constellation Energy's Board of Directors approved a contingent stub dividend for Constellation shareholders of \$0.00264/share per day for Q1 2012 in anticipation of merger close
- Stub dividend declaration ensures that Constellation shareholders continue to receive their existing quarterly dividend rate prior to the merger, and benefit from the Exelon annualized dividend rate (\$2.10 per share) beginning on the day the merger closes
- Pre- and post-close stub dividends must be declared separately to account for Constellation shareholders becoming Exelon shareholders at merger close

Assuming a February 1, 2012 close **for illustrative purposes only** :

Record Date	Payment Date		Per Share Amount
12/12/2011	1/03/2012	Regular CEG Dividend	\$0.24
1/31/2012	3/1/2012	Pre-close CEG Stub Dividend ⁽¹⁾	\$0.132
2/15/2012	3/09/2012	Post-close EXC Stub Dividend ⁽¹⁾	\$0.085
5/15/2012	6/09/2012	Regular EXC Dividend ⁽²⁾	\$0.525

Constellation shareholders will receive the Exelon dividend rate upon merger close

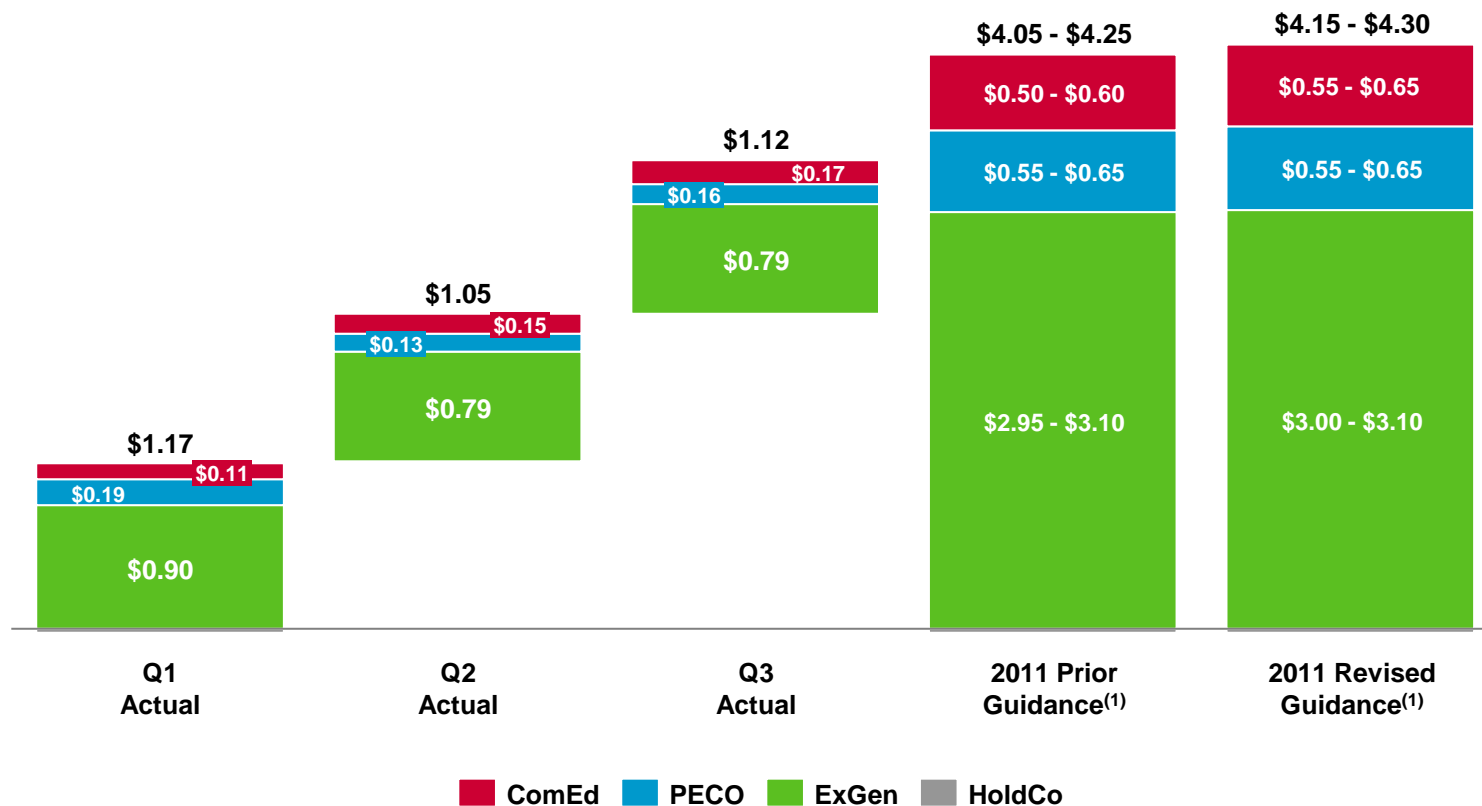
(1) Assuming a 2/1/2012 merger close, Q1 2012 dividend will be based on a per diem rate of \$0.00264 (\$0.24 divided by 91 days). Post-close Exelon Q1 2012 stub dividend will be based on a per diem rate of \$0.00571.

(2) Assuming a 2/1/2012 merger close, Constellation shareholders will start receiving the full quarterly Exelon dividend of \$0.525 per share in Q2 2012. Future dividend, following the stub dividend, is subject to approval by the Board of Directors.



Financial and Operating Data

2011 Operating Earnings Guidance



**2011 operating earnings guidance is \$4.15-\$4.30/share⁽²⁾;
2012 guidance for combined company to be provided after merger close**

(1) Earnings guidance for OpCos may not add up to consolidated EPS guidance.

(2) Refer to slides 29 and 30 for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS.

Exelon's Commitment to Growth



Organic Growth

Nuclear Fleet Expansion via Upgrades:

Industry leading, proven and value driven program to add 1,175 – 1,300 MW to the nation's largest nuclear fleet

RiteLine Transmission Project:

First major foray into development of backbone transmission projects with \$1.1 billion investment

Competitive Markets

Wolf Hollow Acquisition:

Diversify generation technology and expand footprint in Texas via acquisition of 720 MW combined cycle plant

Merchant Transmission Projects:

Investments to improve transmission infrastructure in western PJM and MISO to reduce congestion

Renewables

Wind Development:

Exelon Wind to expand its portfolio to at least 965 MW of capacity by year end 2012 with operations in eight states

Solar Investment:

Acquisition of Antelope Valley Solar Ranch One (230 MW), one of the largest solar PV projects in the world

Utility Infrastructure

PECO Smart Grid:

Investment of \$650 million with rate recovery to build out advanced meter infrastructure network

ComEd System Modernization:

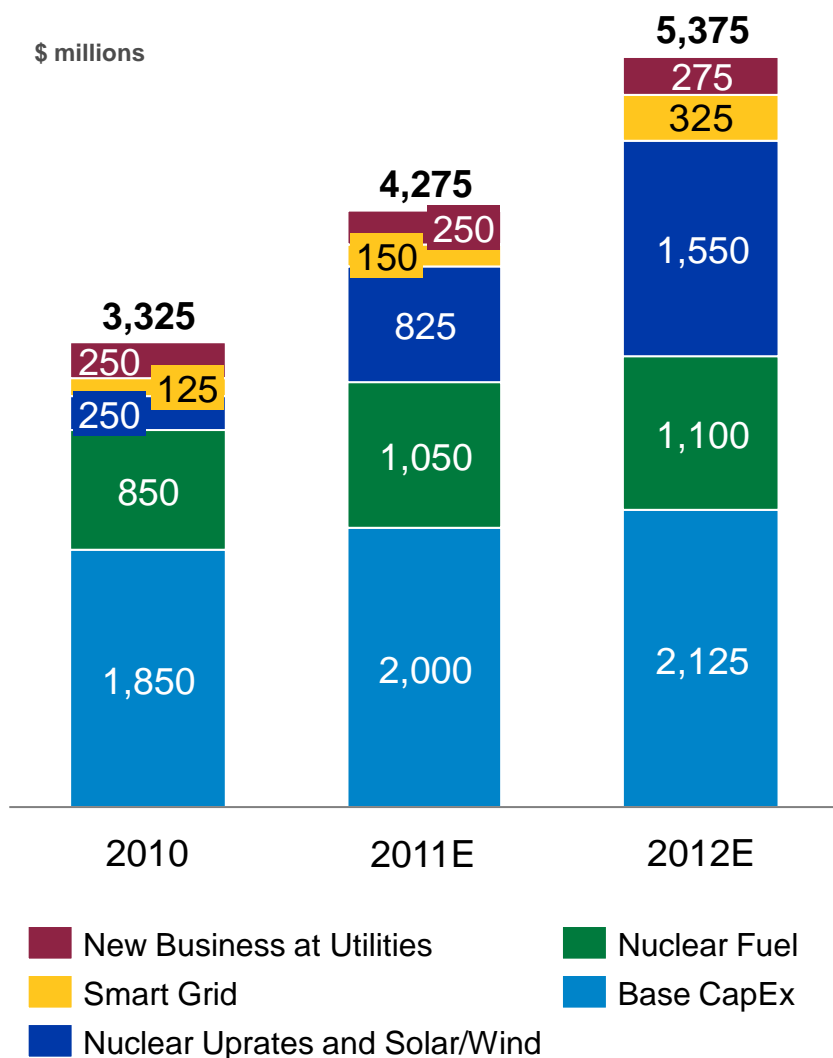
\$2.6B of incremental investment over 10 years and formula rates for distribution

Exelon continues to diversify and grow on a standalone basis with investments that are earnings and cash flow accretive

Exelon Capital Expenditures Expectations



\$ millions



Exelon Generation

	2010	2011E	2012E
Base CapEx ⁽¹⁾	775	850	825
Nuclear Fuel ⁽²⁾	850	1,050	1,100
Nuclear Upgrades	250	375	450
Solar / Wind	-	450	1,100
Total ExGen	1,875	2,725	3,475

ComEd

	2010	2011E	2012E
Base CapEx ⁽³⁾	650	750	975
Smart Grid/Meter ⁽³⁾	100	75	250
New Business ⁽⁴⁾	200	200	225
Total ComEd	950	1,025	1,450

PECO

	2010	2011E	2012E
Base CapEx	425	350	300
Smart Grid/Meter	25	75	75
New Business	50	50	50
Total PECO	500	475	425

	2010	2011E	2012E
Corporate	-	50	25

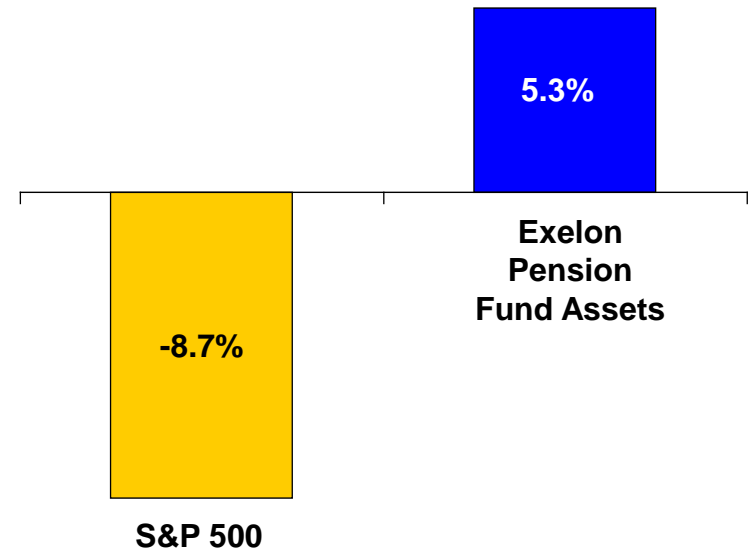
- (1) Excludes potential capex associated with NRC Post-Fukushima requirements which have not yet been finalized.
 (2) Nuclear fuel shown at ownership, including Salem.
 (3) Includes capex associated with SB 1652 in 2012.
 (4) Includes transmission growth projects.

Pension Funds Performance



- Investment strategy achieved positive 2011 YTD returns in a very challenging market environment due to effectiveness of asset allocations and hedging strategy:
 - Diversified asset allocation
 - Decreased equity investments and increased investment in fixed income securities and alternative investments
 - Liability hedge
 - The liability hedge has offset more than 50% of the pension liability increase caused by lower interest rates
- Pension plans are 83% funded as of September 30, 2011
- Anticipate no substantial changes to contribution plan

2011 YTD Returns at 9/30/2011



Exelon's pension investment strategy has effectively dampened the volatility of plan assets and plan funded status

2012 Pension and OPEB Sensitivities



- Tables below provide sensitivities for Exelon's 2012 pension and OPEB expense and contributions⁽¹⁾ under various discount rate and S&P 500 asset return scenarios
 - Pension and OPEB asset returns are driven by overall market performance (S&P 500 is used as a proxy) as well as discount rates

2012 Pension Sensitivity ⁽²⁾						
Discount Rate on 12/31/11	S&P 500 Returns in Q4 2011 ⁽³⁾					
	5%		0%		-5%	
	Pre-Tax Expense (in M)	Contribution (in M)	Pre-Tax Expense (in M)	Contribution (in M)	Pre-Tax Expense (in M)	Contribution (in M)
4.85% ⁽⁴⁾	\$290	\$140	\$300	\$140	\$305	\$140
+50 bps (5.35%)	\$260	\$140	\$265	\$140	\$270	\$140
-50 bps (4.35%)	\$330	\$130	\$335	\$130	\$340	\$135

2012 OPEB Sensitivity ⁽²⁾						
Discount Rate on 12/31/11	S&P 500 Returns in Q4 2011 ⁽³⁾					
	5%		0%		-5%	
	Pre-Tax Expense (in M)	Contribution (in M)	Pre-Tax Expense (in M)	Contribution (in M)	Pre-Tax Expense (in M)	Contribution (in M)
4.92% ⁽⁴⁾	\$260	\$340	\$265	\$345	\$265	\$350
+50 bps (5.42%)	\$235	\$310	\$240	\$315	\$240	\$320
-50 bps (4.42%)	\$290	\$375	\$290	\$380	\$295	\$385

Note: Tables above for illustrative purposes and not intended to represent a forecast of future outcomes.

(1) Contributions shown in the table above are based on Exelon's current contribution policy.

(2) Pension and OPEB expenses assume 25% capitalization rate.

(3) Final 2011 asset return for pension and OPEB will depend in part on overall equity market returns in Q4 2011 as proxied by the S&P 500. As of 9/30/11, YTD S&P return was -8.7%.

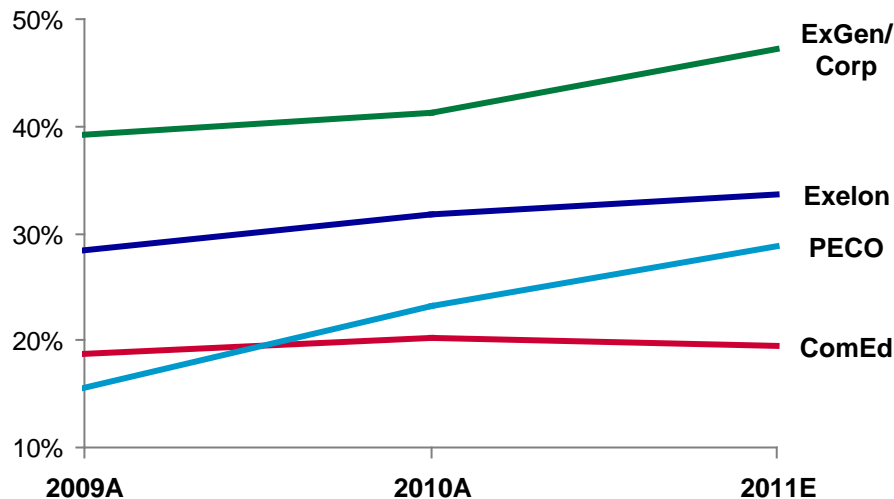
(4) Projected 12/31/11 discount rate as of 9/30/11.

Exelon Credit Metric Outlook



- Credit metrics continue to be very strong at each operating company
- Managing 5-year financial plan to ensure each operating company can maintain strong investment grade credit ratings under a variety of economic scenarios
- Expect to be at or above target ranges through 2013, while funding growth projects and meeting future obligations including dividend, pension and uprates

FFO/Debt Forecast and Target Range



	FFO / Debt Target Range
ComEd:	15-18%
PECO:	15-18%
Generation:	30-35% ⁽¹⁾

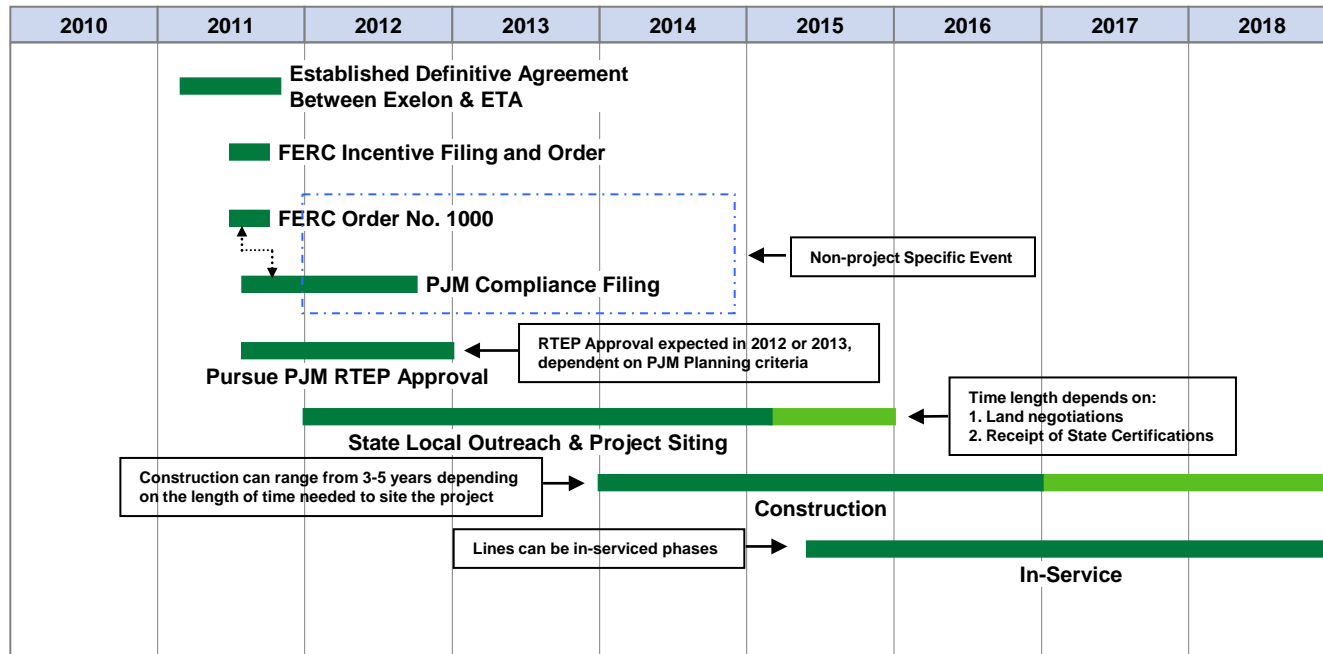
Through 2013, Exelon expects to maintain credit metrics at or above targets

(1) FFO/Debt Target Range reflects Generation FFO/Debt in addition to the debt obligations of Exelon Corp. Range represents FFO/Debt to maintain current ratings at current business risk.

RITE Line Transmission Project



- 420 miles of 765kV transmission stretches from Northern Illinois to Ohio border
- ComEd/Exelon investment ~\$1.1 billion – no significant investment expected in 2012
- FERC accepted Formula Rate and granted incentives for the project, with a 11.43% total ROE
 - 100% CWIP and 100% cost recovery if the project is abandoned through no fault of developers
 - 9.93% base ROE with 150 basis points of incentives
- Pursuing PJM RTEP Approval, expect confirmation in 2012 or 2013
- Project ensures reliability, enables states to meet RPS standards, and reduces congestion



YTD GAAP EPS Reconciliation



<u>Nine Months Ended September 30, 2010</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>Other</u>	<u>Exelon</u>
2010 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$2.10	\$0.55	\$0.51	\$(0.06)	\$3.10
2007 Illinois electric rate settlement	(0.01)	-	-	-	(0.01)
Mark-to-market impact of economic hedging activities	0.25	-	-	-	0.25
Unrealized gains related to nuclear decommissioning trust funds	0.04	-	-	-	0.04
Non-cash charge resulting from health care legislation	(0.04)	(0.02)	(0.02)	(0.02)	(0.10)
Non-cash remeasurement of income tax uncertainties	0.10	(0.16)	(0.03)	(0.01)	(0.10)
Retirement of fossil generating units	(0.05)	-	-	-	(0.05)
Emission allowances impairment	(0.05)	-	-	-	(0.05)
YTD 2010 GAAP Earnings (Loss) Per Share	\$2.34	\$0.37	\$0.46	\$(0.09)	\$3.08

<u>Nine Months Ended September 30, 2011</u>	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>Other</u>	<u>Exelon</u>
2011 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$2.47	\$0.43	\$0.47	\$(0.03)	\$3.34
Mark-to-market impact of economic hedging activities	(0.34)	-	-	-	(0.34)
Unrealized losses related to nuclear decommissioning trust funds	(0.07)	-	-	-	(0.07)
Retirement of fossil generating units	(0.04)	-	-	-	(0.04)
Asset retirement obligation	(0.03)	-	0.00	-	(0.02)
Constellation acquisition costs	(0.00)	(0.00)	(0.00)	(0.03)	(0.04)
AVSR 1 acquisition costs	(0.01)	-	-	-	(0.01)
Non-cash charge resulting from Illinois tax rate change legislation	(0.03)	(0.01)	-	(0.00)	(0.04)
Wolf Hollow acquisition	0.03	-	-	-	0.03
Recovery of costs pursuant to distribution rate case order	-	0.03	-	-	0.03
YTD 2011 GAAP Earnings (Loss) Per Share	\$1.99	\$0.44	\$0.47	\$(0.07)	\$2.84

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 2011 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
 - Significant impairments of assets, including goodwill
 - Changes in decommissioning obligation and asset retirement obligation estimates
 - Non-cash charge to remeasure deferred taxes at higher Illinois corporate tax rates
 - Financial impacts associated with the planned retirement of fossil generating units
 - One-time benefits reflecting ComEd's 2011 distribution rate case order for the recovery of previously incurred costs related to the 2009 restructuring plan and for the passage of Federal health care legislation in 2010
 - Certain costs associated with Exelon's acquisition of a wind portfolio (now known as Exelon Wind) and AVSR 1, and Exelon's proposed merger with Constellation
 - Non-cash gain on purchase in connection with the acquisition of Wolf Hollow, net of acquisition costs
 - Non-cash charge remeasurement of income tax uncertainties
 - Non-cash charge resulting from passage of Federal health care legislation
 - Costs associated with the 2007 electric rate settlement agreement
 - Impairment of certain emission allowances
 - Other unusual items
 - Significant changes to GAAP
- **Operating earnings guidance assumes normal weather for remainder of the year**

Exelon Consolidated Metric Calculations and Ratios

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2010A Credit Metrics

FFO / Debt Coverage =

$$\frac{\text{FFO (a)}}{\text{Adjusted Debt (b)}} = 32\%$$

FFO Interest Coverage =

$$\frac{\text{FFO (a) + Adjusted Interest (c)}}{\text{Adjusted Interest (c)}} = 7.2x$$

Adjusted Capitalization (e) =

Adjusted Debt (b) + Adjusted Equity (d) = 32,606

Rating Agency Debt Ratio =

$$\frac{\text{Adjusted Debt (b)}}{\text{Adjusted Capitalization (e)}} = 58\%$$

Exelon 2010 YE Adjustments

\$ in millions

FFO Calculation

	2010 YE	Source - 2010 Form 10-K (.pdf version)
Net Cash Flows provided by Operating Activities	5,244	Pg 159 - Stmt. of Cash Flow s
+/- Change in Working Capital	644	Pg 159 - Stmt. of Cash Flow s ⁽¹⁾
- PECO Transition Bond Principal Paydown	(392)	Pg 174 - Stmt. of Cash Flow s ⁽²⁾
+ PPA Depreciation Adjustment	207	Pg 295 - Commitments and Contingencies ⁽³⁾
+/- Pension/OPEB Contribution Normalization	448	Pg 268-269 - Post-retirement Benefits ⁽⁴⁾
+ Operating Lease Depreciation Adjustment	35	Pg 299 - Commitments and Contingencies ⁽⁵⁾
+/- Decommissioning activity	(143)	Pg 159- Stmt. of Cash Flow s
+/- Other Minor FFO Adjustments ⁽⁶⁾	(54)	
= FFO (a)	5,989	

Debt Calculation

Long-term Debt (incl. Current Maturities and A/R agreement)	12,828	Pg 161 - Balance Sheet
Short-term debt (incl. Notes Payable / Commercial Paper)	-	Pg 161 - Balance Sheet
- PECO Transition Bond Principal Paydown	-	N/A - no debt outstanding at year-end
+ PPA Imputed Debt	1,680	Pg 295 - Commitments and Contingencies ⁽⁷⁾
+ Pension/OPEB Imputed Debt	3,825	Pg 268 - Post-retirement benefits ⁽⁸⁾
+ Operating Lease Imputed Debt	428	Pg 299 - Commitments and Contingencies ⁽⁹⁾
+ Asset Retirement Obligation	-	Pg 261-267 - Asset Retirement Obligations ⁽¹⁰⁾
+/- Other Minor Debt Equivalents ⁽¹¹⁾	84	
= Adjusted Debt (b)	18,845	

Interest Calculation

Net Interest Expense	817	Pg 158 - Statement of Operations
- PECO Transition Bond Interest Expense	(22)	Pg 182 - Significant Accounting Policies
+ Interest on Present Value (PV) of Operating Leases	29	Pg 299 - Commitments and Contingencies ⁽¹²⁾
+ Interest on PV of Purchased Power Agreements (PPAs)	99	Pg 295 - Commitments and Contingencies ⁽¹³⁾
+/- Other Minor Interest Adjustments ⁽¹⁴⁾	37	
= Adjusted Interest (c)	960	

Equity Calculation

Total Equity	13,563	Pg 161 - Balance Sheet
+ Preferred Securities of Subsidiaries	87	Pg 161 - Balance Sheet
+/- Other Minor Equity Equivalents ⁽¹⁵⁾	111	
= Adjusted Equity (d)	13,761	

(1) Includes changes in A/R, Inventories, A/P and other accrued expenses, option premiums, counterparty collateral and income taxes. Impact to FFO is opposite of impact to cash flow

(2) Reflects retirement of variable interest entity + change in restricted cash

(3) Reflects net capacity payment – interest on PV of PPAs (using weighted average cost of debt)

(4) Reflects employer contributions – (service costs + interest costs + expected return on assets), net of taxes at 35%

(5) Reflects operating lease payments – interest on PV of future operating lease payments (using weighted average cost of debt)

(6) Includes AFUDC / capitalized interest

(7) Reflects PV of net capacity purchases (using weighted average cost of debt)

(8) Reflects unfunded status, net of taxes at 35%

(9) Reflects PV of minimum future operating lease payments (using weighted average cost of debt)

(10) Nuclear decommissioning trust fund balance > asset retirement obligation. No debt imputed

(11) Includes accrued interest less securities qualifying for hybrid treatment (50% debt / 50% equity)

(12) Reflects interest on PV of minimum future operating lease payments (using weighted average cost of debt)

(13) Reflects interest on PV of PPAs (using weighted average cost of debt)

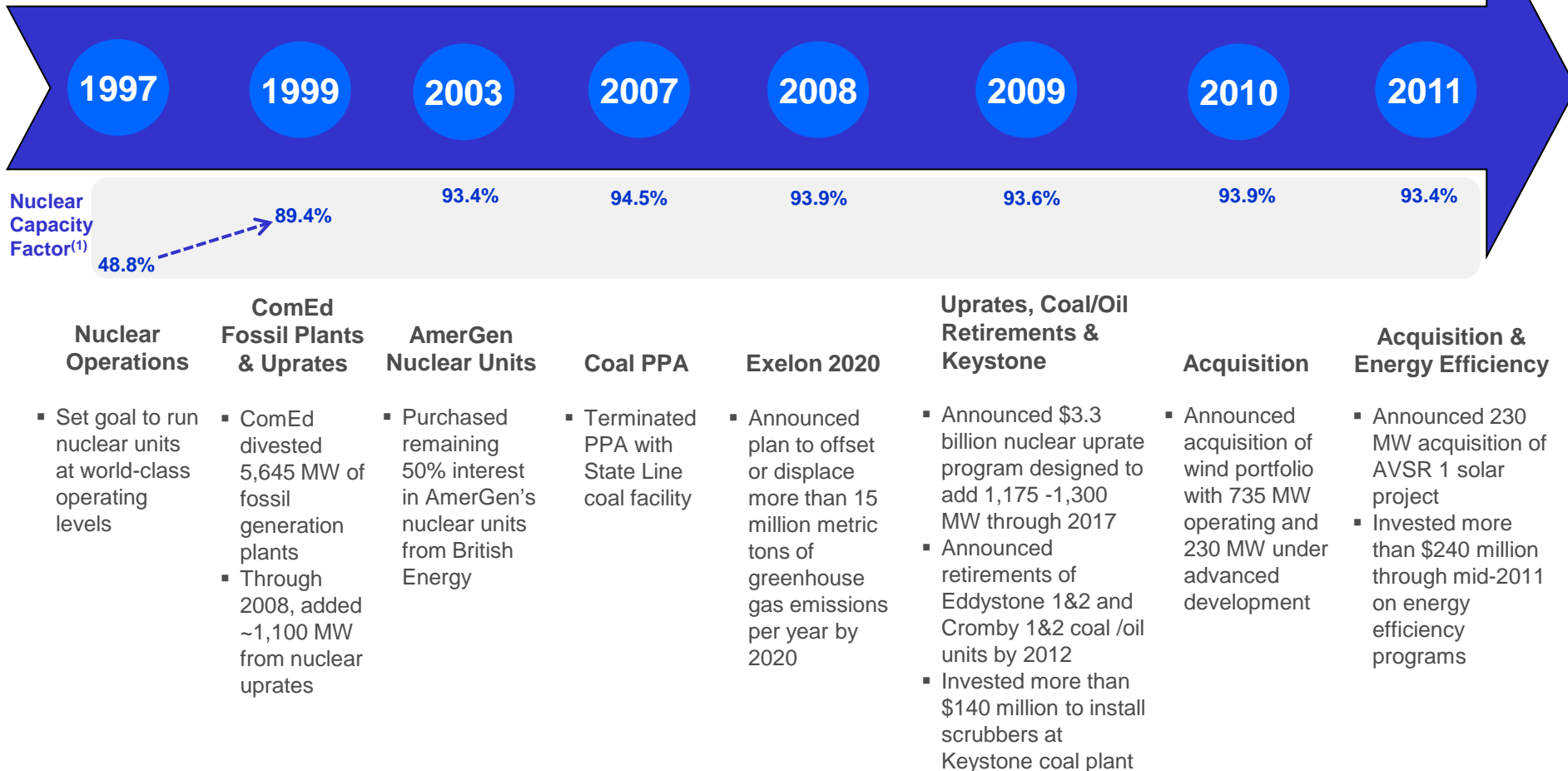
(14) Includes AFUDC / capitalized interest and interest on securities qualifying for hybrid treatment (50% debt / 50% equity)

(15) Includes interest on securities qualifying for hybrid treatment (50% debt / 50% equity)



Environmental

Exelon's Clean Fleet Is a Product of Long-Term Planning



Exelon has made numerous investment decisions over time to prepare for the country's mandated transition to cleaner air, and will invest nearly \$5 billion in cost-efficient, clean energy products from 2010 to 2015

(1) Capacity factors in 1997, 1998 and 1999 represents Unicom nuclear units' performance, and 2011 data represents performance through 9/30/11 for Exelon's nuclear units.

EPA Rulemaking Timeline



CSAPR

- Targets reductions in SO_2 and NO_x to downwind states
- Compliance standards can be met with a variety of controls
- Modest changes proposed but no change in compliance timing

Air Toxic Rules

- Targets mercury and other toxic air pollutants
- Rules provide certainty to industry
- 3-year implementation period provides adequate time to invest in required technology

316(b) Rules

- Targets the cooling water intake structures
- Technology decisions based on site-specific factors, and cost-benefit analysis
- Implementation of cooling towers not mandated

2010

Draft CSAPR issued

2011

Draft Air Toxic rules issued

Draft 316(b) rules issued

Final CSAPR Issued

Final Air Toxic Rules Expected

2012

Compliance with CSAPR

2015

Compliance with Air Toxics Rule

2016

Phase in of Compliance with 316(b) Rules

EPA is committed to rulemaking timeline as mandated under Clean Air Act

Myths & Facts about EPA Clean Air Rules



Topic	Myth	Fact	Supporting Facts
Jobs	<ul style="list-style-type: none"> Jobs will be lost during the economic recovery 	<ul style="list-style-type: none"> Between 2010 and 2015, the new jobs created through investments spurred by the EPA clean air rules will more than offset any job reductions from plant retirements 	<ul style="list-style-type: none"> A June 2011 Economic Policy Institute report concludes that the Toxics Rule will have a modest positive net impact on overall employment
Reliability	<ul style="list-style-type: none"> Plant retirements will lead to rolling blackouts Blanket delay of the rules is the only option to prevent local reliability issues 	<ul style="list-style-type: none"> Reliability of the electric system will not be compromised If and when necessary, state and federal regulators have tools to mitigate any issues 	<ul style="list-style-type: none"> PJM August 2011 report finds that resource adequacy will not be at risk in spite of projected retirements PJM May 2011 RPM forward capacity auction results indicate that there will be ample electricity after proposed EPA rules take effect in 2015 Clean Air Act provides an opportunity for a 1-year extension to install pollution controls U.S. Secretary of Energy has authority to order units to operate on a limited basis in emergency situations
Timeline	<ul style="list-style-type: none"> The rules are a surprise and utilities need more time to plan Utilities don't have enough time to install pollution controls 	<ul style="list-style-type: none"> Companies have known about these rules for almost decade and most, including Exelon, have planned accordingly and invested billions of dollars Utilities have installed pollution controls in less than 3 years 	<ul style="list-style-type: none"> The Hazardous Air Pollutants (HAP) regulations have been in the pipeline for more than 10 years and about 60% of coal-burning plants have already installed controls Most controls like Activated Carbon Injection (ACI) and Dry Sorbent Injection (DSI), can be installed in 2 years or less, and companies will have 3 years to complete installation until the Air Toxic rules take effect in 2015
Control Technology	<ul style="list-style-type: none"> Pollution control technology is not proven 	<ul style="list-style-type: none"> Pollution control technology is already in use and widely available 	<ul style="list-style-type: none"> The industry has extensive experience installing and operating a range of control technologies

Arguments used to recommend blanket delays to implementing EPA regulations are not supported by facts

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Generation

Antelope Valley Solar Ranch One Transaction Summary

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- **Antelope Valley Solar Ranch One (AVSR 1)**
 - 230-MW⁽¹⁾ solar photovoltaic (PV) facility located in Los Angeles County
 - Technology: FS Series 3 cadmium telluride (CdTe) PV panels; single-axis tracking system
 - First portion of plant on line in Oct. 2012; fully operational by end of 2013
 - AVSR 1 will be one of the largest solar PV projects in the world
- **Financing**
 - All-in cost of up to \$1.36 billion
 - Up to \$646M of a non-recourse loan guaranteed by U.S. Department of Energy's Loan Programs Office
 - Exelon to invest up to \$713M from closing to the end of 2013 – funded with cash and short-term debt
 - Tax benefits from investment tax credit (ITC) and depreciation provide additional source of cash beginning in 2012
 - Initial investment recovered by 2015
- **Power Purchase Agreement (PPA)**
 - 25-year PPA with Pacific Gas & Electric generates long-term regulated cash flow stream
 - Contract for all output produced by project
- **Structure**
 - AVSR 1 is a wholly owned indirect subsidiary of Exelon Generation



AVSR 1 further diversifies Exelon's clean generation portfolio with a unique entry point into large-scale solar generation with attractive economics

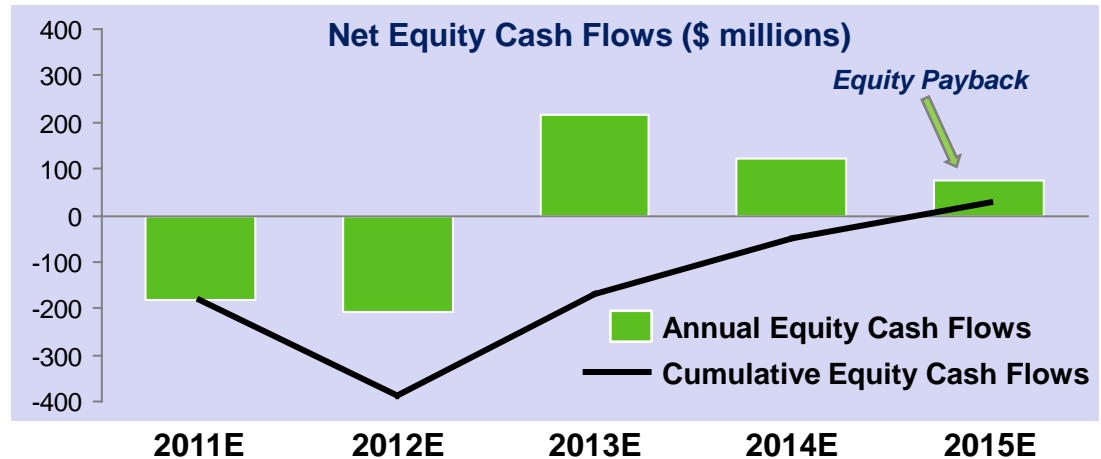
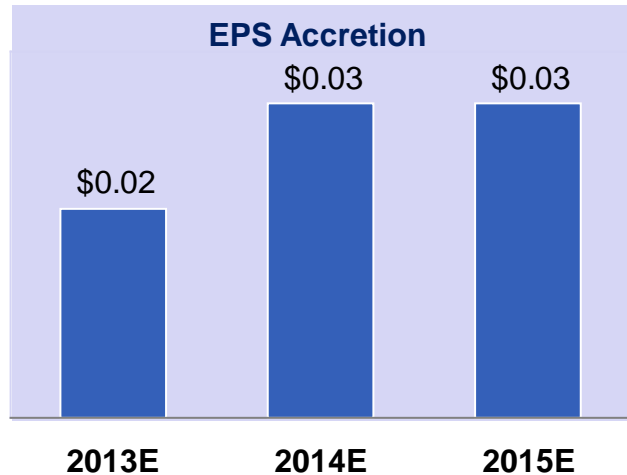
(1) Based on alternating current (AC).

Antelope Valley Solar Ranch One

Attractive Economics

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- Free cash flow accretive beginning in 2013
 - Cash outflows in 2011-2012 during construction mitigated significantly by tax benefits and operating cash inflows received as portions of project come online
- EBITDA run-rate of ~\$75M per year post full commercial operation date
- Expect transaction to have minimal impact on credit metrics

Expect to recover investment by 2015, largely driven by investment tax credits and other tax benefits

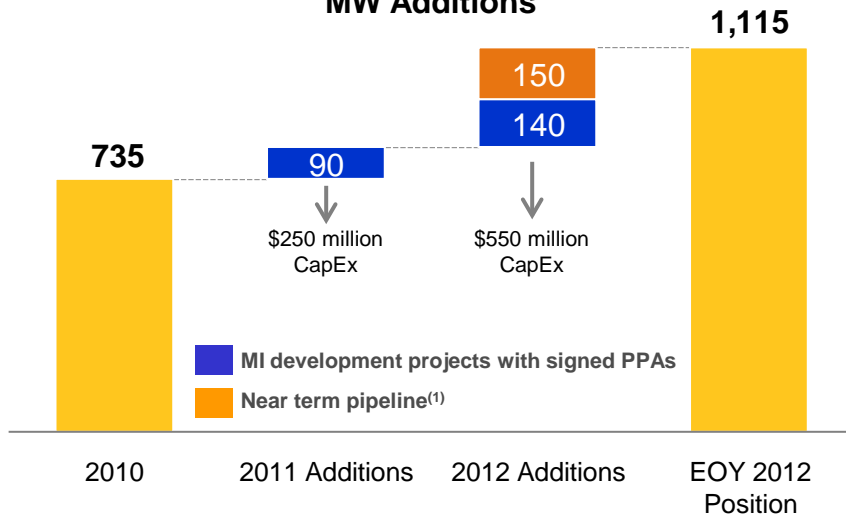
Exelon Wind Development Strategy



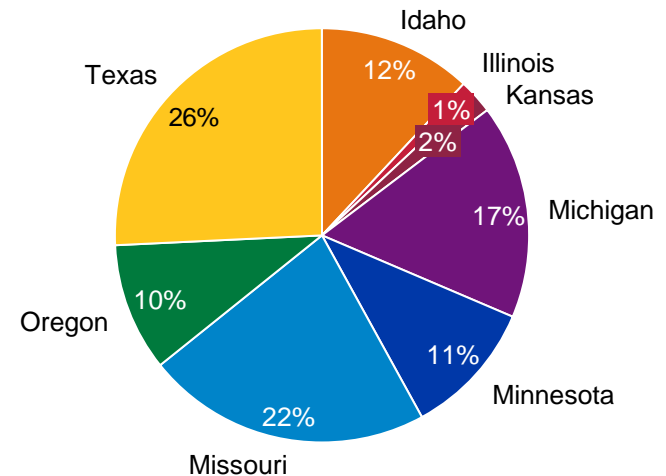
Invest in new wind projects that are primarily hedged via PPAs and meet internal hurdle rates

Focus on geographic diversity to minimize production risk for the overall portfolio

MW Additions



MW by state – 735 MW at EOY 2010



Growth Plans

- Longer term pipeline of 500 to 1,000 MW of wind projects may be developed or acquired over the next five years
 - Several states under consideration, including ID, ND, CA, NM, KS, OK, PA, MN, MI
 - Growth strategy post 2013 assumes tax benefits are extended beyond 2012

Exelon's balance sheet strength and ability to monetize tax benefits are key competitive advantages in the wind development business

(1) New wind development will depend on ability to sign PPAs and meet internal hurdle rates.

Wolf Hollow Acquisition



- Diversifies generation portfolio
 - Expands geographic and fuel characteristics of fleet
 - Advances Exelon and Constellation merger strategy of matching load with generation in key competitive markets
- Creates value for shareholders
 - \$305M purchase price compares favorably to cost of other recent transactions
 - Free cash flow accretive beginning in 2012; earnings and credit neutral
 - Eliminates current above market purchase power agreement (PPA) with Wolf Hollow
 - Enhances opportunity to benefit from future market heat rate expansion in ERCOT



- 720 MW Combined Cycle Natural Gas Plant
- Located in Granbury, Texas (near Dallas)

The acquisition of Wolf Hollow strengthens Exelon's position in a valuable Texas market

Growing Clean Generation with Upgrades



Nuclear Upgrade Program Summary

	Est. IRR	Overnight Cost ⁽¹⁾	Approval Process	Project Duration
Megawatt Recovery & Component Upgrades	12-14%	\$790 M	Not required	3-4 Years
MUR (Measurement Uncertainty Recapture)	13-16%	\$330 M	Straight forward approval process	2-3 Years
EPU (Extended Power Upgrade)	10-14%	\$2,155 M	Straight forward approval process	3-6 Years

Executing upgrade projects across our geographically diverse nuclear fleet, and expect to add 99 MW in 2011

Station	Base Case MW	Max Potential MW	MW Online to Date	Year of Full Operation by Unit
MW Recovery & Component Upgrades:				
Quad Cities	97	104	99	2011 / 2010
Dresden	3	3		2013 / 2012
Peach Bottom	25	32		2011 / 2012
Dresden	103	110	19	2012 / 2013
Limerick	4	4		2012 / 2013
Peach Bottom	2	2		2014 / 2015
MUR:				
LaSalle	35	39	39	2011 / 2011
Limerick	33	41	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	134	148		2015 / 2016
LaSalle	303	336		2016 / 2015
Limerick	306	340		2016 / 2017
Total	1,176	1,314	189	

(1) In 2011 dollars. Overnight costs do not include financing costs or cost escalation.

Exelon's Uprate Program Is a Pragmatic Approach to Nuclear Growth



Key Considerations	Exelon Uprate Program	New Merchant Nuclear ⁽²⁾
Overnight cost ⁽¹⁾	\$2,500 – \$2,800 / KW	\$4,500 – \$6,000 / KW
Time to market	2 – 6 years	At least 9 years
O&M cost	No additional O&M cost	\$10 – \$15 / MWh
Ancillary costs – NDT, maintenance capital, etc	Minimal ancillary costs	\$ 2 – \$3 / MWh
Asset diversification	Operational risk spread amongst several assets	Operational risk concentrated to single asset
Market diversification	Diversify revenue source amongst several power markets/ regions	Market risk concentrated to one location
Market timing risk	Lower risk due to phased execution	Risk of hitting low commodity cycle
Regulatory approval	1 – 2 years review period	3-year minimum review period
Financing Source	Leverage balance sheet strength	Loan guarantees needed
Development flexibility	Ability to respond to changing market / financial conditions	Much less flexibility to cancel

Exelon's uprate program is a proven approach to add clean generation to the portfolio, and it provides flexibility to respond to changing economic and market conditions

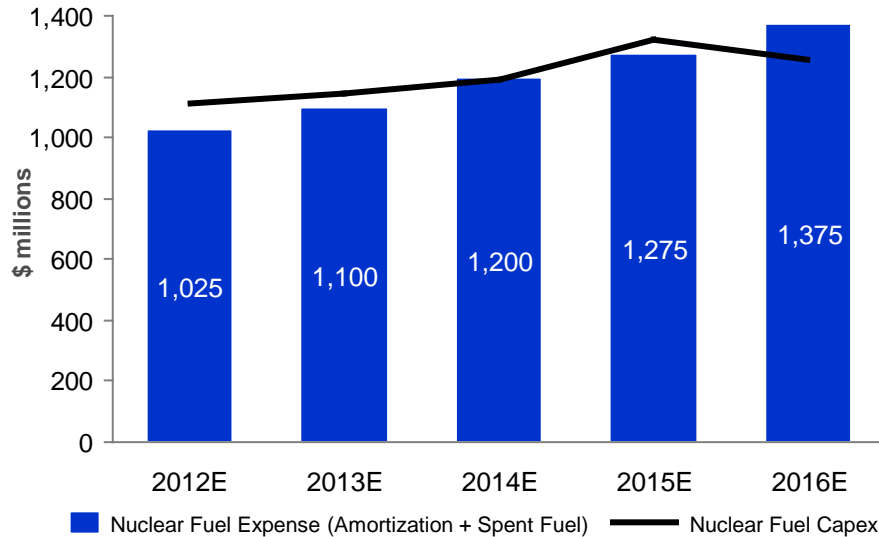
(1) In 2011 dollars. Overnight costs do not include financing costs or cost escalation.

(2) Cost estimates are based on Exelon's internal projections for new merchant nuclear.

Nuclear Fuel and Outage Management



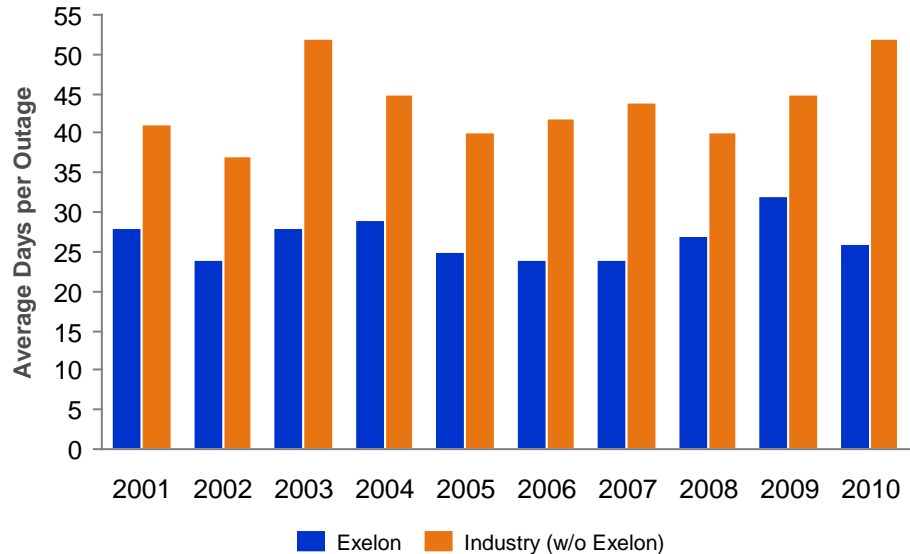
Effectively Managing Nuclear Fuel Spend



Note: At 100%, excluding Salem. Excludes costs reimbursed under the settlement agreement with the DOE.

- Exelon Nuclear's uranium demand is 100% physically hedged through 2015
- Nuclear fuel expenditures are capitalized in the period of investment
- Capitalized nuclear fuel is amortized to expense over three refueling outage cycles

Industry Leading Refueling Outage Duration⁽¹⁾



- All Exelon owned units are on a 24-month refueling cycle except for Braidwood, Byron and Salem, which are on 18-month cycles
- 12 planned refueling outages (six in Spring and six in Fall) in 2011, including two at Salem
- 10 planned refueling outages (four in Spring and six in Fall) in 2012, including one at Salem

(1) Exelon data includes Salem. The 2009 average includes 23 days of TMI outage that extended into 2010 for a steam generator replacement.

Post Fukushima: NRC Staff Review Process and Anticipated Implications

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- Exelon's actions are aligned with coordination that is taking place across the U.S. nuclear industry
- Exelon agrees with the Commission's recognition of the need for performance-based, flexible approaches to address site-specific circumstances

Key Tier 1 Staff Recommendations

Recommendation	Anticipated Impact on Exelon	Exelon Actions
Protect back up equipment from external events and provide equipment for multi-unit events (B5b)	In or beyond 2012: Develop plans for reasonably protecting back up equipment and evaluate new regulatory requirements to determine whether additional backup or upgraded equipment is required	2011: Obtain additional back up equipment to establish multi-unit capability at dual unit sites and perform evaluations of back up equipment storage locations at all sites to minimize vulnerability to external events 2012: Participate in stakeholder process on equipment and "reasonable protection" requirements
Spent Fuel Pool (SFP) instruments	In or beyond 2012: Design and install SFP instrumentation	2011: Conducting preliminary evaluation of available technology 2012: Participate in stakeholder process to define requirements. Potentially begin conceptual design and/or installation, in line with the schedule to be identified by the NRC
Reliable hardened vents for Mark I and II containment	Beyond 2012: Evaluate reliability of existing Mark I hardened vents ⁽¹⁾ Design and install new Mark II hardened vents as required in final order	2011: Evaluate whether procedures or staging can be updated to improve ease of using hardened containment vents within current plant configurations 2012: Participate in developing stakeholder process on hardened vent criteria and begin conceptual design
Improve station blackout coping time	2014 and beyond: Begin implementing requirements of rule	2011: Analyzing current extended station blackout capability and developing actions to improve capability 2012-2013: Participate in stakeholder process on coping time requirements

- Other Staff Recommendations:** Implement other tier 1 recommendations from 2013 – 2016

Exelon expects the costs to comply with NRC recommendations to be manageable

(1) All Exelon units with Mark I containment have hardened vents.

Exelon Nuclear Fleet Overview



	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 (Unit 1 and 2)	PWR Concrete/Steel Lined	Kankakee River	Expect to file application in 2013/ 2026, 2027	100%	Dry Cask (Fall 2011)
	Byron, IL (Unit 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 (Unit 2 and 3)	BWR Steel Vessel / Mark I	Kankakee River	Renewed / 2029, 2031	100%	Dry Cask
	LaSalle, IL (Unit 1 and 2)	BWR Concrete/Steel Lined / Mark II	Illinois River	2022, 2023	100%	Dry Cask
	Quad Cities, IL (Unit 1 and 2)	BWR Steel Vessel / Mark I	Mississippi River	Renewed / 2032	75% Exelon, 25% Mid-American Holdings	Dry Cask
Mid-Atlantic	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
	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

Exelon pursues license extensions well in advance of expiration to ensure adequate time for review by the NRC

- (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 Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. The current NRC license for Oyster Creek expires in 2029.

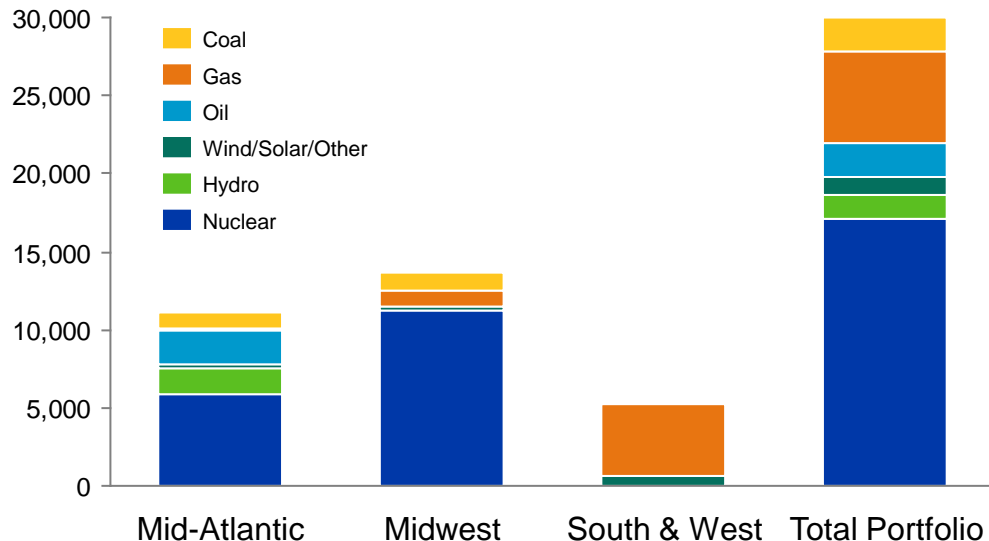
Flexible Hedging Program and Diverse Sales Mix Enhance Portfolio Value

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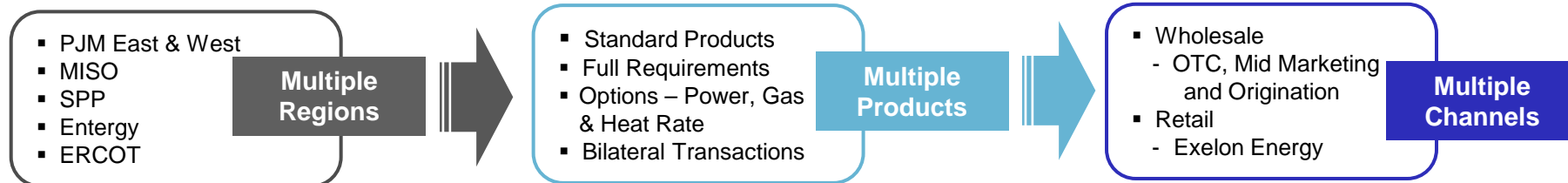
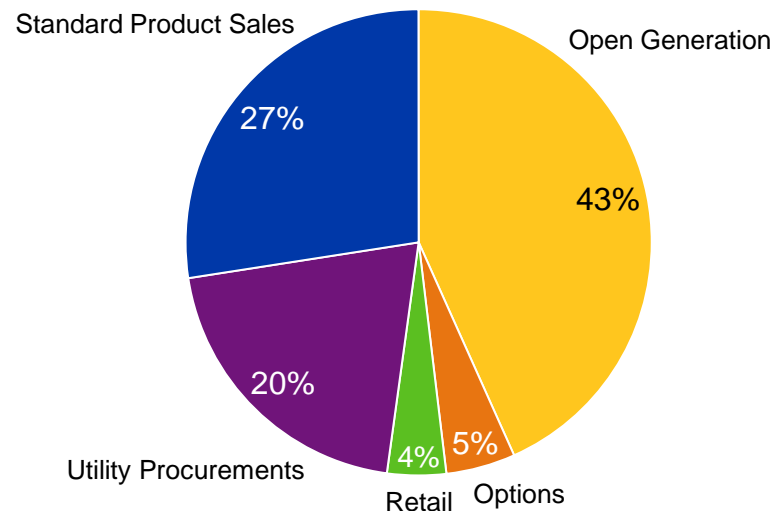
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Current Owned & Contracted Generation Capacity by Fuel Type⁽¹⁾



2012-2014 Sales as a Percentage of Expected Generation⁽²⁾



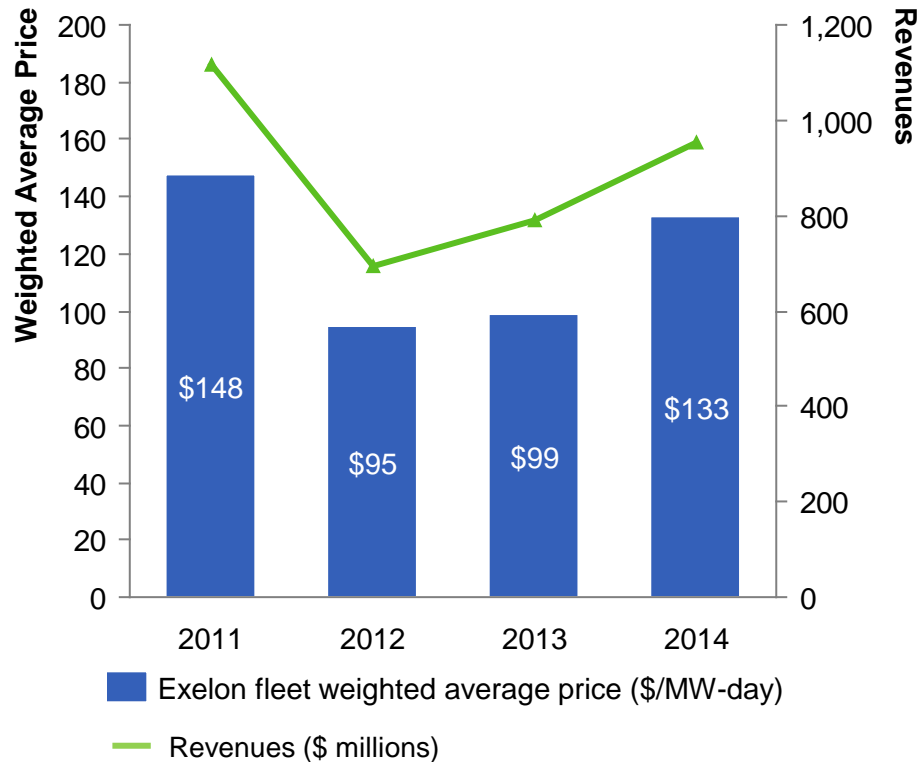
(1) Reflects owned and contracted generation (in MW) as of 9/30/2011. Excludes PPA with Tenaska Georgia Partners.

(2) Data as of 9/30/2011. Utility procurements includes Full Requirements, Block Energy and Power Sales Agreements.

Reliability Pricing Model (RPM)



PJM RPM Capacity Prices and Revenues⁽¹⁾



RPM Update

- The Brattle Group assessment of the PJM RPM market indicates that it has achieved resource adequacy and reduced costs by fostering competition. The Brattle Group proposed changes that appear to have some traction include:
 - Modify the 2.5% holdback so it increases the amount of generation and premium DR products that will clear in the base residual auction
 - Update the methodology of calculating the E&AS offset used in Net CONE for a CT to be consistent with actual margins
 - Increase the slope of the demand curve when supply falls below reserve margin
- AEP Ohio and Duke Ohio are expected to move their capacity assets and load from their FRR plan into RPM
- NJ and MD have both issued RFPs for new CCGTs to be built in their states, which could possibly be bid into the 15/16 BRA. Currently, these CCGT projects will be subject to MOPR when bidding into the capacity auction
- PJM reports for PY 14/15 indicate that elevated bidding most likely reflected environmental compliance costs and highlight the benefits of Exelon's regionally balanced portfolio

Exelon benefits from a balanced capacity position across PJM and has significant revenues locked in via the PJM capacity market

(1) Weighted average \$/MW-Day would apply if all owned generation cleared. Prices are rounded. Revenues reflect capacity cleared in base and incremental auctions.
 Note: For definitions of RPM related terms, refer to PJM Manual 18 for capacity markets at <http://pjm.com/documents/manuals.aspx>



Exelon Generation Hedging Disclosures (as of September 30, 2011)

Important Information



The following slides are intended to provide additional information regarding the hedging program at Exelon Generation and to serve as an aid for the purposes of modeling Exelon Generation's gross margin (operating revenues less purchased power and fuel expense). The information on the following slides is not intended to represent earnings guidance or a forecast of future events. In fact, many of the factors that ultimately will determine Exelon Generation's actual gross margin are based upon highly variable market factors outside of our control. The information on the following slides is as of September 30, 2011. We update this information on a quarterly basis.

Certain information on the following slides is based upon an internal simulation model that incorporates assumptions regarding future market conditions, including power and commodity prices, heat rates, and demand conditions, in addition to operating performance and dispatch characteristics of our generating fleet. Our simulation model and the assumptions therein are subject to change. For example, actual market conditions and the dispatch profile of our generation fleet in future periods will likely differ – and may differ significantly – from the assumptions underlying the simulation results included in the slides. In addition, the forward-looking information included in the following slides will likely change over time due to continued refinement of our simulation model and changes in our views on future market conditions.

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Portfolio Management Objective

Align Hedging Activities with Financial Commitments



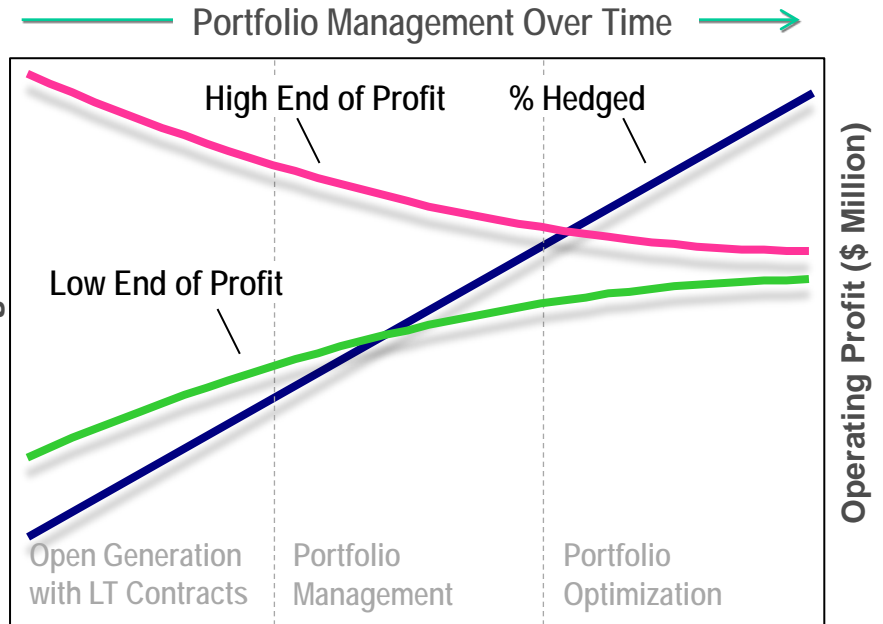
- **Exelon's hedging program is designed to protect the long-term value of our generating fleet and maintain an investment-grade balance sheet**

- Hedge enough commodity risk to meet future cash requirements if prices drop
- Consider: financing policy (credit rating objectives, capital structure, liquidity); spending (capital and O&M); shareholder value return policy

- **Consider market, credit, operational risk**

- **Approach to managing volatility**

- Increase hedging as delivery approaches
- Have enough supply to meet peak load
- Purchase fossil fuels as power is sold
- Choose hedging products based on generation portfolio – sell what we own



- **Power Team utilizes several product types and channels to market**

- | | |
|---|---------------------|
| • Wholesale and retail sales | • Heat rate options |
| • Block products | • Fuel products |
| • Load-following products and load auctions | • Capacity |
| • Put/call options | • Renewable credits |

Exelon Generation Hedging Program



- **Our normal practice is to hedge commodity risk on a ratable basis over the three years leading to the spot market**
 - Carry operational length into spot market to manage forced outage and load-following risks
 - By using the appropriate product mix, expected generation hedged approaches the mid-90s percentile as the delivery period approaches
 - Participation in larger procurement events, such as utility auctions, and some flexibility in the timing of hedging may mean the hedge program is not strictly ratable from quarter to quarter

**Percentage of Expected
Generation Hedged**

$$= \frac{\text{Equivalent MWs Sold}}{\text{Expected Generation}}$$

- How many equivalent MW have been hedged at forward market prices; all hedge products used are converted to an equivalent average MW volume
- Takes ALL hedges into account whether they are power sales or financial products

Exelon Generation Open Gross Margin and Reference Prices



	2012	2013	2014
Estimated Open Gross Margin (\$ millions)⁽¹⁾⁽²⁾	\$5,150	\$5,900	\$6,550

Reference Prices⁽¹⁾

Henry Hub Natural Gas (\$/MMBtu)	\$4.24	\$4.80	\$5.13
NI-Hub ATC Energy Price (\$/MWh)	\$33.69	\$36.49	\$39.25
PJM-W ATC Energy Price (\$/MWh)	\$45.46	\$48.45	\$51.47
ERCOT North ATC Spark Spread (\$/MWh) ⁽³⁾	\$4.32	\$4.69	\$5.69

(1) Based on September 30, 2011 market conditions.

(2) Gross margin is defined as operating revenues less fuel expense and purchased power expense, excluding the impact of decommissioning and other incidental revenues. Open gross margin is estimated based upon an internal model that is developed by dispatching our expected generation to current market power and fossil fuel prices. Open gross margin assumes there is no hedging in place other than fixed assumptions for capacity cleared in the RPM auctions and uranium costs for nuclear power plants. Open gross margin contains assumptions for other gross margin line items such as various ISO bill and ancillary revenues and costs and PPA capacity revenues and payments. The estimation of open gross margin incorporates management discretion and modeling assumptions that are subject to change.

(3) ERCOT North ATC spark spread using Houston Ship Channel Gas, 7,200 heat rate, \$2.50 variable O&M.

Generation Profile



	2012	2013	2014
Expected Generation (GWh)⁽¹⁾	169,600	166,100	166,100
Midwest	98,300	96,100	95,400
Mid-Atlantic	56,800	56,100	55,800
South & West	14,500	13,900	14,900
Percentage of Expected Generation Hedged⁽²⁾	85-88%	56-59%	23-26%
Midwest	85-88	56-59	22-25
Mid-Atlantic	88-91	57-60	22-25
South & West	68-71	49-52	38-41
Effective Realized Energy Price (\$/MWh)⁽³⁾			
Midwest	\$41.00	\$40.00	\$38.00
Mid-Atlantic	\$50.00	\$50.50	\$52.00
South & West	\$1.00	\$0.00	(\$1.50)

(1) Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted for capacity. Expected generation is based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 10 refueling outages in 2012 and 2013 and 11 refueling outages in 2014 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 93.5%, 93.3% and 93.4% in 2012, 2013 and 2014 at Exelon-operated nuclear plants. 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.

(2) Percent of expected generation hedged is the amount of equivalent sales divided by the expected generation. Includes all hedging products, such as wholesale and retail sales of power, options, and swaps. Uses expected value on options. Reflects decision to permanently retire Cromby Station and Eddystone Units 1&2 as of May 31, 2011.

(3) 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.

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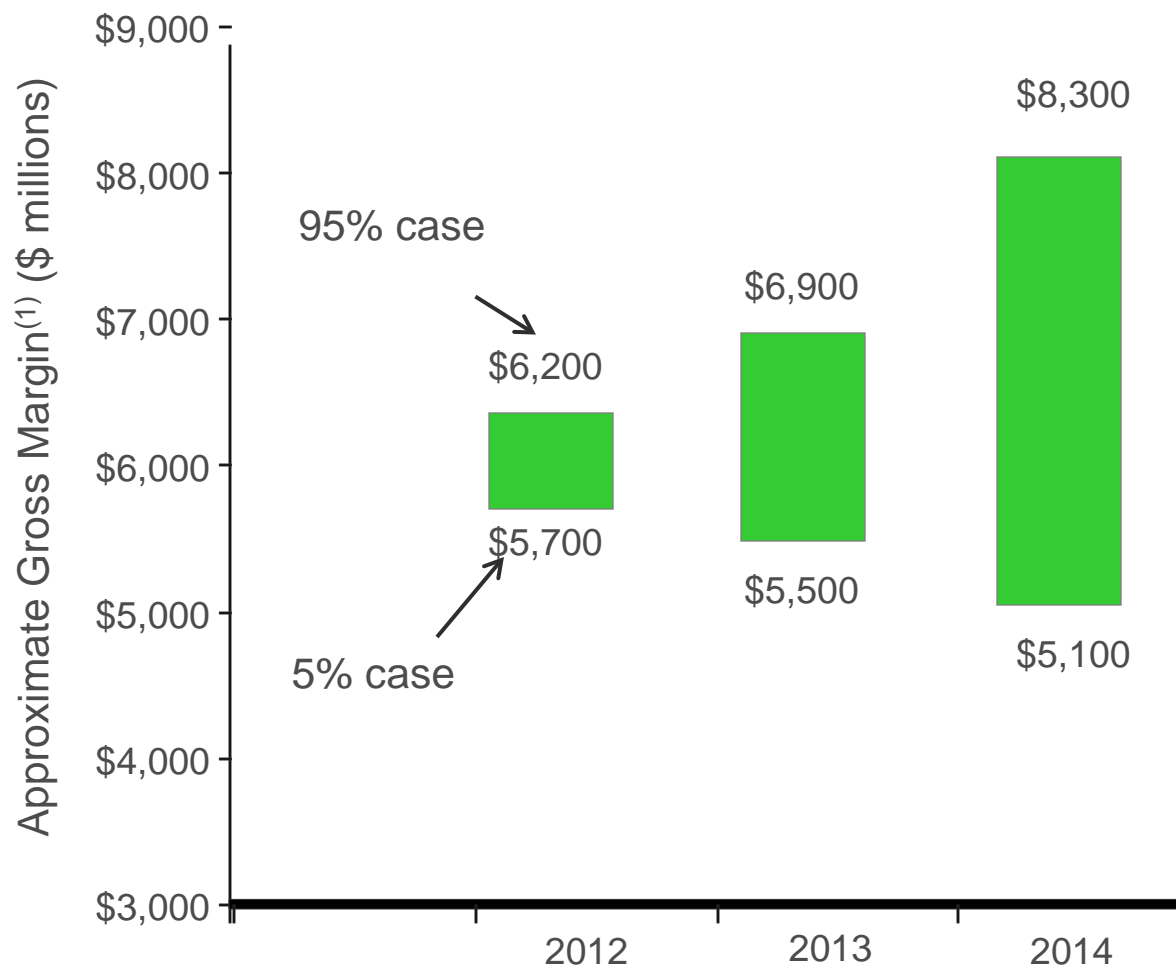
Exelon Generation Gross Margin Sensitivities (with Existing Hedges)



	2012	2013	2014
Gross Margin Sensitivities with Existing Hedges (\$ millions)⁽¹⁾			
Henry Hub Natural Gas			
+ \$1/MMBtu	\$65	\$305	\$610
- \$1/MMBtu	\$(30)	\$(265)	\$(580)
<hr/>			
NI-Hub ATC Energy Price			
+\$5/MWH	\$70	\$210	\$380
-\$5/MWH	\$(50)	\$(205)	\$(375)
<hr/>			
PJM-W ATC Energy Price			
+\$5/MWH	\$40	\$145	\$235
-\$5/MWH	\$(35)	\$(140)	\$(230)
<hr/>			
Nuclear Capacity Factor			
+1% / -1%	+/- \$45	+/- \$50	+/- \$55

(1) Based on September 30, 2011 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.

Exelon Generation Gross Margin Upside / Risk (with Existing Hedges)



(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 2012, 2013 and 2014 do not represent earnings guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years. The price distributions that generate this range are calibrated to market quotes for power, fuel, load following products, and options as of September 30, 2011.

Illustrative Example

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of Modeling Exelon Generation 2012 Gross Margin (with Existing Hedges)



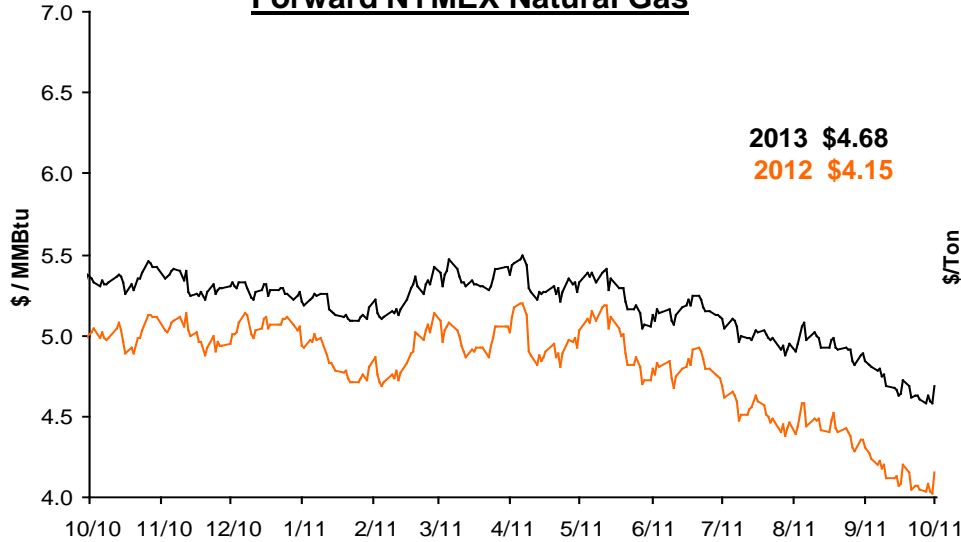
	Midwest	Mid-Atlantic	South & West
Step 1 Start with fleetwide open gross margin	<div> <div></div> <div>\$5.15 billion</div> <div></div> </div>		
Step 2 Determine the mark-to-market value of energy hedges	98,300GWh * 86% * (\$41.00/MWh-\$33.69MWh) = \$0.62 billion	56,800GWh * 90% * (\$50.00/MWh-\$45.46MWh) = \$0.24 billion	14,500GWh * 69% * (\$1.00/MWh-\$4.32MWh) = \$(0.03) billion
Step 3 Estimate hedged gross margin by adding open gross margin to mark-to-market value of energy hedges	Open gross margin: MTM value of energy hedges: Estimated hedged gross margin:	\$5.15 billion <u>\$0.62billion + \$0.24billion + \$(0.03) billion</u> \$5.98 billion	

Market Price Snapshot

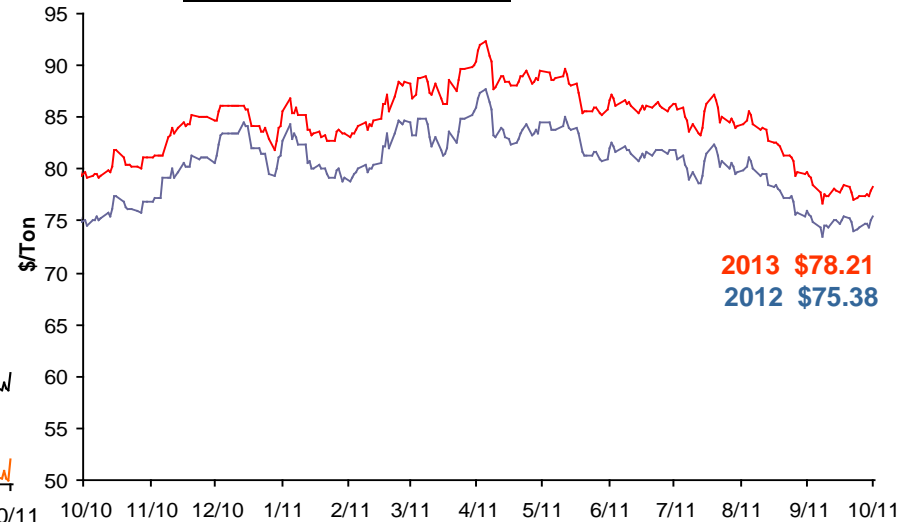
Rolling 12 months, as of October 28th 2011. Source: OTC quotes and electronic trading system. Quotes are daily.



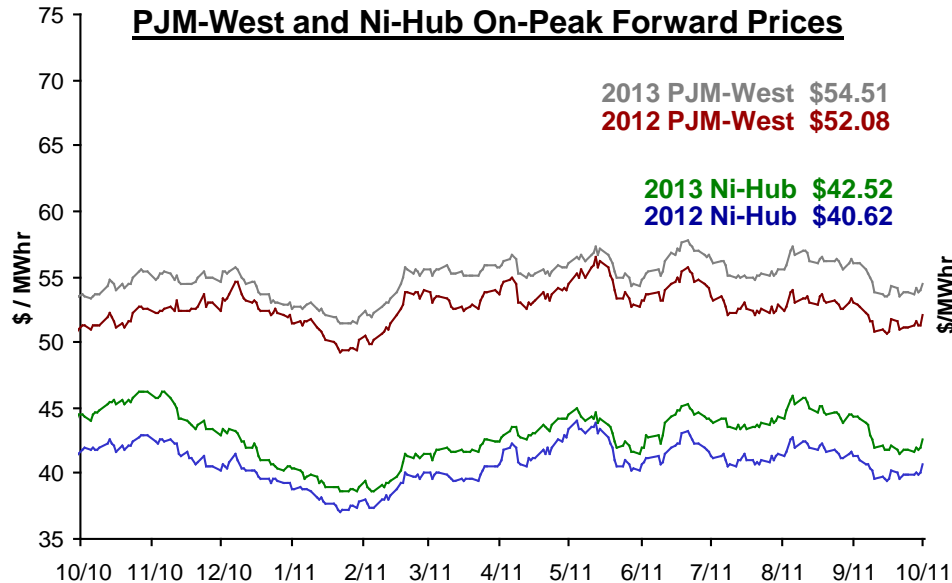
Forward NYMEX Natural Gas



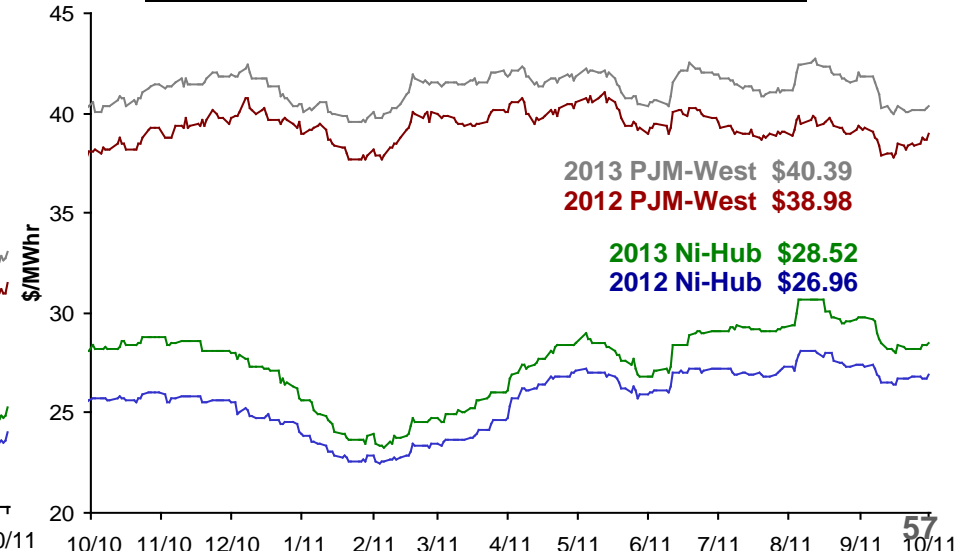
Forward NYMEX Coal



PJM-West and Ni-Hub On-Peak Forward Prices



PJM-West and Ni-Hub Wrap Forward Prices

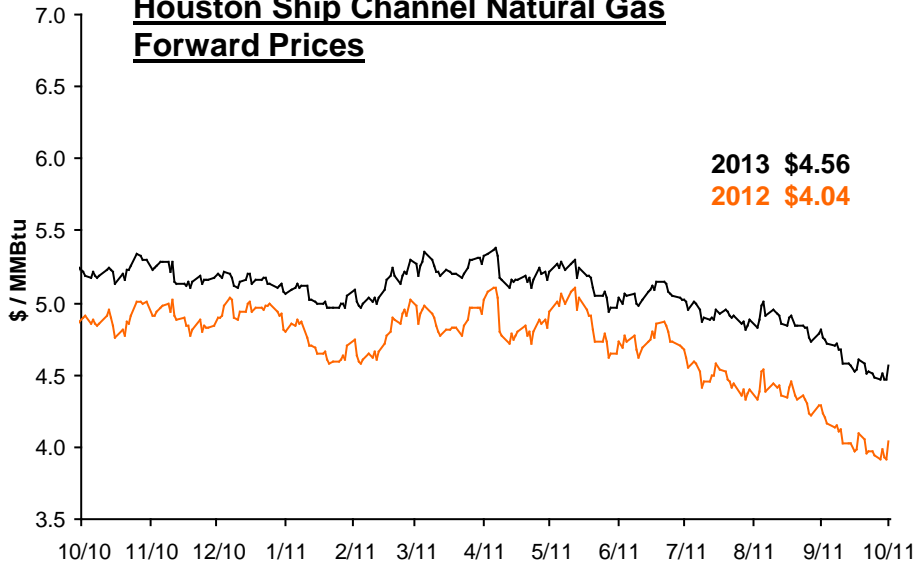


Market Price Snapshot

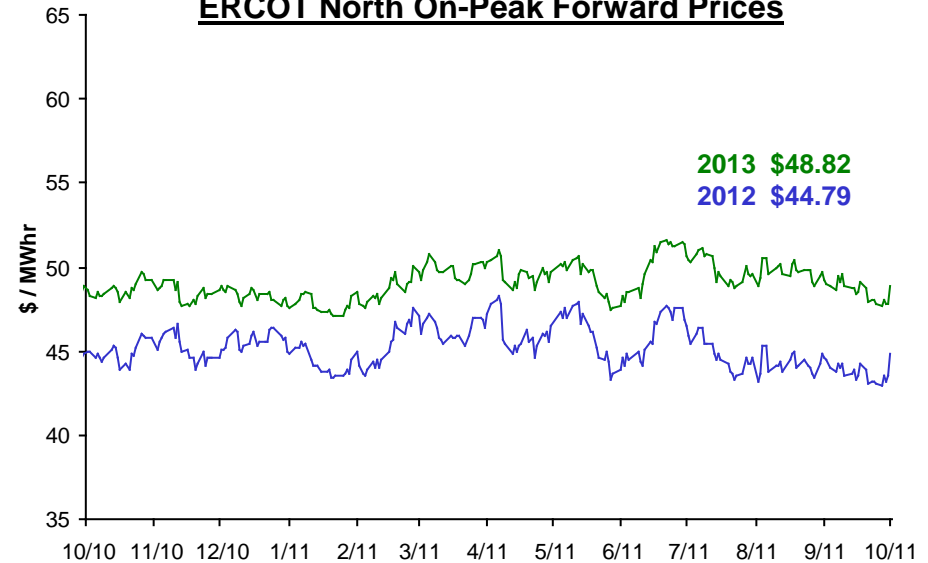
Rolling 12 months, as of October 28th 2011. Source: OTC quotes and electronic trading system. Quotes are daily.



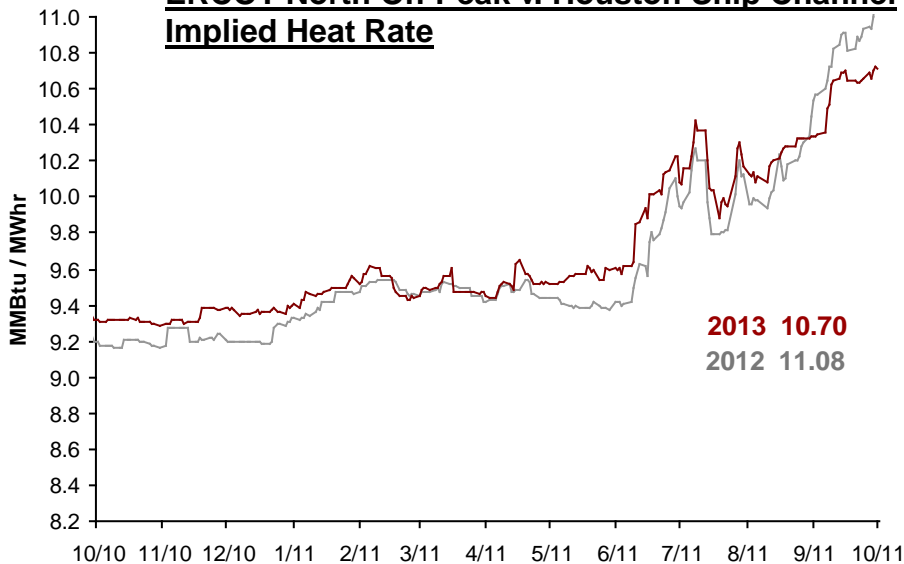
Houston Ship Channel Natural Gas Forward Prices



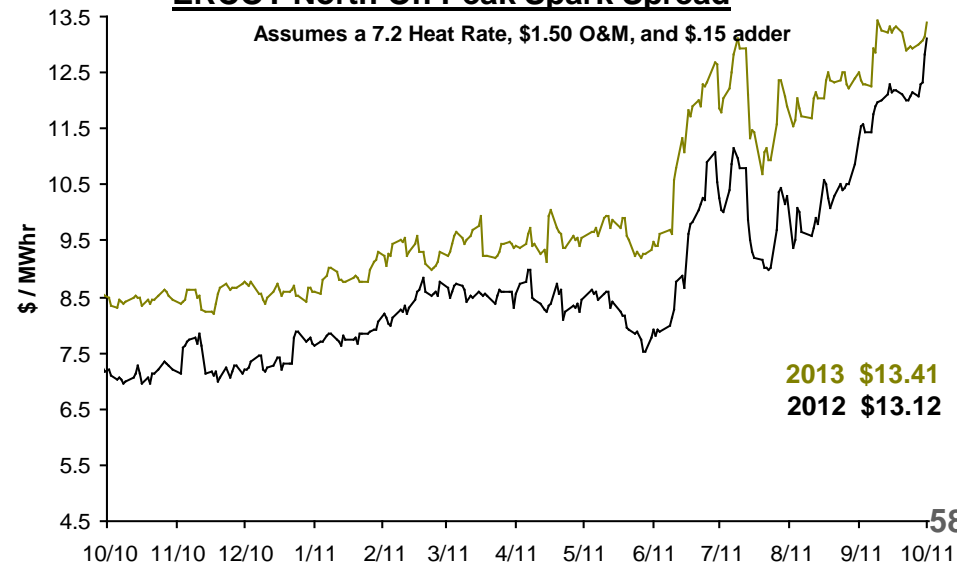
ERCOT North On-Peak Forward Prices



ERCOT North On-Peak v. Houston Ship Channel Implied Heat Rate



ERCOT North On Peak Spark Spread

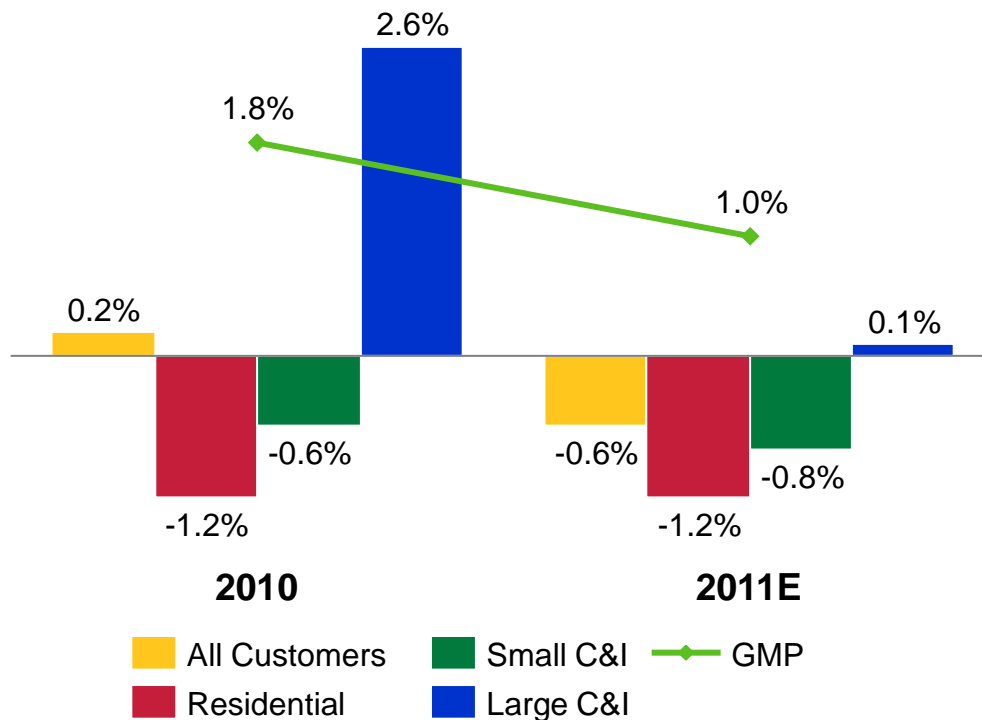




An Exelon Company

ComEd Load Trends

Weather-Normalized Load YoY Growth



Economic Forecast of Drivers that Influence Load

Driver or Indicator ⁽¹⁾	2012 Outlook
Gross Metro Product (GMP)	1.8% growth in GMP, which reflects slow growth economy
Housing Starts	Chicago housing market is expected to remain weak with no meaningful improvement until 2014 as "deleveraging" continues to be a drag on the economy
Manufacturing	2.3% increase in manufacturing employment
Unemployment	Little improvement expected in 2012 vs. 2011
Energy Efficiency	Continued expansion of EE programs with ~1% reduction to usage

2012 expected to be another transition year as regional indicators point to an economy that continues to grow slowly

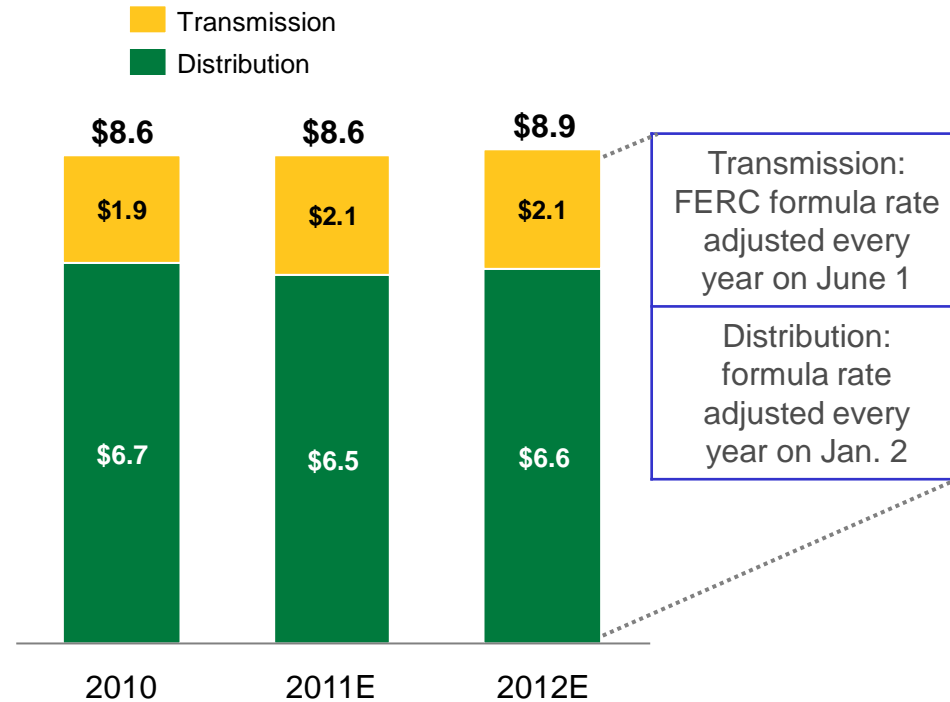
ComEd Rate Case Results and Rate Base

Recent Rate Cases

Electric Distribution	Current Rates
Rates Effective	June 1, 2011
Test Year	2009 pro forma
Rate Base ⁽¹⁾	\$6,549 million
ROE	10.5%
Equity %	47%

Transmission	FERC Formula Rate
Rates Effective	June 1, 2011
Test Year	2010 pro forma
Rate Base	\$2,054 million
ROE	11.5%
Equity %	55%

Rate Base in Rates End of Year Balance (\$ in billions)



	2010	2011E
Equity Ratio	~45%	~43%
Earned ROE	10.6%	9 - 10%

Long-Term Target
45 - 50% ⁽²⁾
Based on 30-yr. US Treasury ⁽³⁾

Note: Amounts may not add due to rounding.

(1) Amounts include pro forma adjustments. On September 30, 2010, the Illinois Appellate Court ruled with regard to ComEd's 2007 distribution rate case and held that the ICC abused its discretion in not reducing ComEd's rate base to account for an additional 18 months of accumulated depreciation while including pro forma plant additions post-test year through that period. On May 24, 2011, the ICC issued an order in ComEd's 2010 rate case, following the Court's position on the post-test year accumulated depreciation issue.

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

(3) 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.

Illinois Energy Modernization Act

Key Provisions of Legislation – SB 1652 and HB 3036 (“Trailer Bill”)⁽¹⁾

- Incremental investment of \$2.6B of capital over next 10 years
- Incorporates an annual formula rate proceeding, similar to FERC transmission rate
 - Includes an annual reconciliation of costs included in rates with actual costs incurred
 - Rates go into effect after ICC review (~8 months)
- Legislation sunsets in May 2014 if the residential rate increases by more than an average of 2.5% per year and terminates on December 31, 2017 without an extension from the General Assembly

Benefits to Customers and to Illinois

- Expect to prevent 700,000 service interruptions per year
- Put a smart meter in every home and provide extensive consumer education
- Significantly improve meter reading and reduce frequency and duration of outages
- Contribute \$10M per year for 5 years to fund customer assistance programs
- Contribute \$15M to Science and Energy Innovation Trust Fund to fund energy innovation
- Create 2,000 full-time equivalent jobs at the peak of the investment cycle
- Enhance the economic competitiveness of Illinois; make the state better positioned to attract businesses and jobs

Timeline of Filings

By November 10, 2011	ComEd makes initial performance-based rate filing based on a 2010 test year plus 2011 net plant additions
By May 31, 2012	ICC issues order based on its review of the prudence and reasonableness of costs
May 2012	ComEd files rate filing with 2011 test year plus 2012 net plant additions and 2011 reconciliation
January 2, 2013	Adjusted rates take effect after ICC review
Each May and January thereafter	Annual rate filings take place in May; new rates effective in January after ICC review

Innovative regulatory and legislative strategy will benefit customers, improve the transparency of the ratemaking process and enable economic development in Illinois

(1) All information provided assumes the Trailer Bill is enacted into law in addition to SB 1652.

Illinois Energy Modernization Act – Key Impacts

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Estimated Capital Expenditures

(\$ in millions)	Years 1-5	Years 6-9	Total
Smart Meter/Smart Grid	\$850	\$450	\$1,300
Infrastructure Upgrades	\$1,300	\$0	\$1,300
Total	\$2,150	\$450	\$2,600

Financial Statement Impact

- ComEd will record a regulatory asset and income statement adjustments to reflect the implementation of the legislation regarding amortization of storm costs and the reconciliation
 - ~\$50-\$60M of 2011 storm costs will be deferred over 5 years
 - Revenue requirement reconciliation estimated at \$20-\$30M which will not be billed to customers until 2013
 - \$15M contribution required to fund the Illinois Science and Energy Innovation Trust
- ~\$30-\$40M of after-tax earnings impact will be recorded in 2011
 - 2011 earnings dependent on final costs, rate base and Treasury rates

ROE – Formula Rate

- Initial Filing (Nov. 2011): 2010 + 2011 net plant additions:
 - 12-month average of the 30-year US Treasury yield plus 580 basis point risk premium
 - 4.25% (Jan. to Dec. 2010) average Treasury yield
- Second Filing (May 2012): 2011 + 2012 plant additions:
 - 12-month average of the 2011 30-year US Treasury yield plus 580 basis points
 - 2011 reconciliation allowed ROE includes 590 basis point risk premium
- Subsequent Filings (May of each year):
 - 12-month average of the 30-year US Treasury yield plus 580 basis points for both annual rate and reconciliation filings
- ROE can be reduced by up to 30 basis points if performance metrics are not met
- Includes a 50 basis point collar as defined in the legislation

Illinois Power Agency (IPA) Procurement

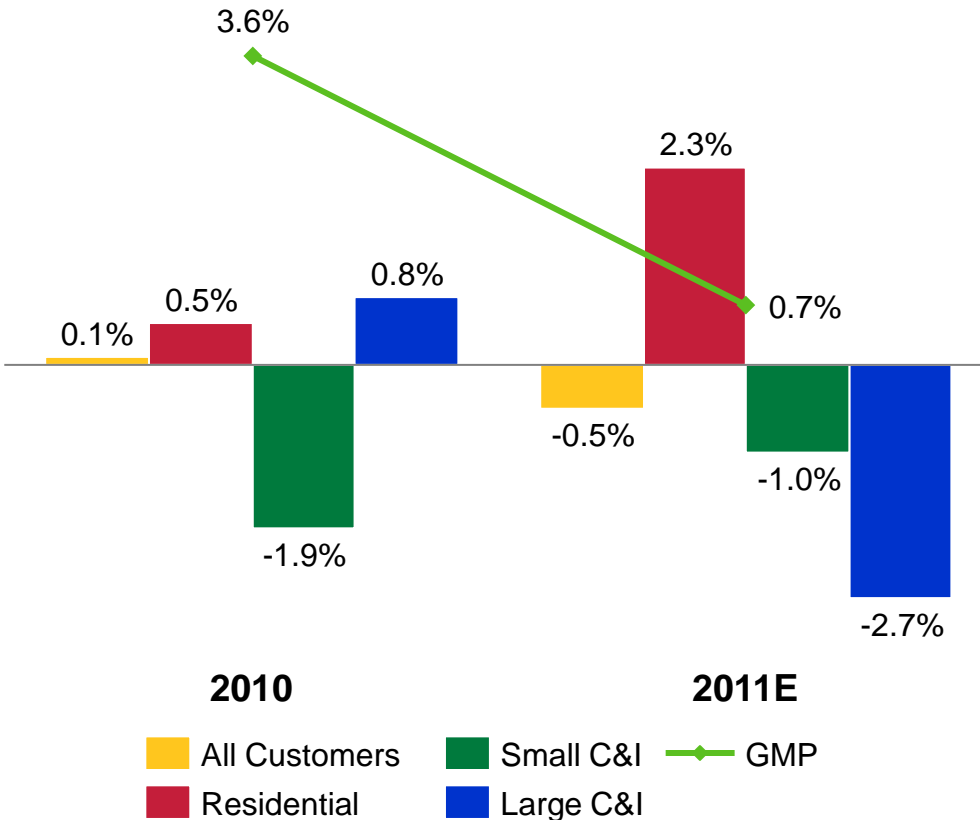
- Current IPA procurement process maintained with annual events procuring one-third of the load over a three-year period
- Legislation allows the IPA to conduct a special event to procure power covering load through May 2017 if resulting prices are deemed to be beneficial to full-service customers
- Energy contracts, if ultimately procured for ComEd, will be multi-year with pricing escalating at 2.5% per annum



An Exelon Company

PECO Load Trends

Weather-Normalized Load YoY Growth



Economic Forecast of Drivers that Influence Load

Driver or Indicator ⁽¹⁾	2012 Outlook
Gross Metro Product (GMP)	2012 GMP growth expected to increase to 2.0% from 0.7%
Employment	2012 Employment growth is expected to be 1.2%, slightly below 2011
Manufacturing	Challenged with weakness in pharmaceutical and oil refinery sectors, and energy efficiency initiatives
Households	2012 Household growth expected to increase to 0.4%, slightly above 2011
Energy Efficiency	Expected to reduce total 2012 load by ~0.7% per PAPUC filing

Expect weak economic outlook in 2012 to slightly offset energy efficiency

PECO Positioned for Continued Strong Financial Performance

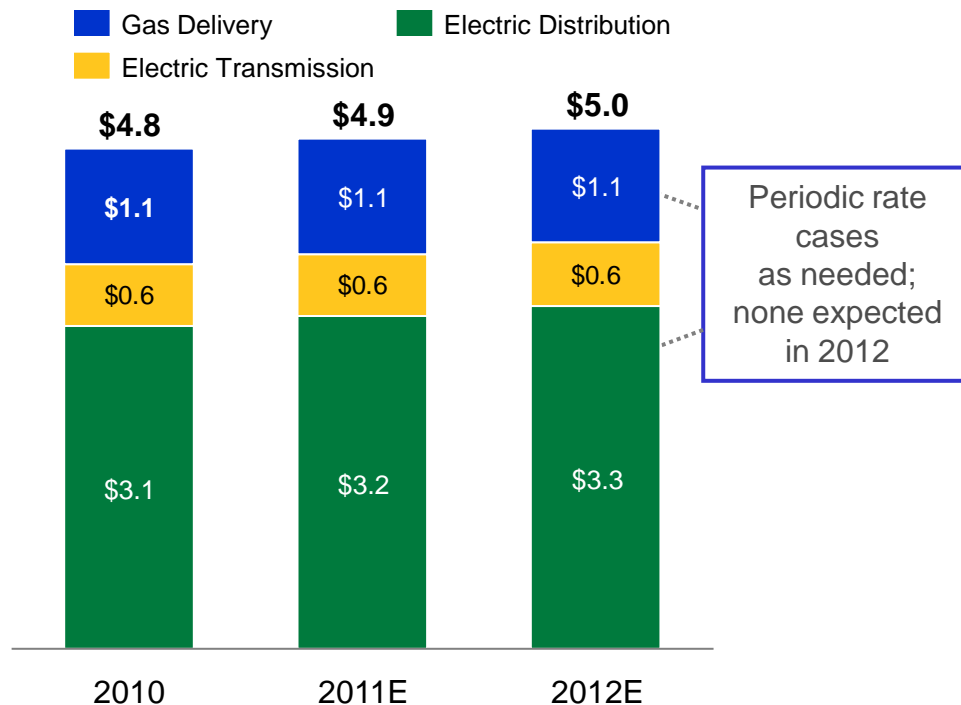
Recent Rate Cases

Electric Distribution ⁽¹⁾	Current Rates
Rates Effective	January 1, 2011
Test Year	2010
Revenue Increase	\$225 million

Gas Delivery ⁽¹⁾	Current Rates
Rates Effective	January 1, 2011
Test Year	2010
Revenue Increase	\$20 million

Electric Transmission	Stated rate; no recent rate cases
-----------------------	-----------------------------------

Rate Base in Rates End of Year Balance (\$ in billions)⁽²⁾



	2010A	2011E
Equity Ratio ⁽¹⁾	53%	55%
Earned ROE	11.8%	~13%
Ratemaking ROE ⁽³⁾	10%	~11%



Long-Term Target
53%
≥10%
≥10%

(1) PAPUC approved a joint settlement; no allowed return was specified.

(2) As determined for ratemaking purposes. Amounts reflect pro forma adjustments that may be made to determine rate base for rate case filing purposes.

(3) Reflects an average of electric distribution, transmission and gas.

PECO Procurement

PECO Procurement Plan ⁽¹⁾		Supply Procurement RFPs to Date Full Requirements Average Price – \$/MWh ⁽²⁾					
Customer Class	Products	June 2009	Sept 2009	May 2010	Sept 2010	May 2011	Sept 2011
Residential	<ul style="list-style-type: none"> 75% full requirements 20% block energy 5% energy only spot 	\$88.61	\$79.96	\$69.38	\$66.83	-	\$76.27
Small Commercial (peak demand <100 kW)	<ul style="list-style-type: none"> 90% full requirements 10% full requirements spot 	-	\$85.43	\$72.47	\$70.82	-	\$77.71
Medium Commercial (peak demand >100 kW but ≤ 500 kW)	<ul style="list-style-type: none"> 85% full requirements 15% full requirements spot 	-	\$86.70	\$74.59	\$70.36	-	\$74.13
Large C&I (peak demand >500 kW)	<ul style="list-style-type: none"> Fixed-priced full requirements Hourly full requirements⁽³⁾ 	-	-	-	Large Hourly: \$4.83 ⁽³⁾	Large Hourly: \$4.97 ⁽³⁾	-

Six supply procurements completed; three procurements scheduled in 2012

(1) See PECO Procurement website (<http://www.pecoprocurement.com>) for additional details regarding PECO's procurement plan and RFP results.

(2) Wholesale prices. No Small/Medium Commercial products were procured in the June 2009 and May 2011 RFP.

(3) Large Hourly price includes only ancillary services, supplier-provided Alternative Energy Portfolio Standard (AEPS) and miscellaneous costs.