



Clean in Competitive Markets

Investor Meetings

December 2010



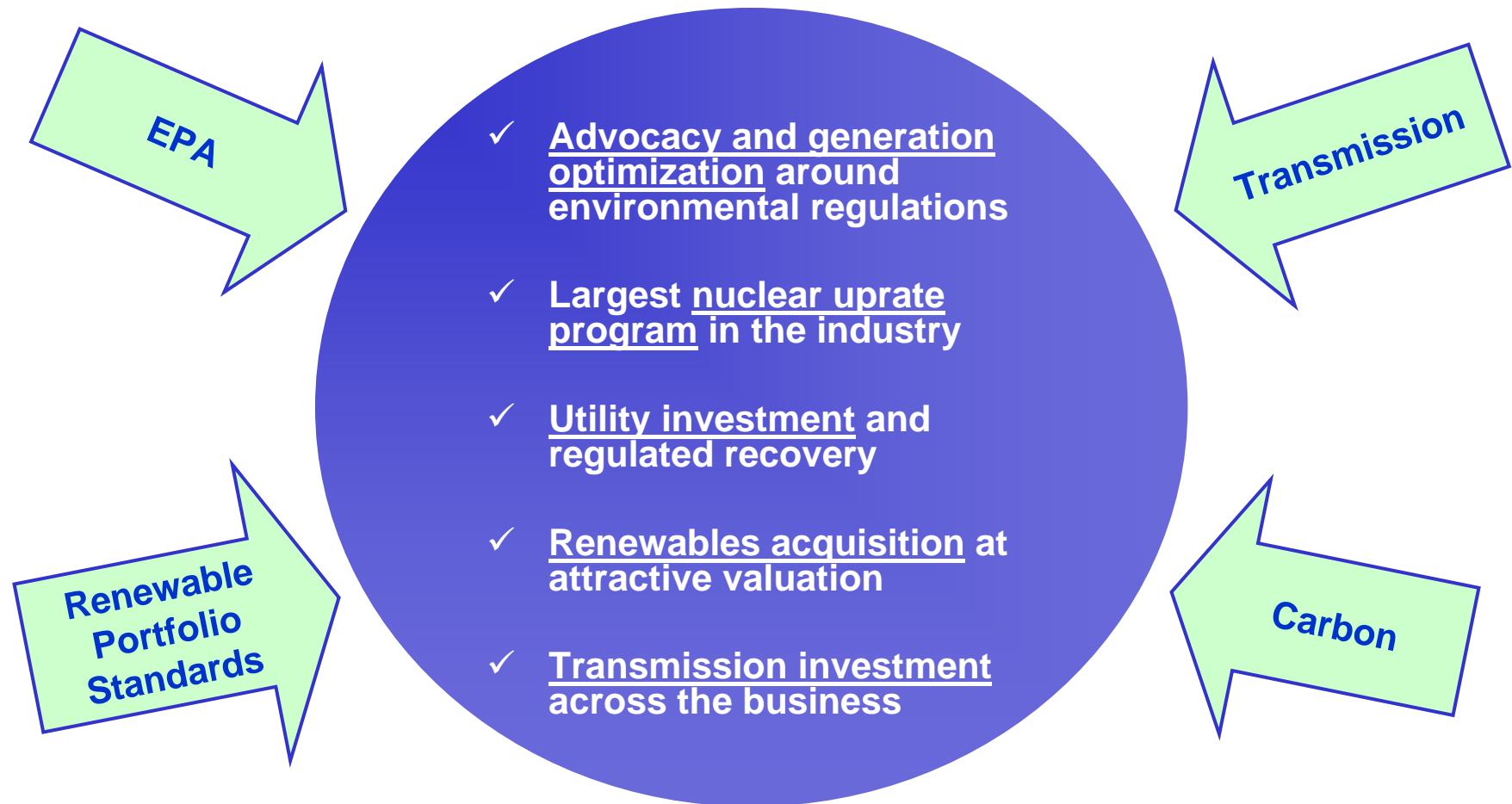
Forward-Looking Statements



This presentation includes 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 these forward-looking statements include those discussed herein as well as those discussed in (1) Exelon's 2009 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 Third Quarter 2010 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 13 and (3) other factors discussed in filings with the Securities and Exchange Commission (SEC) by Exelon Corporation, Commonwealth Edison Company, PECO Energy Company and Exelon Generation Company, LLC (Companies). 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 Companies undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

This presentation includes references to adjusted (non-GAAP) operating earnings and non-GAAP cash flows that exclude the impact of certain factors. We believe that these adjusted operating earnings and cash flows are representative of the underlying operational results of the Companies. Please refer to the appendix to this presentation for a reconciliation of adjusted (non-GAAP) operating earnings to GAAP earnings. Please refer to the footnotes of the following slides for a reconciliation non-GAAP cash flows to GAAP cash flows.

Exelon's Protect and Grow strategy considers existing and potential energy policy to create long-term value



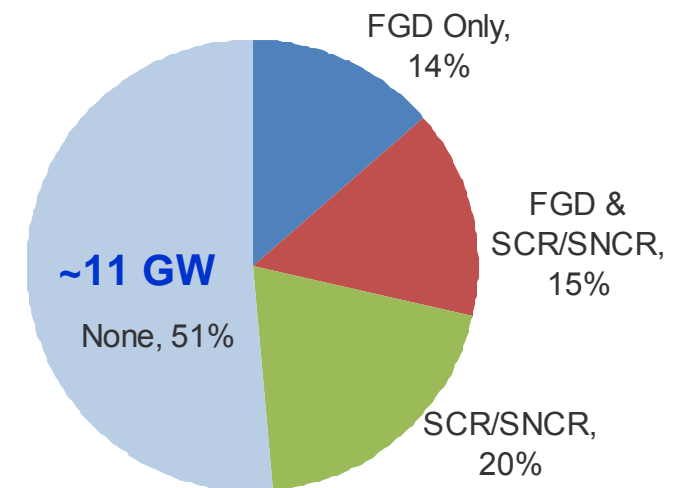
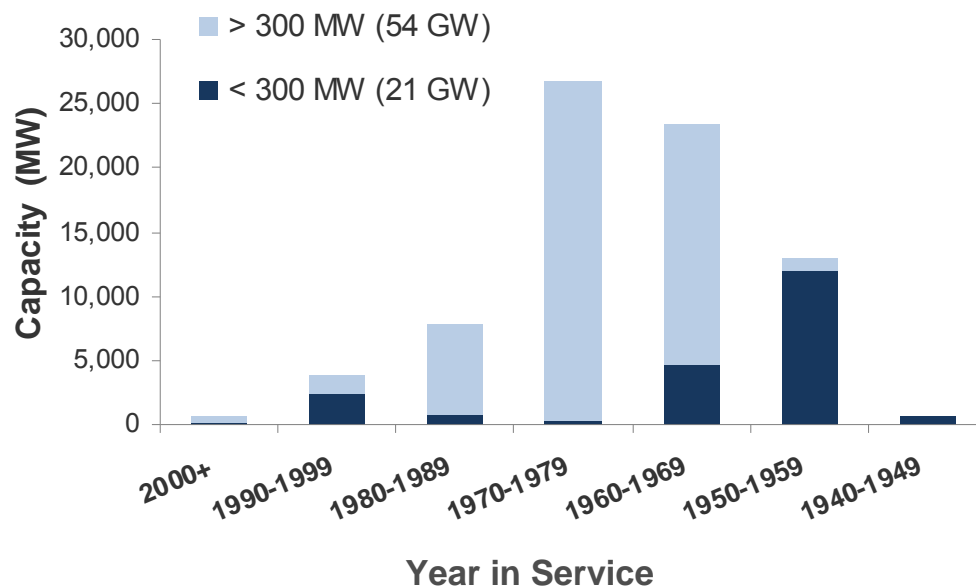
Exelon 2020 identifies the most rational economic options to deliver shareholder value as energy policy turns toward clean energy and affects competitive markets

Older, smaller coal units are likely to retire as EPA implementation dates approach



PJM Coal Capacity by Age 75 GW Total

Environmental Controls on PJM units < 300 MW ⁽¹⁾

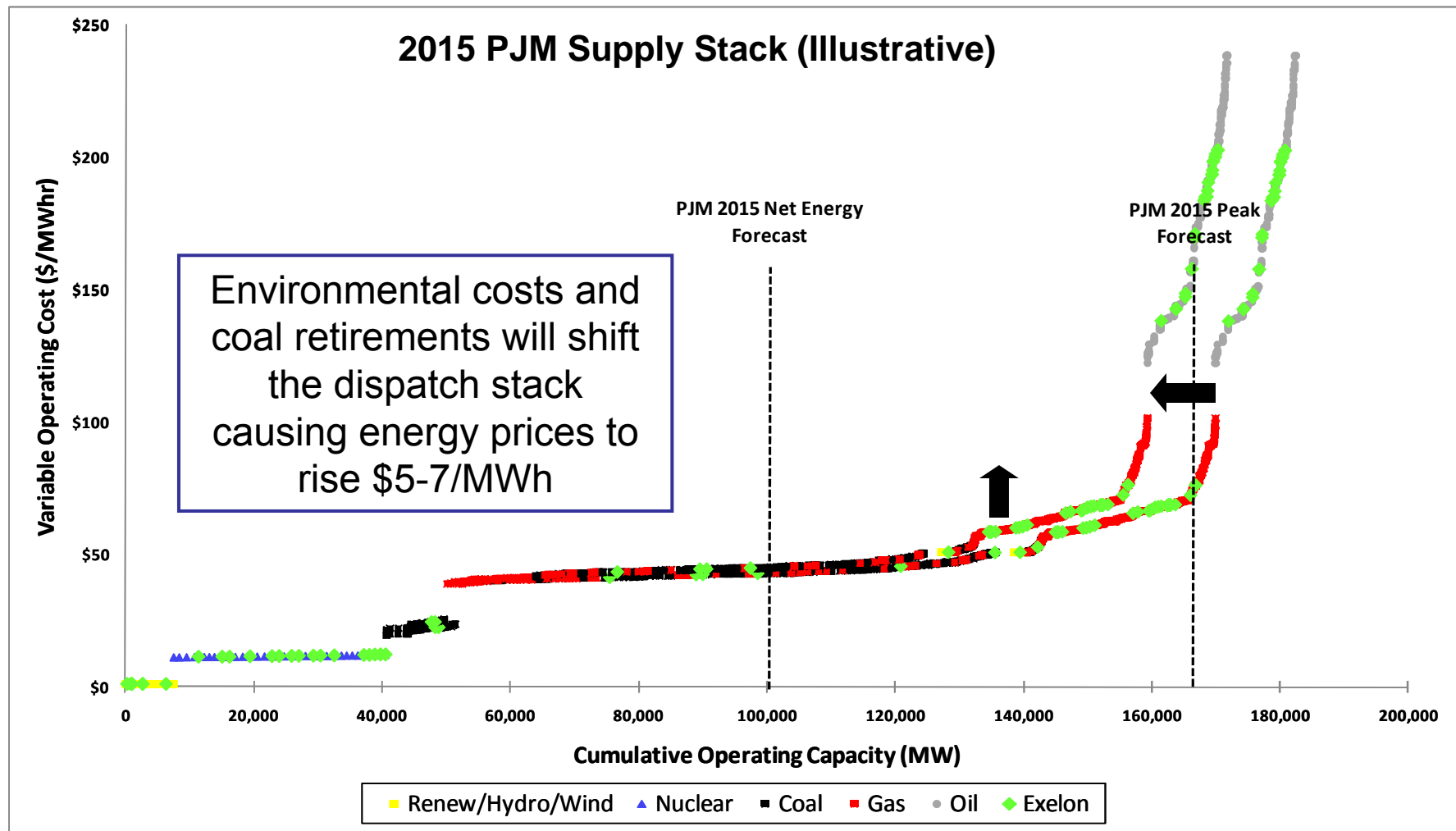


EPA regulations make retirement economically rational for approximately 11 GW of PJM coal plants, beginning the transition to clean energy

(1) Includes flue gas desulfurization (FGD), selective catalytic reduction (SCR), and selective noncatalytic reduction (SNCR); status will vary based on data source.

Sources: Energy Velocity, Exelon estimates

A shift in the PJM dispatch stack as coal retires benefits Exelon's clean nuclear fleet

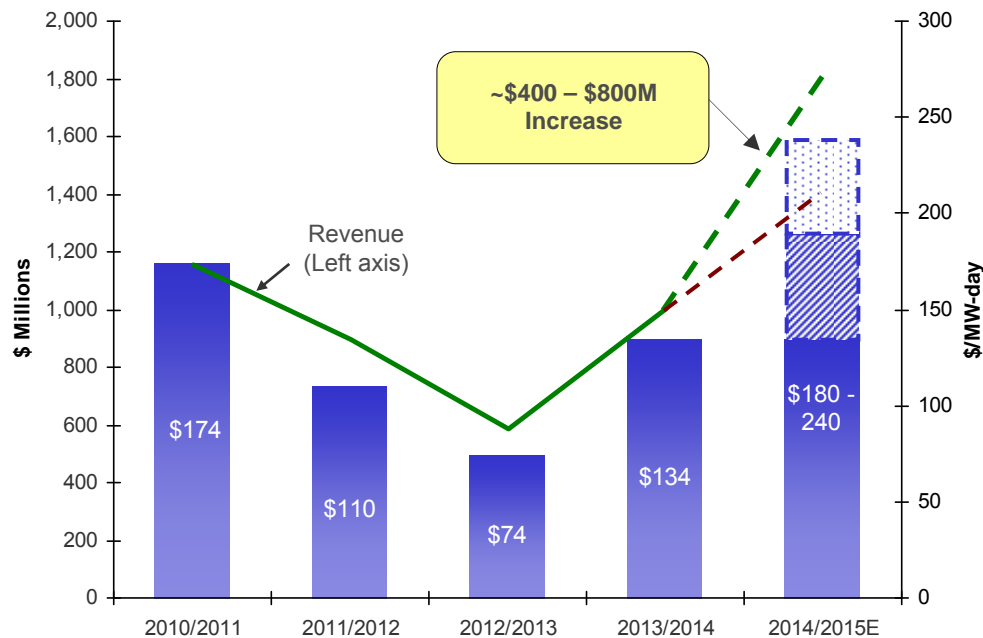


Sources: CEMS, Energy Velocity, SNL, Exelon estimates
Note: PJM Supply Stack based on existing capacity and expected retirements.

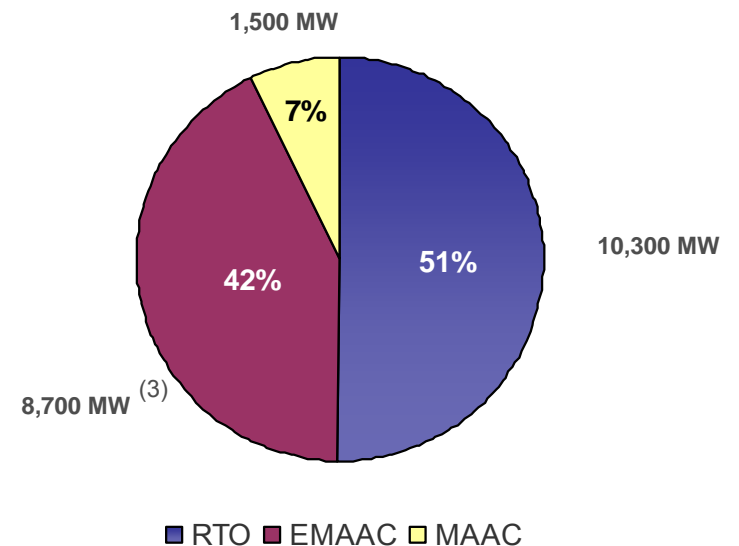
PJM capacity auction will also send market price signals to incent new, clean generation



PJM RPM Capacity Prices and Revenues ⁽¹⁾



Capacity by Region Eligible for 2014/15 RPM Base Residual Auction ⁽²⁾



While results are largely dependent on bidding behavior, Exelon expects increasing capacity prices beginning in the 2014/15 planning year as coal generators evaluate environmental compliance costs

(1) Weighted average \$/MW-Day would apply if all owned generation cleared. Prices are rounded.

(2) All generation values are approximate and not inclusive of wholesale transactions; All capacity values are in installed capacity terms (summer ratings) located in the areas and adjusted for mid year PPA roll offs. John Deere Renewables capacity is not included.

(3) Reflects decision in December 2009 to permanently retire Cromby Station and Eddystone Units 1&2 as of 5/31/11. None of these 933 MW cleared in the 2011/2012 or 2012/2013 auctions.

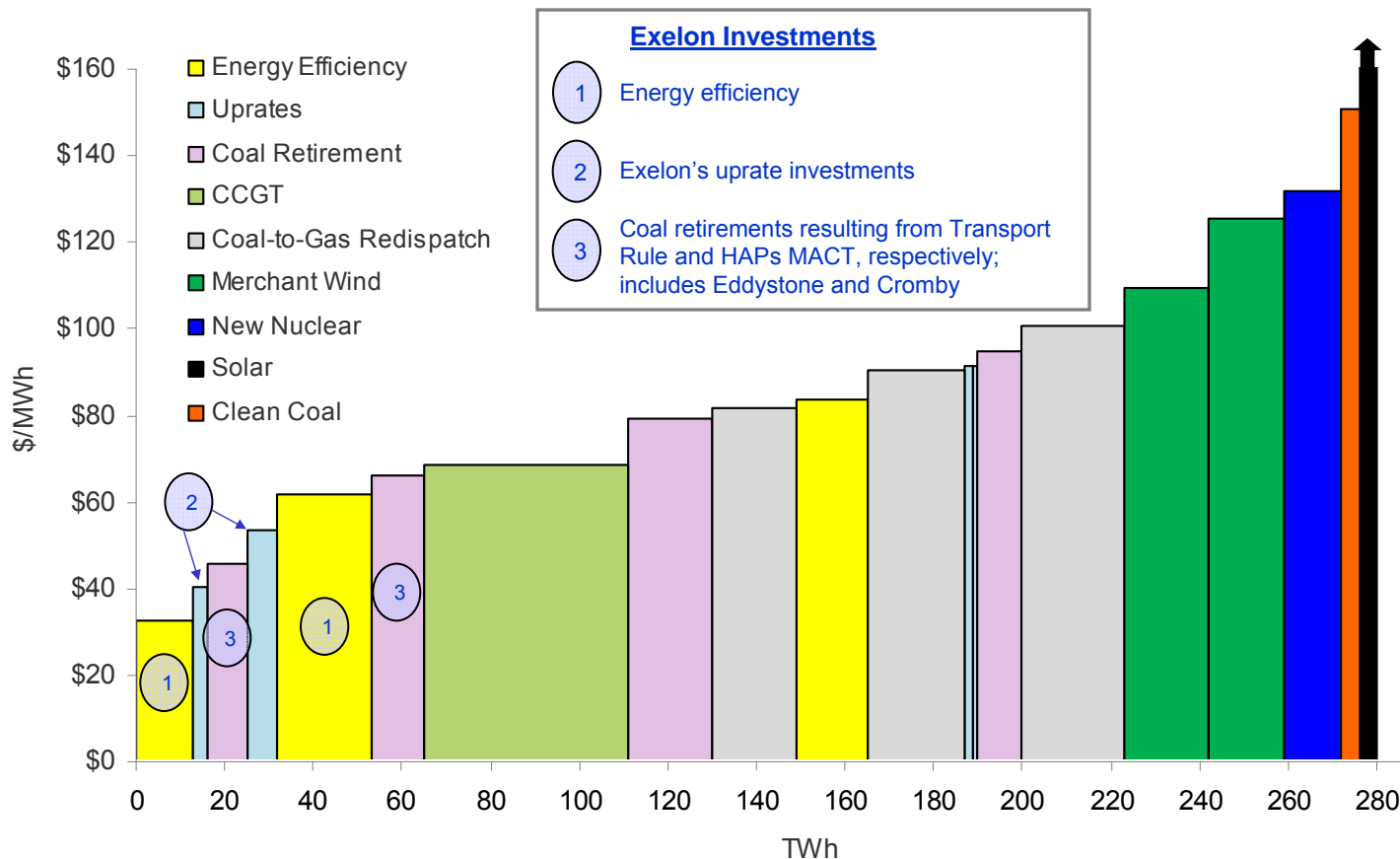
RPM = Reliability Pricing Model, RTO = Regional Transmission Organization (i.e. Rest of Pool), MAAC = Mid-Atlantic Area Council, EMAAC = Eastern Mid-Atlantic Area Council

Note: Data contained on this slide is rounded.

Exelon 2020 Supply Curve shows how PJM can clean the dispatch stack



Post-MACT Real Required ATC Price (Energy + Capacity)



➤ Supply Curve shows the increasing energy and capacity prices needed to make clean energy investments economic

➤ Exelon is focused on the lowest cost alternatives

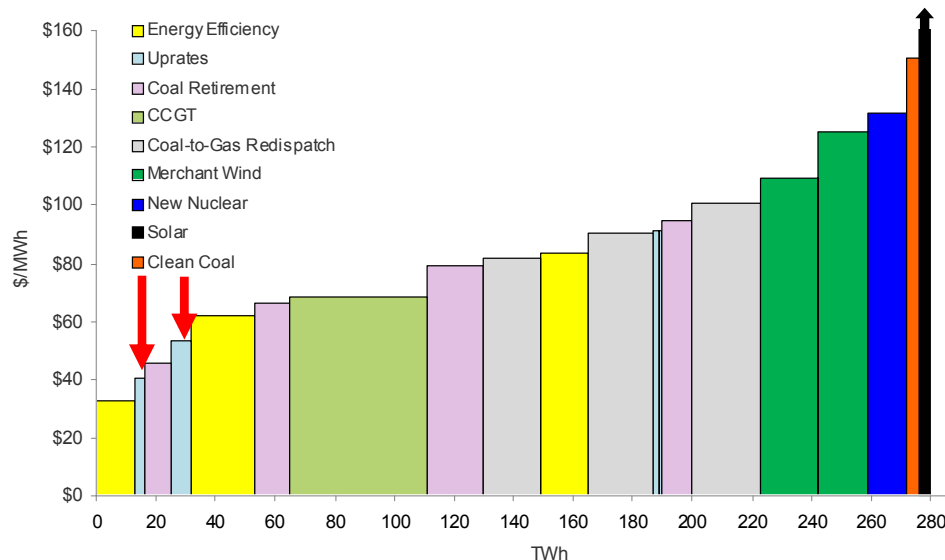
The supply curve is guiding Exelon's strategy and investment decisions, including nuclear uprates, energy efficiency and coal retirements

Note: Represents a single economic and power market outlook, which is indicative of a range of scenarios. See slide 40 for additional details.
CCGT = Combined Cycle Gas Turbine, HAPs MACT = Hazardous Air Pollutant Maximum Achievable Control Technology as designated by the EPA.

Exelon's nuclear uprate program is one of the most economically attractive ways to add clean generation in PJM



Post-MACT Real Required ATC Price (Energy + Capacity)



Year	Uprate MWs to be brought on line (cumulative) ⁽¹⁾
2011	200
2012	325
2013	405
2014	430
2015-17	1,300 – 1,500

- **Unique:** Size and scale of nuclear fleet is a competitive advantage
- **Economic:** IRRs meet hurdle rate under a number of gas and power price scenarios
- **Flexible:** A series of 19 separate projects across all but 1 of our nuclear plants
- **Low Risk:** Not contingent on loan guarantees to merchant plants
- **Earnings Accretive:** For EPU's only, annual EPS impact of \$0.30 - \$0.50 per share once all MW online

Exelon's nuclear uprates are another example in Exelon's long history of effective capital stewardship

(1) Includes TMI and Clinton Extended Power Uprates, which are currently under review.

ComEd and PECO play a key role in support of clean, competitive markets



Investing in Transmission

➤ West Loop Phase II – supporting reliability

- Ensures reliable service to the Chicago Central Business District in the event that Fisk and Crawford stations ⁽¹⁾ become unavailable
- Estimated cost of \$178M
- Late 2011 expected in-service date
- Immediate benefits including redundancy

➤ Upgrades related to ExGen's Cromby and Eddystone retirements ⁽²⁾ – ensuring reliability of the grid

- Facilities identified and plans approved by PJM
- Total estimated cost of \$44M
- All projects under construction or in engineering status

Investing in New Technologies

➤ Electric Vehicles – exploring opportunities for infrastructure investment

- ~\$3M in Federal stimulus funds to expand green fleet
- Deploy vehicle smart charging stations
- Study vehicle performance, environmental and electrical load effects

➤ Smart Grid – delivering customer-valued services

- ~\$200M in Federal stimulus funds for deployment
- Operational improvements and efficiency gains will allow continued cost savings
- Programs will enable customers more control over usage and rate structures

Our utilities are advancing regulatory recovery for Smart Grid investments and investing in system improvements to protect and grow value

(1) Crawford and Fisk generating stations are owned and operated by Midwest Generation, a subsidiary of Edison International.

(2) Cromby Units 1 and 2 to retire effective 5/31/11 and 12/31/11, respectively. Eddystone Units 1 and 2 to retire effective 5/31/11 and 6/01/12, respectively.

Acquisition of John Deere Renewables (JDR) positions Exelon as a key player in the US wind market



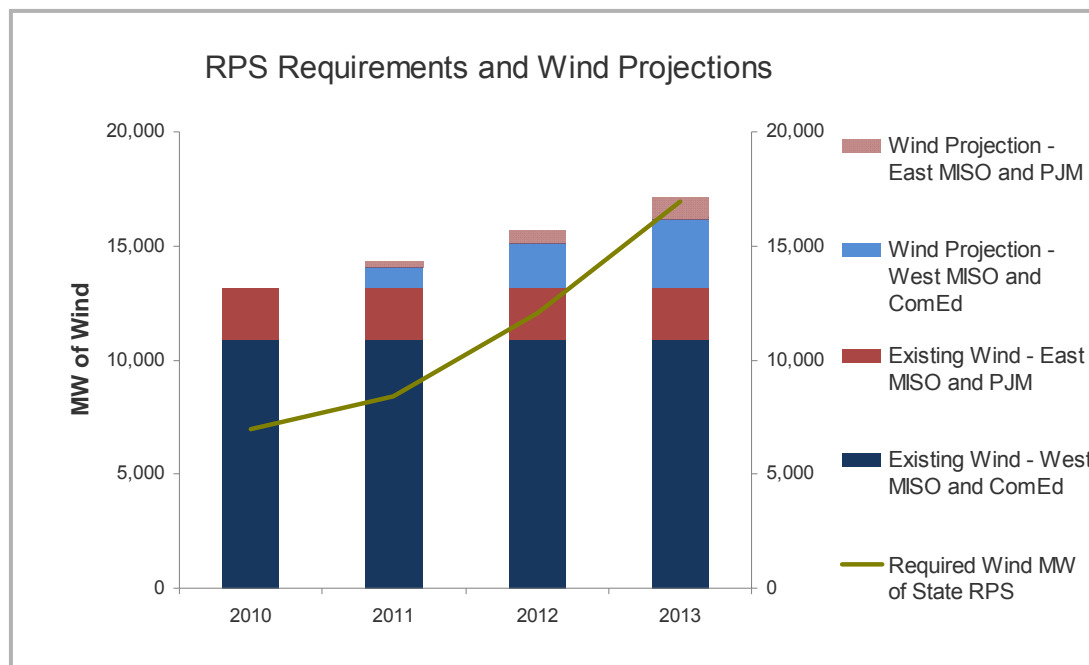
JDR Acquisition Key Dates:

Texas regulatory approval filed 9/17

FERC/HSR approval filed 9/30

Financing completed 9/30

Projected closing December 2010

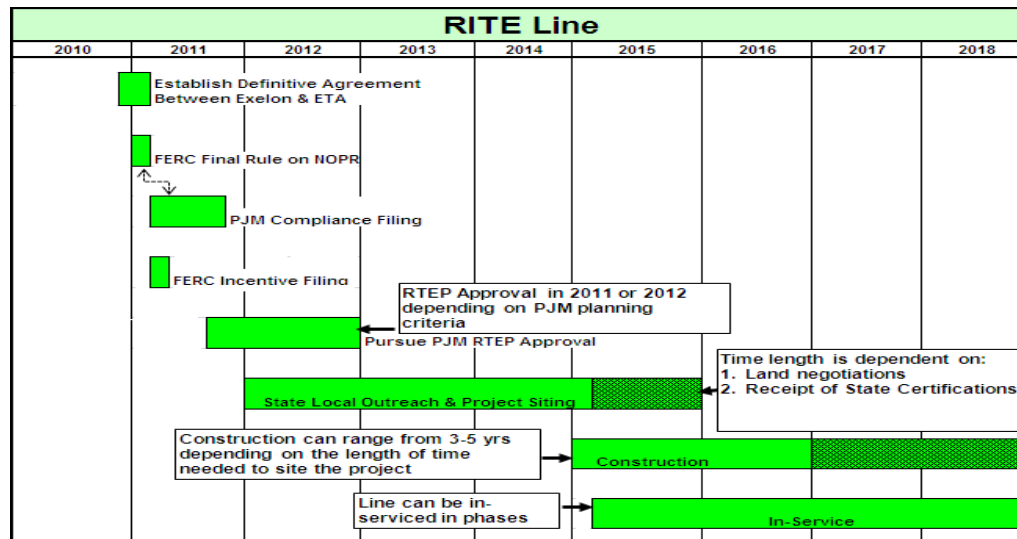
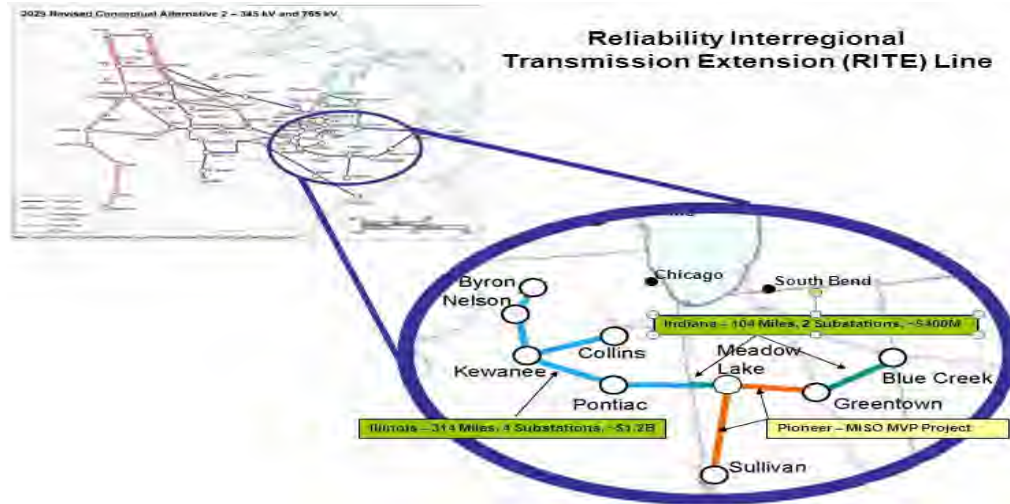


- \$150M/year EBITDA run-rate from JDR ⁽¹⁾
- Only moderate wind growth expected through 2013
 - Additional 4 GW in PJM and MISO from 2011-13
 - Renewable Portfolio Standards (RPS) are met through 2013
- Incremental development largely dependent on transmission and cost allocation
- Federal RPS could accelerate transmission development decisions

Exelon's future development of our wind pipeline will be compatible with the price signals of the Exelon 2020 supply curve and will require PPAs to be in place

(1) Including Production Tax Credits and Michigan development projects.

Exelon is pursuing backbone high-voltage transmission investment in the Midwest



- First anchor project from the SMARTtransmission Study
- Memorandum of Understanding signed with ETA (AEP & MidAmerican joint venture company) to pursue the project
- ~420 miles of 765kV transmission stretches from Northern Illinois to Ohio. The RITE Line will be built from the existing 765kV system in Ohio in the East to the West
- Ensures reliability, enables states to meet RPS standards, and supports the integration of more renewables
- Total Investment ~\$1.6 billion
 - ComEd/Exelon ~\$1.1 billion
 - AEP/ETA ~\$500 million
- FERC incentive rate joint filing anticipated for 1Q 2011

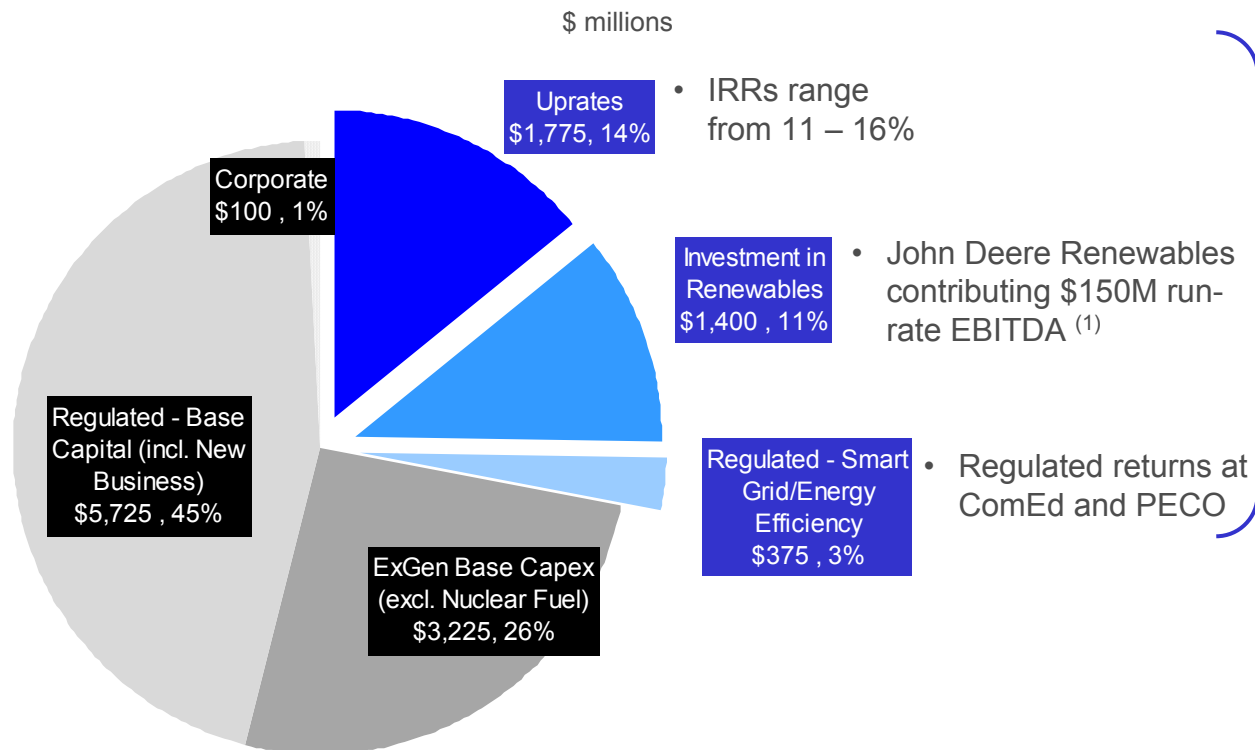
Note: ETA = Electric Transmission America

Transmission investment via the “RITE Line” creates value for Exelon and supports further clean energy development

Exelon's investments in clean energy and competitive markets create value



2010 – 2013 Exelon Investment



Nearly 30% of total non-fuel capital expenditures supports our goal of being clean in competitive markets

When combined with proactive efforts to inform and shape policy, Exelon has allocated resources to the areas where its long-term value is maximized

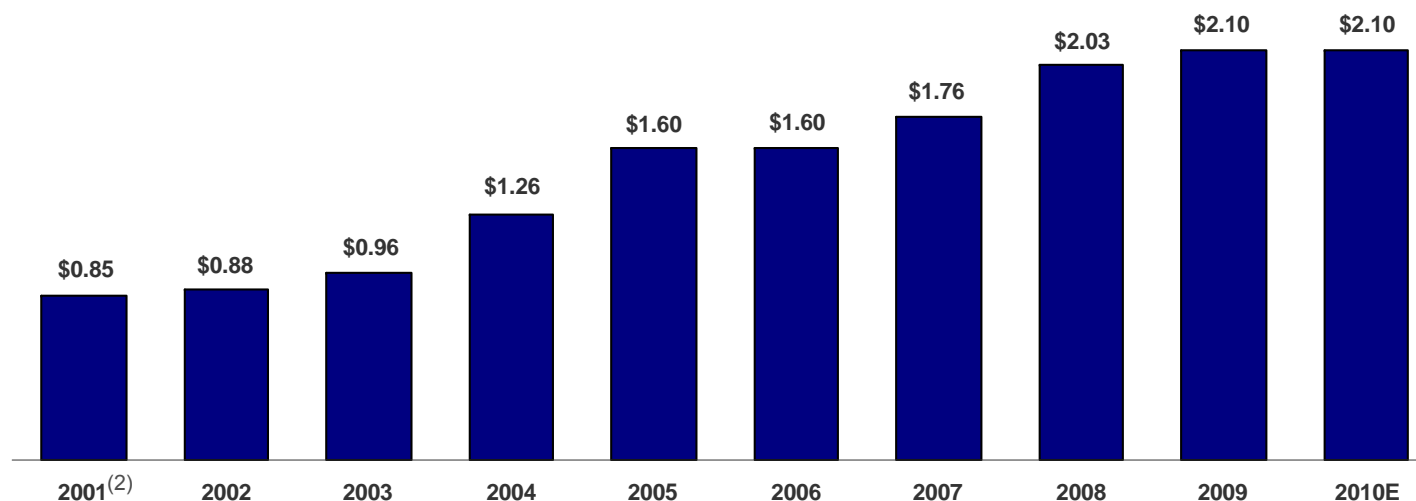
(1) Including Production Tax Credits and Michigan development projects.

Note: Uprates excludes TMI and Clinton Extended Power Uprates, which are under review. Investment in Renewables includes \$900 million acquisition of John Deere Renewables, which is expected to close in 4Q10, and related development capital expenditures.

Strong, stable dividend remains a key component of shareholder value return



Historical CAGR (2001-2010) ~10%



Dividend Yield ⁽¹⁾

Exelon: 5.1%

Competitive Integrated: 4.4%

Regulated Integrated: 4.6%

Exelon currently offers one of the highest yields among its peers

Note: CAGR= Compound Annual Growth Rate. Chart represents dividends per share paid by Exelon for 2001-2009 and expected dividend for 2010, which is subject to Board approval.

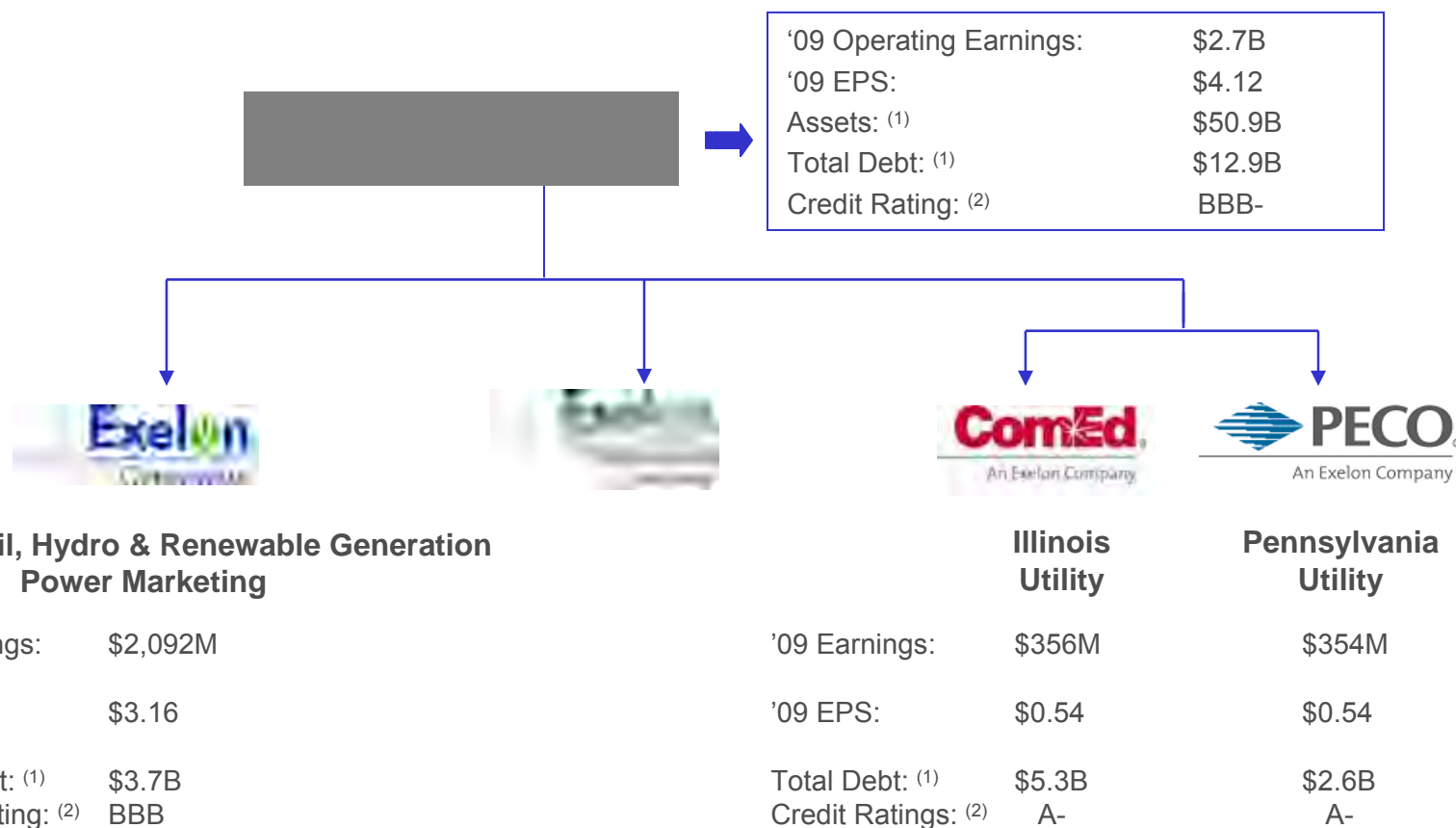
(1) Dividend yield as of October 25, 2010. Competitive Integrated Yield average includes AYE, CEG, EIX, ETR, FE, NEE, PPL, and PEG. Regulated Integrated Yield average includes AEP, AEE, D, DTE, DUK, PCG, PGN, SO, WEC, and XEL.

(2) 2001 dividend excludes \$0.065 per share pro-rata dividend related to the Unicom-PECO merger.



Financial and Operating Data

The Exelon Companies



Note: All '09 income numbers represent adjusted (Non-GAAP) Operating Earnings and EPS. Refer to slide 91 for reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS.

(1) As of September 30, 2010.

(2) Standard & Poor's senior unsecured debt ratings for Exelon and Generation and senior secured debt ratings for ComEd and PECO as of October 26, 2010.

Multi-Regional, Diverse Company



An Exelon Company



An Exelon Company

Electricity Customers: 3.8M

Electricity Customers: 1.6M

Gas Customers: 0.5M

Total Capacity

Owned: 24,850 MW
Contracted: 6,153 MW
Total: 31,003 MW

New England Capacity

Owned: 182 MW

Mid-Atlantic Capacity

Owned: 11,034 MW
Contracted: 336 MW
Total: 11,370 MW

Midwest Capacity

Owned: 11,412 MW
Contracted: 2,900 MW
Total: 14,312 MW

ERCOT/South Capacity

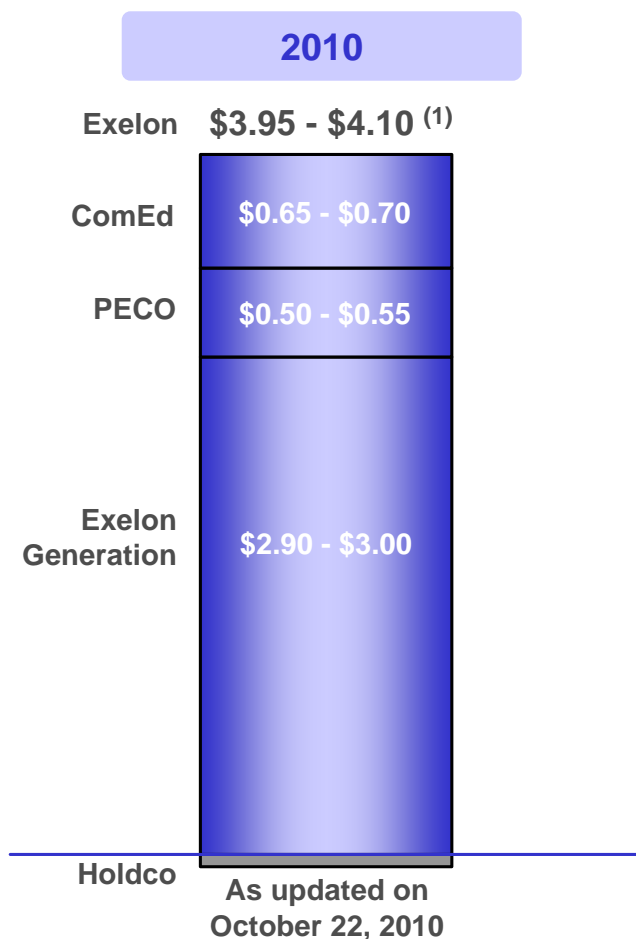
Owned: 2,222 MW
Contracted: 2,917 MW
Total: 5,139 MW

Generating Plants

Nuclear ▲
Hydro ◆
Coal ●
Gas/Oil Intermediate ■
Peakers ★
Wind ×
Solar/Methane +

Note: Owned megawatts as of December 31, 2009 based on Generation's ownership, using annual mean ratings for nuclear units (excluding Salem) and summer ratings for Salem and the fossil and hydro units. Does not include megawatts from acquisition of John Deere Renewables announced on August 31, 2010.

Operating Earnings Guidance



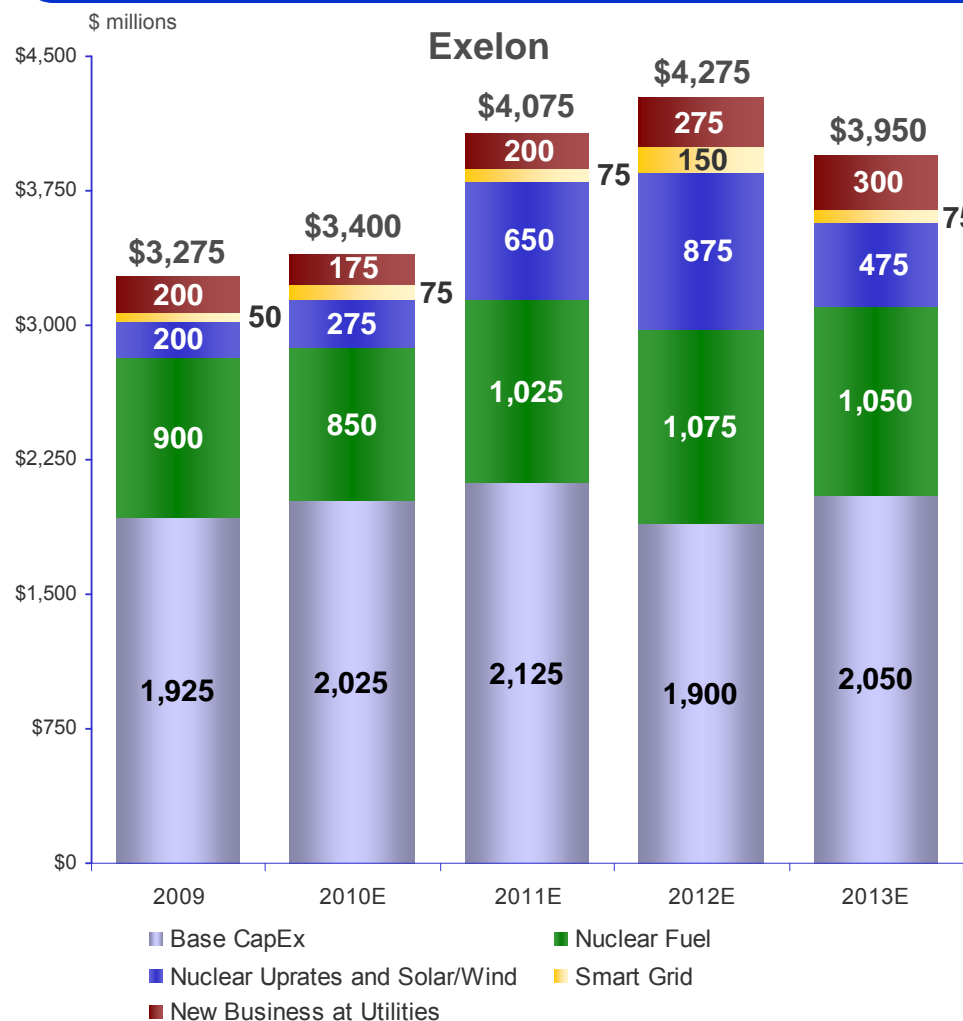
Guidance to be provided in early 2011, which will include:

- Operating EPS – Consolidated and by Operating Company
- Key earnings drivers
- O&M guidance, including pension and OPEB expense
- Cash flow and credit metrics outlook
- Load forecast for ComEd and PECO service territories

After the third quarter, we revised 2010 operating earnings guidance to \$3.95-\$4.10/share ⁽¹⁾; 2011 guidance to be provided in early 2011

(1) We raised 2010 earnings guidance on October 22, 2010, and we are not updating earnings guidance at this time. Earnings guidance is only reviewed in connection with our quarterly earnings announcements or if we expressly indicate that we are updating the guidance. Refer to slide 92 for adjustments of (non-GAAP) operating EPS to GAAP EPS.

Capital Expenditures Expectations



	2009	2010E	2011E	2012E	2013E
Exelon Generation					
Base CapEx	875	800	825	800	800
Nuclear Fuel ⁽¹⁾	900	850	1,025	1,075	1,050
Nuclear Upgrades ⁽²⁾	150	275	475	550	475
Solar / Wind ⁽³⁾	50	-	175	325	-
Total ExGen	1,975	1,925	2,500	2,750	2,325
ComEd					
Base CapEx	650	775	850	650	800
Smart Grid/Meter ⁽⁴⁾	50	50	25	100	25
New Business	150	125	125	200	225
Total ComEd	850	950	1,000	950	1,050
PECO					
Base CapEx	350	425	425	425	425
Smart Grid/Meter	-	25	50	50	50
New Business	50	50	75	75	75
Total PECO	400	500	550	550	550
Corporate					
	50	25	25	25	25

(1) Nuclear fuel shown at ownership, including Salem.

(2) Excludes TMI and Clinton EPU's, which are under review.

(3) Does not include \$900 million related to acquisition of John Deere Renewables.

(4) ComEd does not plan to move forward with these Smart Grid/Meter investments unless appropriate cost recovery mechanisms are in place.

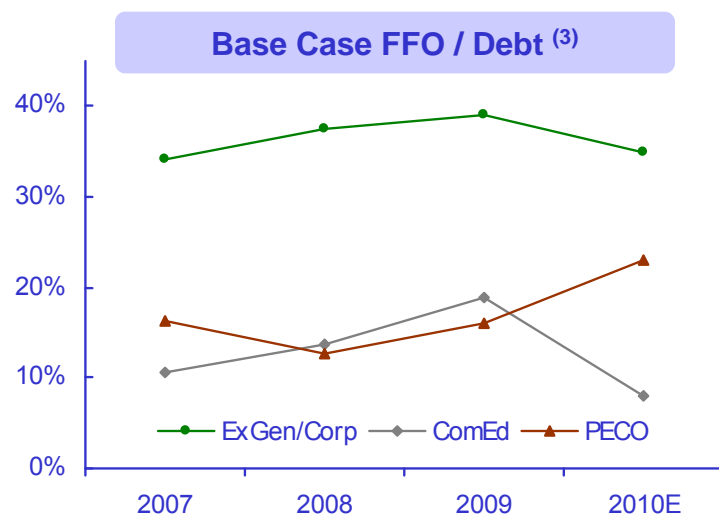
Note: Capital investment related to RITE Transmission Line is not included.

Note: Data contained on this slide is rounded.



Credit Metric Outlook

- Financing plans, including incremental debt, designed to maintain credit metrics and investment grade rating, while funding growth projects and meeting future obligations, including uprates, dividend, and pension
- Evaluated under a variety of economic scenarios, including a low gas stress case environment
- Evaluate the credit of each company on a stand-alone basis



Company	FFO/Debt Target Range ⁽¹⁾
ExGen/Corp ⁽²⁾	30-35%
ComEd	15-18%
PECO	15-18%

ExGen/Corp FFO/Debt credit metrics are expected to be within target range through 2013 without an equity issuance, based on 9/30 forward prices

- (1) See slide 28 for FFO/Debt reconciliations to GAAP. FFO/Debt metrics include the following standard adjustments: debt equivalents for PV of Operating Leases, PPAs, unfunded Pension and OPEB obligations (after-tax) and other minor debt equivalents. Debt is imputed for estimated pension and OPEB obligations by operating company.
- (2) FFO/Debt Target Range reflects Generation FFO/Debt in addition to the debt obligations of Exelon Corp.
- (3) Reflects impacts of preliminary agreement with IRS to settle involuntary conversion and Competitive Transition Charge (CTC) positions (\$420M) at ComEd. Expected to return to target levels in 2011. For additional information see "Other Income Tax Matters" under Footnote 10 of the Q3 2010 Form 10-Q.

Projected 2010 Key Credit Measures



		With PPA & Pension / OPEB ⁽¹⁾	Without PPA & Pension / OPEB ⁽²⁾	Moody's Credit Ratings ⁽³⁾	S&P Credit Ratings ⁽³⁾	Fitch Credit Ratings ⁽³⁾
Exelon Consolidated:	FFO / Interest	5.9x	6.2x	Baa1	BBB-	BBB+
	FFO / Debt	23%	32%			
	Rating Agency Debt Ratio	59%	48%			
ComEd:	FFO / Interest	2.4x	2.0x	Baa1	A-	BBB+
	FFO / Debt	8% ⁽⁴⁾	7% ⁽⁴⁾			
	Rating Agency Debt Ratio	52%	43%			
PECO:	FFO / Interest	5.1x	4.6x	A1	A-	A
	FFO / Debt	23%	25%			
	Rating Agency Debt Ratio	50%	47%			
Generation:	FFO / Interest	11.7x	21.3x	A3	BBB	BBB+
	FFO / Debt	43%	85%			
	Rating Agency Debt Ratio	48%	31%			
Generation / Corp:	FFO / Interest	9.5x	14.2x			
	FFO / Debt	35%	62%			
	Rating Agency Debt Ratio	69%	54%			

Notes: Exelon and PECO metrics exclude securitization debt. See slide 28 for FFO (Funds from Operations)/Interest, FFO/Debt and Adjusted Book Debt Ratio reconciliations to GAAP.

(1) FFO/Debt metrics include the following standard adjustments: debt equivalents for PV of Operating Leases, PPAs, unfunded Pension and OPEB obligations (after-tax) and other minor debt equivalents.

(2) Excludes items listed in note (1) above.

(3) Current senior unsecured ratings for Exelon and Exelon Generation and senior secured ratings for ComEd and PECO as of October 26, 2010.

(4) Reflects impacts of preliminary agreement with IRS to settle involuntary conversion and CTC positions (\$420M). Expected to return to target levels in 2011. For additional information see "Other Income Tax Matters" under Footnote 10 of the Q3 2010 Form 10-Q.



Committed to Investment Grade Ratings

Exelon believes that solid investment grade ratings are critical for managing and operating both regulated utilities and a commodity-based generation company

Commercial Business Opportunities

- Asset acquisitions
- Ability to participate in or to bid competitively for PPAs and long-term transactions
- Increased liquidity for energy trading: counterparties' costs would increase for non-investment grade transactions, thereby reducing market participation

Manageable Liquidity Requirements

- Lower collateral requirements for energy trading
- Ability to secure sizeable and sufficient bank credit facilities (currently \$7.4B)
- Use of guarantees (versus letters of credit) to fulfill NRC requirements for Nuclear Decommissioning Trust obligations

Efficient Capital Markets Access

- Reliable access to long-term debt markets to meet sizeable capital program
- Lower cost and ability to extend debt maturity profile
- Access to commercial paper market

Business and Financial Flexibility




- Avoid prepayments on long-term contracts (such as uranium), which reduce working capital requirements
- Avoid restrictive bond covenants and secured financing transactions
- Limits regulatory friction

Our investment grade rating increases the pool of lenders, provides access to a broad range of trading counterparties, and enhances our strategic options

Sufficient Liquidity



Available Capacity Under Bank Facilities as of October 25, 2010

(\$ millions)	 An Exelon Company	 An Exelon Company	 An Exelon Company	Exelon ⁽³⁾
Aggregate Bank Commitments ⁽¹⁾	\$1,000	\$574	\$4,834	\$7,365
Outstanding Facility Draws	--	--	--	--
Outstanding Letters of Credit	(196)	(1)	(226)	(430)
Available Capacity Under Facilities ⁽²⁾	804	573	4,608	6,935
Outstanding Commercial Paper	--	--	--	--
Available Capacity Less Outstanding Commercial Paper	\$804	\$573	\$4,608	\$6,935

Exelon bank facilities are largely untapped

(1) Excludes previous commitment from Lehman Brothers Bank and commitments from Exelon's Community and Minority Bank Credit Facility.

(2) Available Capacity Under Facilities represents the unused bank 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 other corporate entities.

Credit Facility Plans



- Exelon's primary sources of short-term liquidity include credit facilities, commercial paper, the money pool ⁽¹⁾ and cash on hand
- Current total credit facility size is \$7.4 billion, the largest in the power sector
- Large and diverse bank group – 23 banks committed to the facilities with each bank having less than 10% of the aggregate commitments

Exelon Corp + Exelon Generation

- \$5.8 billion facilities largely expire October 26, 2012 - plan to extend/refinance the facilities in first half of 2011
- Continued use of non-margining transactions and currently evaluating alternatives to reduce reliance on bank credit

PECO

- \$574 million facility largely expires on October 26, 2012 - plan to extend/refinance the facility in first half of 2011

ComEd

- Successfully executed \$1 billion revolving credit facility agreement which will expire on March 25, 2013
 - Replaces previous \$952 million facility that was due to expire on 2/16/11
 - Reflects strong relationships with large, diverse bank group
 - 22 banks in facility – none with exposure of more than 6%
-
- Recently closed on a \$94 million 364-day credit facility with a group of 29 community and minority-owned banks

Bank market continues to improve and facility costs are tightening

(1) ComEd does not participate in the money pool.

Pension and OPEB Funding



Pension Framework

- Pension Protection Act of 2006 ("PPA 2006") generally requires funding of qualified pension plans over a seven year period; OPEB plans do not have a required funding level ⁽¹⁾
- Pension unfunded amounts are imputed as debt by S&P and Moody's in the FFO/Debt calculation; S&P also imputes debt for OPEB

Exelon's Position

- Exelon's estimated pension contributions include the minimum amount required under ERISA, including amounts necessary to avoid benefit restrictions and at-risk status as defined by PPA 2006 ⁽²⁾
- OPEB contributions are based on various factors, including tax deductibility and levels of benefit claims
- Plan to fund obligations with combination of cash and debt

As of 9/30/10 (\$ millions)	Pension	OPEB
Unfunded Status	\$4,460	\$2,736
Sensitivities to a 50 basis point change ⁽³⁾		
Discount rate (cost / obligation)	\$85 / \$950	\$30 / \$250
EROA (cost) ⁽⁴⁾	\$45	\$5

Exelon monitors economic conditions, funding election options, and pension funding relief to ensure efficient funding policies are employed

(1) PECO is subject to certain contribution requirements established by the PAPUC.

(2) PPA 2006 requires attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits) and at-risk status (which triggers higher minimum contribution requirements and participant notification).

(3) Sensitivities are averages meant to provide directional guidance and are not necessarily symmetrical for increases and decreases in rates. Cost sensitivities shown include ~25% overall capitalization of pension costs.

(4) EROA = Expected return on assets; represents impact on cost. The expected return on assets assumption for pension is 8% and 7.37% for OPEB for 2011 and 2012.

Potential Variability in Future Pension Expense and Contributions



Illustrative Scenario (\$ in millions)	Assumptions		2011		2012	
	Asset Return Experience	Discount Rate	Pre-tax expense	Expected contribution	Pre-tax expense	Expected contribution
Baseline as of September 30, 2010	4.00% in 2010	5.83% in 2010	\$350	\$910	\$320	\$900
	8.00% in 2011	5.01% in 2011				
	8.00% in 2012	5.15% in 2012				
<i>Unfunded balance – end of year</i>				\$3,800		\$2,870
Alternative I	4.00% in 2010	5.83% in 2010	\$305	\$735	\$220	\$835
Mild Stagflation	7.60% in 2011	5.38% in 2011				
	5.22% in 2012	6.40% in 2012				
<i>Unfunded balance – end of year</i>				\$2,180		\$1,120
Alternative II	4.00% in 2010	5.83% in 2010	\$450	\$1,235	\$355	\$1,330
V-Shaped Recovery	8.00% in 2011	4.22% in 2011				
	12.59% in 2012	4.57% in 2012				
<i>Unfunded balance – end of year</i>				\$4,595		\$3,345

2010: Exelon estimates pre-tax 2010 pension expense of \$245 million and 2010 pension contributions of \$765 million.

(1) Pension expenses include settlement charges.

(2) The contributions shown above include estimated pension contributions required under ERISA, as amended, and contributions necessary to avoid benefit restrictions and at-risk status, as defined by the Pension Protection Act of 2006.

(3) The expected return on assets assumption for all scenarios above is 8% for 2011 and 2012.

Note: Slide provided for illustrative purposes and not intended to represent a forecast of future outcomes. Assumes ~25% overall capitalization of pension costs.

Potential Variability in Future OPEB Expense and Contributions



Illustrative Scenario (\$ in millions)	Assumptions		2011		2012	
	Asset Return Experience	Discount Rate	Pre-tax expense	Expected contribution	Pre-tax expense	Expected contribution
Baseline as of September 30, 2010	3.52% in 2010	5.83% in 2010	\$230	\$190	\$240	\$195
	7.37% in 2011	5.01% in 2011				
	7.37% in 2012	5.15% in 2012				
<i>Unfunded balance – end of year</i>				\$2,440		\$2,430
Alternative I	3.52% in 2010	5.83% in 2010	\$210	\$200	\$190	\$205
Mild Stagflation	6.99% in 2011	5.38% in 2011				
	4.80% in 2012	6.40% in 2012				
<i>Unfunded balance – end of year</i>				\$1,910		\$1,755
Alternative II	3.52% in 2010	5.83% in 2010	\$265	\$200	\$260	\$205
V-Shaped Recovery	7.37% in 2011	4.22% in 2011				
	11.58% in 2012	4.57% in 2012				
<i>Unfunded balance – end of year</i>				\$2,730		\$2,820

2010: Exelon estimates pre-tax 2010 OPEB expense of \$190 million and 2010 OPEB contributions of \$190 million.

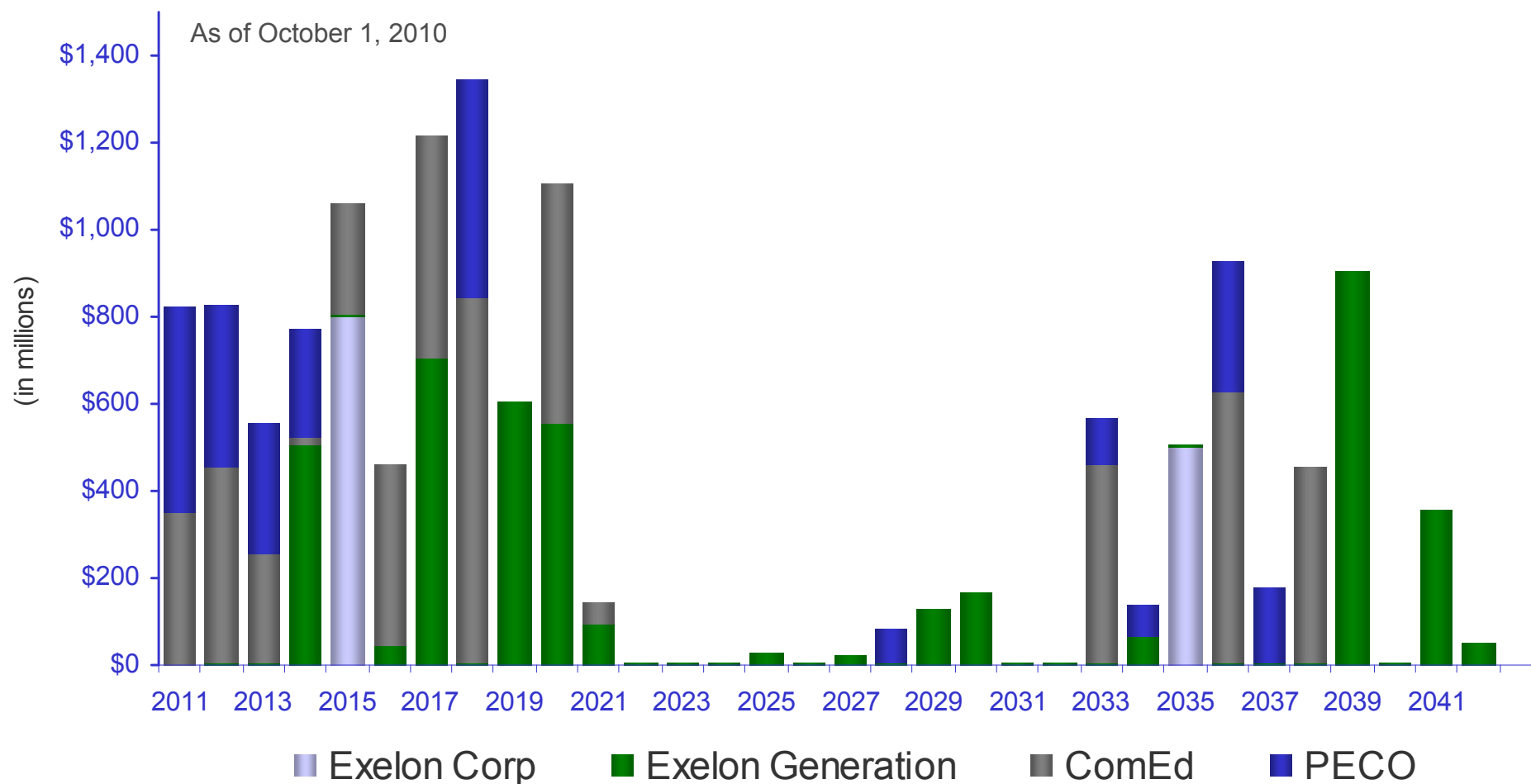
(1) Expense estimates do not include the impact of health care reform legislation (including excise tax).

(2) The contributions shown above are subject to change.

(3) The expected return on assets assumption for all scenarios above is 7.37% for 2011 and 2012.

Note: Slide provided for illustrative purposes and not intended to represent a forecast of future outcomes. Assumes ~25% overall capitalization of OPEB costs.

Debt Maturity Profile



Debt maturities over the next several years are manageable

Note: Balances shown exclude securitized debt and include capital leases.

FFO Calculation and Ratios



FFO Calculation

Net Cash Flows provided by Operating Activities

- +/- Change in Working Capital
- + Other Non-Cash items ⁽¹⁾
- AFUDC/Cap. Interest
- Decommissioning activity
- PECO Transition Bond Principal Paydown

= FFO

FFO Interest Coverage

$$\frac{\text{FFO} + \text{Adjusted Interest}}{\text{Adjusted Interest}}$$

Net Interest Expense

- PECO Transition Bond Interest Expense
- + AFUDC & Capitalized interest
- + Interest on Present Value (PV) of Operating Leases
- + Interest on imputed debt related to PV of Purchased Power Agreements (PPA)

= Adjusted Interest

Debt to Total Cap

$$\frac{\text{Adjusted Book Debt}}{\text{Total Adjusted Capitalization}}$$

Debt:

- + Long-term Debt
- + Short-term Debt
- Transition Bond Principal Balance

= Adjusted Book Debt

$$\frac{\text{Rating Agency Debt}}{\text{Rating Agency Capitalization}}$$

Adjusted Book Debt

- + Off-balance sheet debt equivalents ⁽²⁾

= Rating Agency Debt

Capitalization:

- + Total Shareholders' Equity
- + Preferred Securities of Subsidiaries
- + Adjusted Book Debt

= Total Adjusted Capitalization

Total Adjusted Capitalization

- + Off-balance sheet debt equivalents ⁽²⁾

= Total Rating Agency Capitalization

FFO Debt Coverage

$$\frac{\text{FFO}}{\text{Adjusted Debt}^{(3)}}$$

Debt:

- + Long-term Debt
- + Short-term Debt
- PECO Transition Bond Principal Balance
- + Off-balance sheet debt equivalents ⁽²⁾

= Adjusted Debt

(1) Reflects depreciation adjustment for PPAs and operating leases and pension/OPEB contribution normalization.

(2) Metrics are calculated in presentation unadjusted and adjusted for debt equivalents for PV of Operating Leases, PPAs, unfunded Pension and OPEB obligations (after-tax), Capital Adequacy for Energy Trading, and other minor debt equivalents.

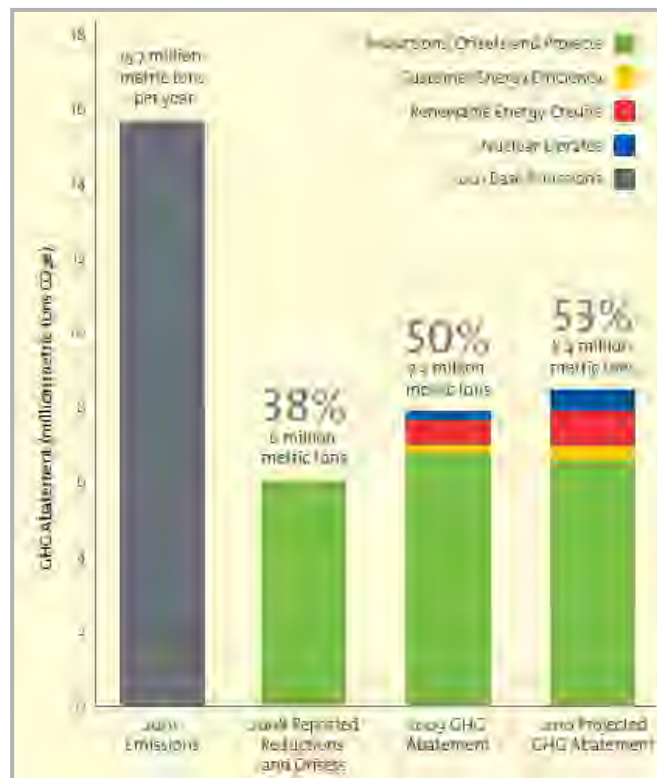
(3) Uses current year-end adjusted debt balance.



Environmental

Recognition for Sustainability and Environmental Leadership

Exelon's 2020 Plan: a low carbon roadmap



CARBON DISCLOSURE PROJECT

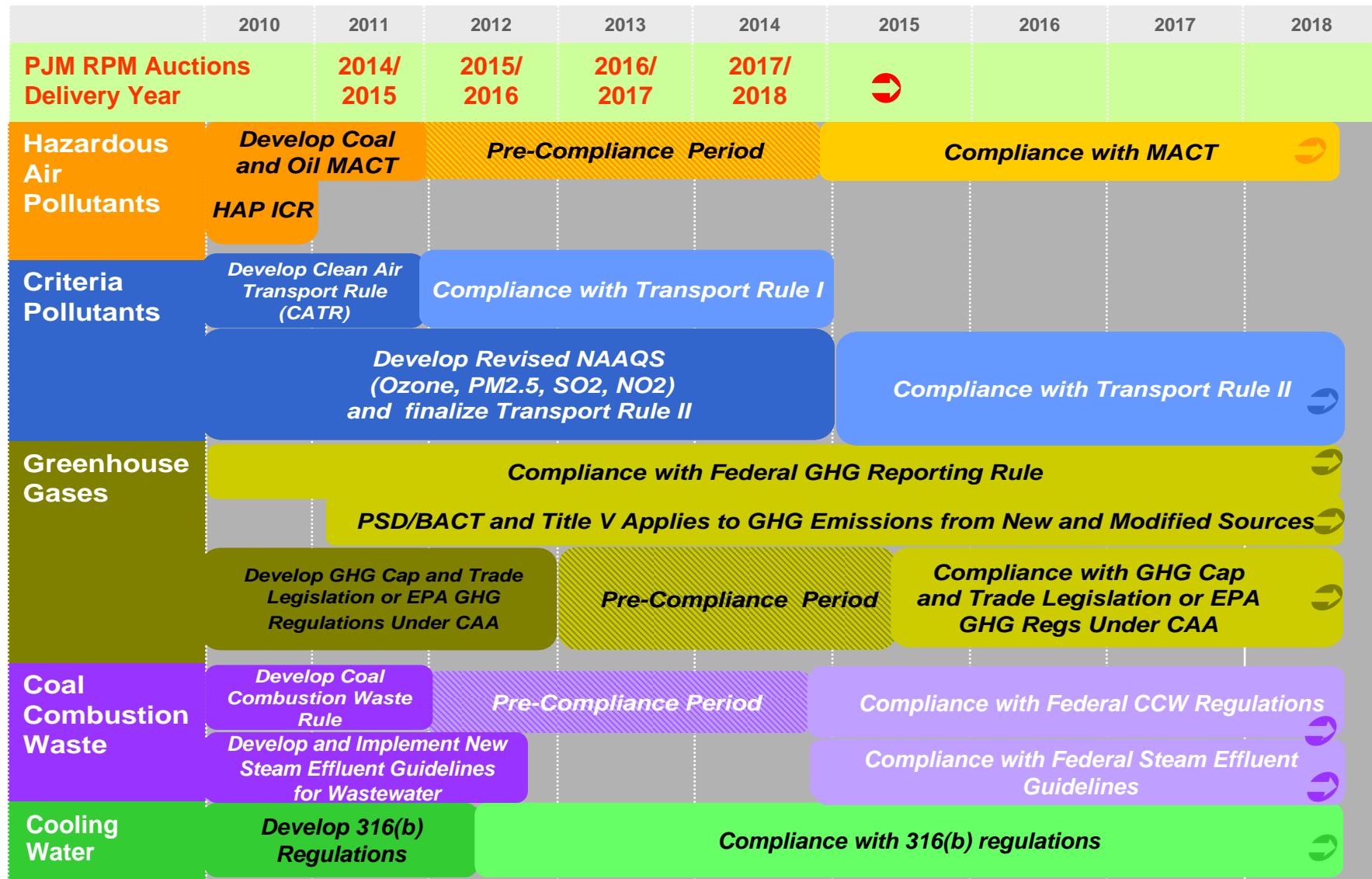
Named to the 2010 Carbon Disclosure Leadership Index



Included in the Dow Jones Sustainability North America Index for the fifth consecutive year

Exelon continues to be recognized for our 2020 plan to reduce, offset, or displace our company's 2001 carbon footprint by the year 2020

EPA Regulations – Market Implications Leading up to 2012 Compliance



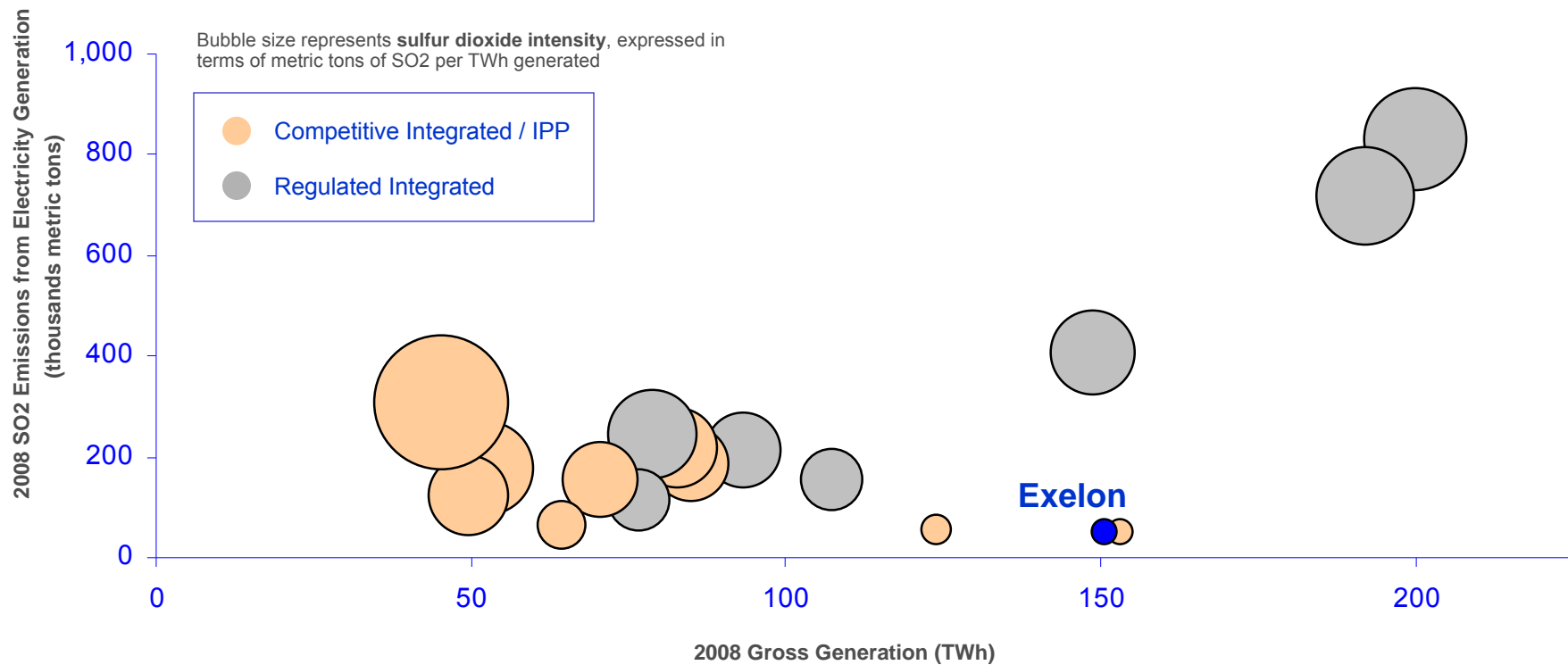
Notes: RPM auctions take place annually in May.

For definition of the EPA regulations referred to on this slide, please see the EPA's Terms of Environment (<http://www.epa.gov/OCEPAterms/>).

Clean, Efficient Fleet Well Positioned for Environmental Regulations



SO₂ Emissions of Largest U.S. Electricity Generators



Using SO₂ emissions as a proxy for hazardous air pollutants, Exelon well positioned for Hazardous Air Pollutant ruling in 2011

Why EPA Regulations Will Not Be Delayed



Opposing Argument	Reality	Supporting Facts
➤ Courts will suspend the rules or the President will intervene	➤ Federal court would have to determine that the rules are inconsistent with applicable law, which is unlikely to occur because the amended rules are aligned with the court's expectations	➤ Up to 1 year extension by EPA only if necessary for installation of controls ➤ President has only used exemption two times in history (only for national security interests)
➤ Costs are prohibitive for industry and consumer	➤ Proven technologies are commercially available and have already been installed demonstrating that the costs can be managed ➤ Total savings to consumer, including healthcare impacts	➤ Well over half of existing units have already installed pollution controls ➤ EPA estimates in 2014 that the proposed Transport Rule will have annual net benefits (in 2006\$) of \$120-290 billion using a 3% discount rate
➤ Timeline is too tight for compliance	➤ Recent industry trends suggest that it is reasonable to install this quantity of scrubbers according to the proposed timeframe.	➤ EPA's modeling indicates that only 14 GW of additional capacity would need to be retrofitted with flue gas desulfurization (FGD) for Phase 2 of the Transport rule (2014) ➤ Industry has already demonstrated ability to schedule and sequence outages to comply
➤ Retirements will cause reliability issues on the grid	➤ Electric system reliability will not be compromised if the industry and its regulators manage the transition	➤ Each NERC region has excess capacity, totaling over 100 GW nationwide ➤ Between 2001-2003, industry built over 160 GW of new generation – four times what is projected will retire over next 5 years

Opposition will have a voice, but the framework and timetable have been set

Providing Relief in Extreme Cases: Statutory and Regulatory Safeguards



Agency	Source of Authority	Supporting Language
EPA	Section 112(i)(3)(B) of the Clean Air Act	The Administrator (or a State with a program approved under subchapter V of this chapter) may issue a permit that grants an extension permitting an existing source up to 1 additional year to comply with standards under subsection (d) of this section if such additional period is necessary for the installation of controls.
U.S. President	Section 112(i)(4) of the Clean Air Act	The President may exempt any stationary source from compliance with any standard or limitation under this section for a period of not more than 2 years if the President determines that the technology to implement such standard is not available and that it is in the national security interests of the United States to do so. An exemption under this paragraph may be extended for 1 or more additional periods, each period not to exceed 2 years. The President shall report to Congress with respect to each exemption (or extension thereof) made under this paragraph.
U.S. Department of Energy	Section 202(c) of the Federal Power Act	Override CAA-derived control requirements in limited emergency circumstances.

Extensions for plants to comply will be on a plant-by-plant basis, for a limited time period, and only if specific “tests” are met

EPA Clean Air Standards Will Not Threaten Electric System Reliability



- M.J. Bradley and Analysis Group report ⁽¹⁾ in August 2010 concluded industry is well-positioned to respond to proposed standards
 - System has >100 GW of excess capacity
 - Regulators have tools to address localized reliability concerns, including appropriate price signals from capacity markets
 - Industry has proven track record of adding generation capacity and transmission solutions
- New clean air standards will help modernize US power generation infrastructure
 - Proven technologies for controls are commercially available: >50% of coal units have installed controls demonstrating that compliance costs can be managed
 - Pollution-intensive plant retirements will create room for cleaner, more efficient generation

Proactive steps by EPA, the industry and other agencies will allow orderly plant retirements without impacting system reliability

(1) M.J. Bradley & Associates, LLC and Analysis Group. 2010. *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability*. Full study available at www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf.

Retiring Cromby Station and Eddystone Units 1&2



- Agreed to delay deactivation of two units to maintain reliability ⁽¹⁾, provided receipt of required environmental permits and adequate cost-based compensation
 - Maintained scheduled retirement date of 5/31/11 for Cromby 1 and Eddystone 1
 - Revised retirement dates for Cromby 2 to 12/31/11 and Eddystone 2 to 6/01/12
- RMR filed with FERC in 2Q10
 - Establishes terms and conditions under which Cromby 2 and Eddystone 2 will operate during RMR period
 - Allows Exelon to recover costs of operating and maintaining units under Cost of Service Recovery Rate
 - Estimated at \$2.6 million per RMR-month for Cromby Unit 2 and \$8.8 million per RMR-month for Eddystone Unit 2, plus recovery of project investment
 - In September 2010, FERC issued order accepting RMR filing, but set matter for hearing to review additional information to justify Cost of Service mentioned above
 - Currently in settlement discussions with interveners; targeting final approval by 4Q10
- RMR Unit Operating Limitations
 - Dispatched and operated solely for reliability purposes
 - Unable to bid into PJM RPM capacity auctions

Exelon's experience with Cromby Station & Eddystone units 1 and 2 is an example of how to work with stakeholders to reliably retire uneconomic coal

(1) See PJM's website (<http://www.pjm.com/planning/generation-retirements/gr-study-results.aspx>) for additional details regarding PJM's Deactivation Study and Exelon's response.
Note: RMR = reliability must-run agreement

Exelon's Exposure to EPA Regulations



EPA Regulation	Units Affected	Exelon Investment Needed ⁽¹⁾	Industry Impact ⁽²⁾
Hazardous Air Pollutants	Keystone & Conemaugh ⁽³⁾ Oil-Fired Units >25 MW: ~935 MW	Included in CATR costs Impact to be determined	Significant, primarily fossil fuel-fired generation
Criteria Pollutants / CATR	Keystone & Conemaugh ⁽³⁾ Fossil-fuel fired units >25 MW: ~4,000 MW ⁽⁴⁾	~\$100 million None anticipated	Compliance costs of up to \$2.8 billion / year
GHG Tailoring Rule	None ⁽⁵⁾	None	Significant, primarily fossil fuel-fired generation
Coal combustion waste	Keystone & Conemaugh ⁽³⁾	Subtitle C: < \$100 million ⁽⁶⁾ Subtitle D: no impact	Compliance costs up to \$20 billion
316(b) or Cooling Water	Facilities without closed-cycle recirculating systems (e.g. cooling towers) <u>POWER</u> : Schuylkill, Eddystone 3 & 4, Fairless Hills, Mountain Creek, Handley <u>NUCLEAR</u> : Clinton, Dresden, Quad Cities, Oyster Creek, Peach Bottom, Salem	Impact to be determined once rule is promulgated; Cost to retrofit Oyster Creek and Salem estimated at \$700-800 million and \$500 million, respectively ⁽³⁾	Significant, impacts all fuel types including large base load and intermediate units

(1) These rules are in the proposed or pre-proposed stage and estimates are based on published cost studies used as inputs to IPM modeling.

(2) EPA's estimated costs, where applicable.

(3) Investment needed shown is Exelon's share of the cost. Exelon owns 21% share in Keystone and Conemaugh and 42.59% share in Salem. Keystone & Conemaugh units all have scrubbers and Keystone units have SCRs. Oyster Creek and Salem investment estimates based on 2006 studies.

(4) Exelon's existing coal-fired units will be retired before this rule will take effect.

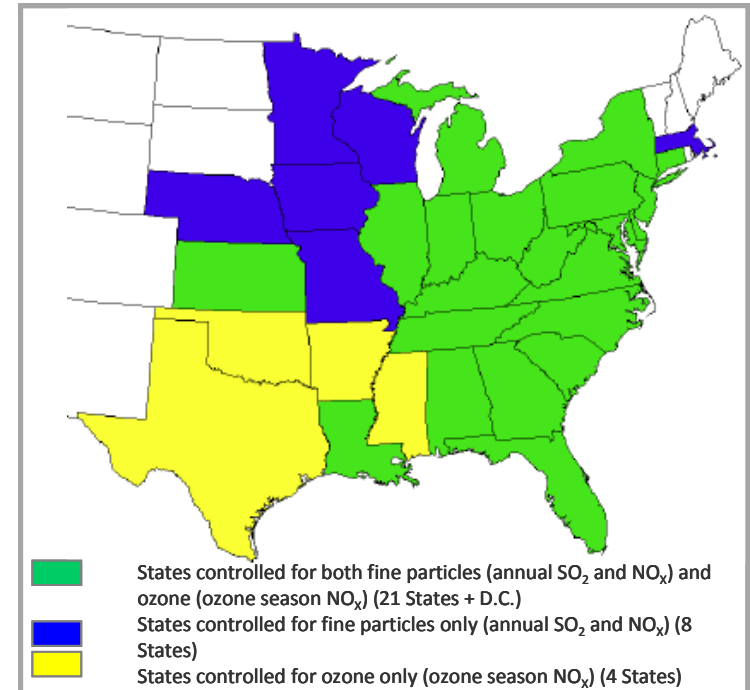
(5) This rule applies only to new sources or major modifications of existing sources.

(6) Excludes Eddystone 1 and 2 and Cromby, which are scheduled to retire in 2011 and 2012.

Clean Air Transport Rule



- EPA proposed the Transport Rule on July 6, 2010 to replace CAIR (Clean Air Interstate Rule)
 - Exelon filed comments in support of Transport Rule on October 1
 - Final rule expected from EPA by June 2011
- Would require 31 states and the District of Columbia to significantly improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other states
 - Requires significant reductions in sulfur dioxide (SO₂) and nitrogen oxide (NO_x)
- EPA estimates annual compliance cost at \$2.8 billion, but would yield healthcare savings of \$120 - \$290 billion in 2014
- EPA has proposed three implementation alternatives for public comment, but its preference is the "State Budgets/Limited Trading" option that establishes state-specific emission budgets and allows for intrastate and limited interstate trading



Source: EPA

Compliance set to begin on January 1, 2012

Exelon's View on FERC NOPR

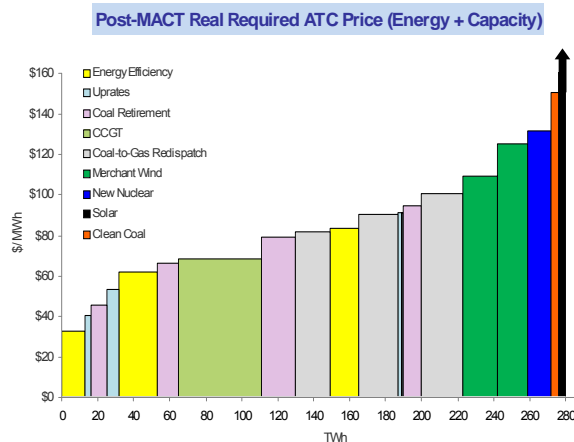


- **On June 17, 2010, FERC issued a Notice of Proposed Rulemaking (NOPR) on Transmission Planning and Cost Allocation. NOPR proposals include:**
 - Modify planning processes for public policy mandates, such as renewable energy standards (RES)
 - Increase intra- and inter-regional planning coordination
 - Eliminate existing preferences in FERC tariffs for incumbent transmission facility developers to build needed transmission
 - Embrace broad application of “beneficiary pays” standard for cost allocation

- **Exelon generally supports the NOPR and proposes the following:**
 - Mandate stronger inter-regional planning requirements, such as PJM coordination with MISO to accommodate new transmission
 - Maintain the right of first refusal by incumbent transmission owners for local reliability projects
 - Require planning for enforceable state public policy mandates, as well as EPA rules that affect capacity requirements
 - Allocate costs to loads that benefit

Exelon continues to advocate for fair and appropriate planning rules for new transmission to address state and federal policy

Exelon 2020 Supply Curve – Supporting Details



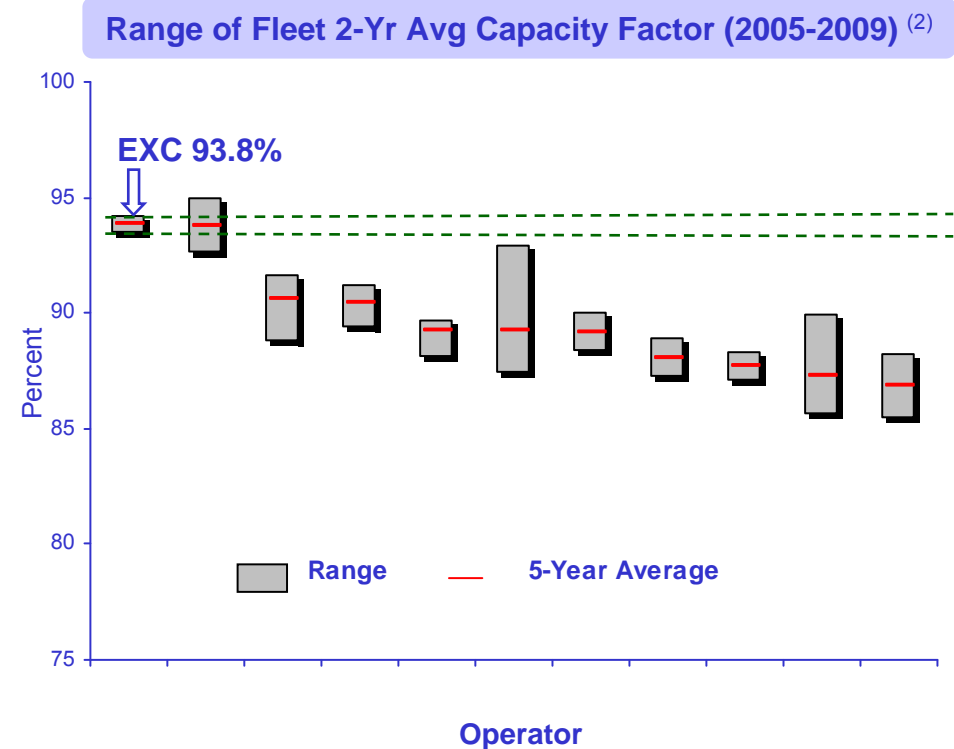
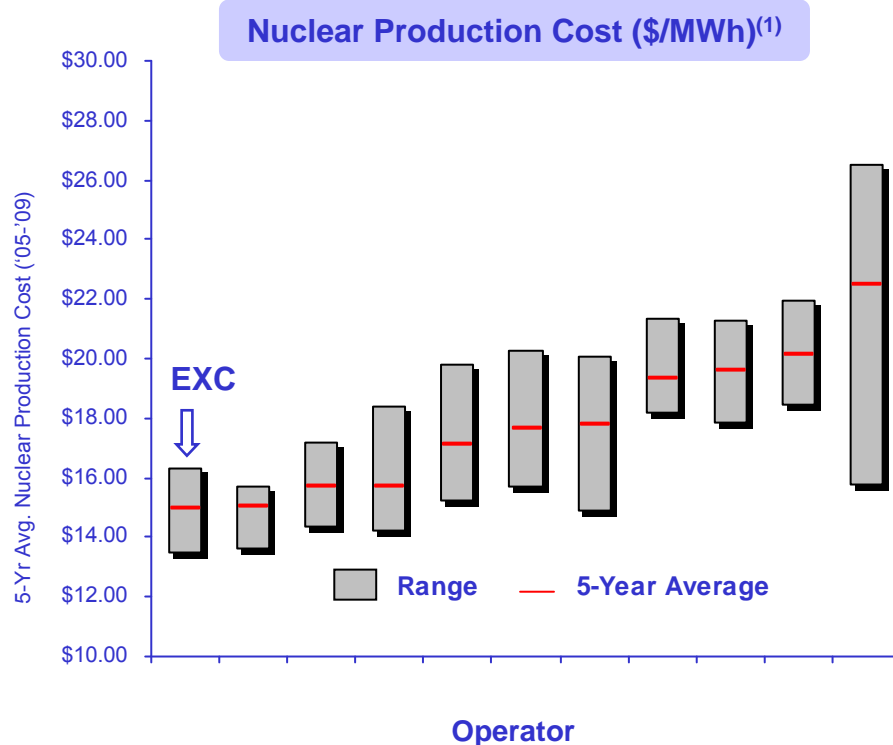
Category	Explanation
Energy Efficiency (EE)	The first 1% of a 4.25% total EE target, which would be in line with a 17% RPS target that allows up to a quarter of the target to be met with EE.
Upgrades	Exelon's MURs and LP Turbines.
Coal Retirement	Capacity expected to retire due to power prices (based on low gas) and CATR. Eddy and Cromby are representative of this bucket.
Upgrades	Exelon's EPU's
EE	The next 2% of a 4.25% total EE target.
Coal Retirement	Additional capacity that retires as a result of HAPs MACT regulation. Total of 11 GW of coal expected to retire between this bar and the first coal retirement bar.
CCGT	New CCGTs that get built in PJM by 2020 due to expected impact from MACT and nominal demand growth.
Coal Retirement	Incremental retirements that would result from CATR + a carbon price (no MACT assumed).
Coal-to-Gas Redispatch	Incremental gas-fired generation -- displacing generation that would otherwise come from coal (not coal retirements)
EE	The last 1.25% of a 4.25% total EE target
Coal-to-Gas Redispatch	Incremental gas-fired generation resulting from a higher carbon price.
Upgrades	Upgrades at nuclear plants that are not currently planned. Assumed to be subsidized cost of a new nuclear plant.
Coal Retirement	Incremental retirements that would result from CATR + MACT + carbon price.
Coal-to-Gas Redispatch	Incremental gas-fired generation resulting from a higher carbon price.
Wind	Western PJM half of total new wind build of 13 GW resulting from 17% RPS target (wind is assumed to meet this target, less the 25% contribution from EE).
Wind	Eastern PJM half of total new wind build of 13 GW resulting from 17% RPS target (wind is assumed to meet this target, less the 25% contribution from EE).
New Nuclear	Estimate of constructing new nuclear unit
Clean Coal	Estimate of constructing a clean coal plant
Solar	Solar installation in the Pennsylvania market.

Note: Represents a single economic and power market outlook, which is indicative of a range of scenarios.



Generation

World-Class Nuclear Operator



Among major nuclear plant fleet operators, Exelon is consistently one of the lowest-cost producers of electricity in the nation

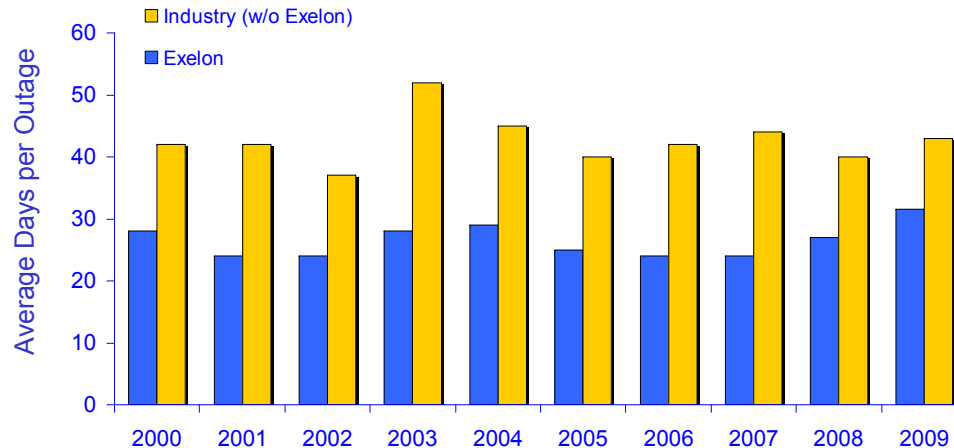
(1) Source: 2009 Electric Utility Cost Group (EUCG) survey. Includes Fuel Cost plus Direct O&M divided by net generation.

(2) Source: Platts Nuclear News, Nuclear Energy Institute and Energy Information Administration (Department of Energy).

Impact of Refueling Outages



Refueling Outage Duration



Note: Exelon data includes Salem. 2009 average includes 23 days of TMI outage that extended into 2010 reflecting steam generator replacement.

Nuclear Refueling Cycle

- All Exelon owned units on a 24 month cycle except for Braidwood U1/U2, Byron U1/U2 and Salem U1/U2, which are on 18 month cycles
- Average Outage Duration (2008-9): ~29 days⁽¹⁾

2010 Refueling Outage Impact

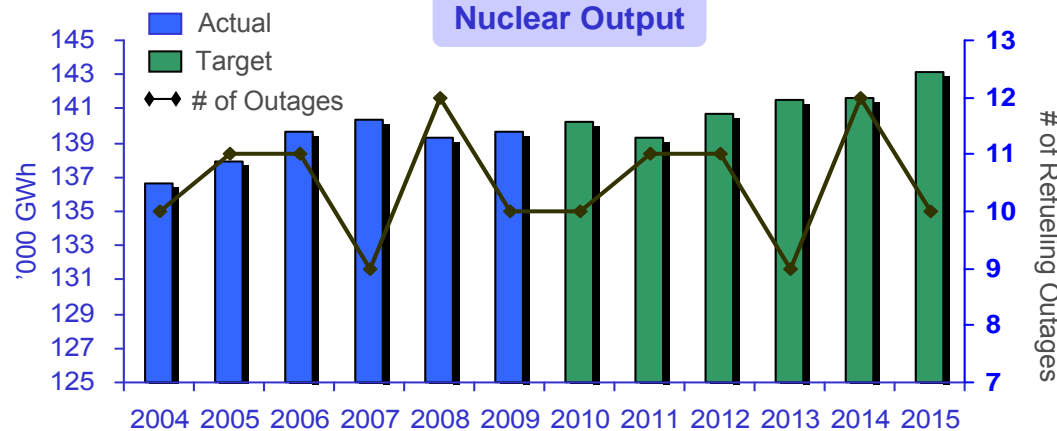
- 10 planned refueling outages, including 1 at Salem
- Completed 6 refueling outages in the Spring with an average duration of 25 days
- 4 planned Fall refueling outages (Peach Bottom 2, Oyster Creek, Braidwood 1 and Dresden 3)

2011 Refueling Outage Impact

- 11 planned refueling outages, including 2 at Salem
- 6 refueling outages planned for the Spring and 5 refueling outages planned for the Fall

(1) Includes Salem and 23 days of TMI 2009 outage that extended into 2010 reflecting steam generator replacement.

Nuclear Output

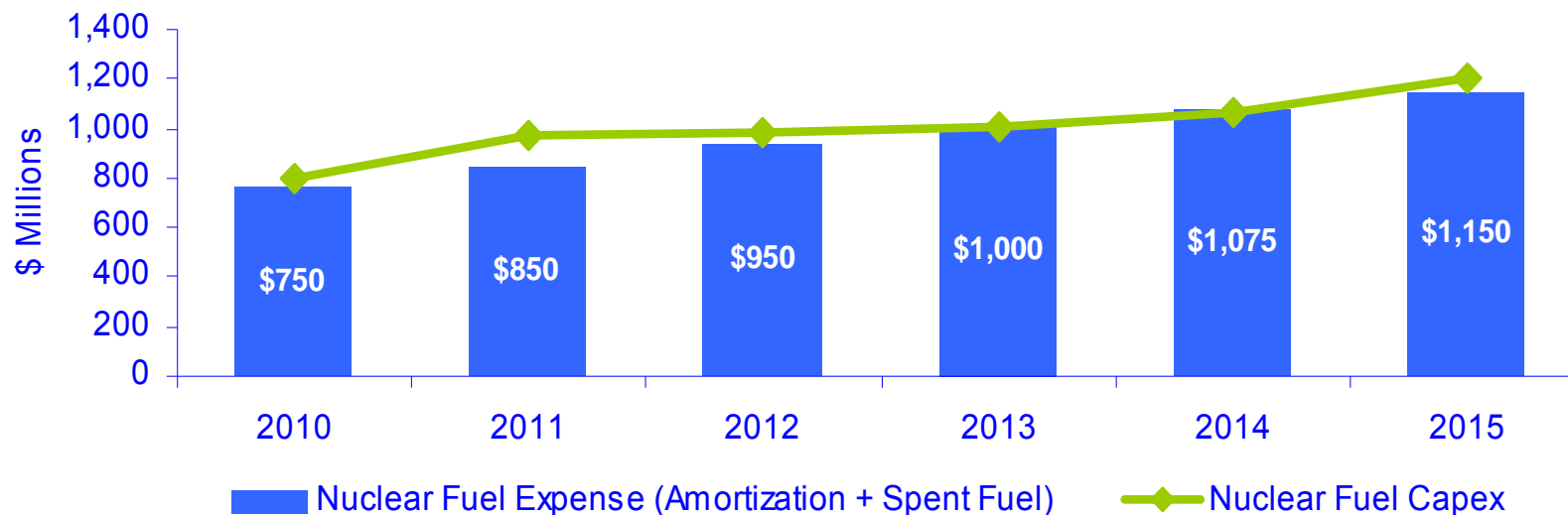


Note: Data includes Salem. Net nuclear generation data based on ownership interest.

Projected Total Nuclear Fuel Spend



- Nuclear fuel expense is amortized over three refueling outage cycles
- Nuclear fuel capital expenditures are recognized in the period of investment

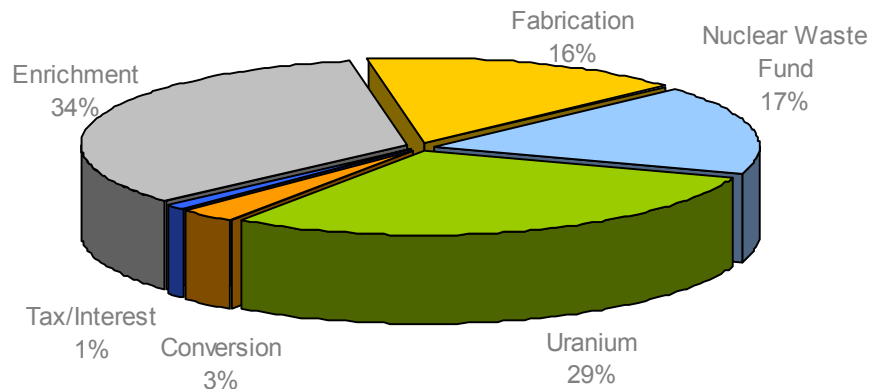


Exelon Generation is the largest uranium user in the U.S. and uses diverse sources and contract terms to manage supply



Effectively Managing Nuclear Fuel Costs

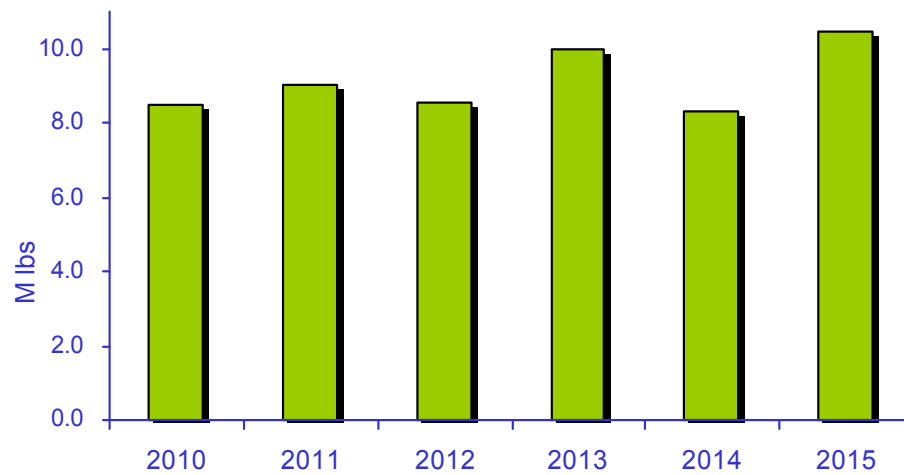
Components of Fuel Expense in 2010



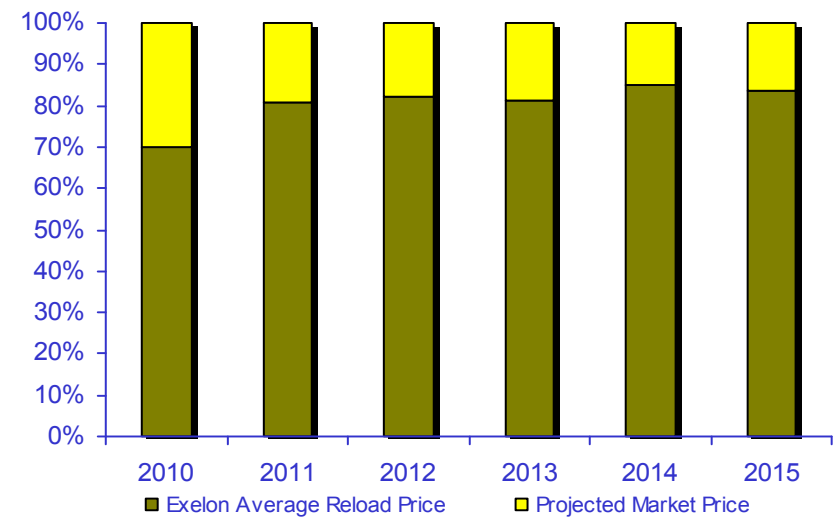
- Exelon Nuclear's uranium demand is 100% physically hedged for 2010-2015
- Contracted prices continue to be below market prices
- Uranium prices were volatile over last 5 years, but have stabilized in the \$40-\$60/lb range

Projected Exelon Uranium Demand

2010 – 2015: 100% hedged in volume



Projected Exelon Average Uranium Cost vs. Market





Nuclear Upgrades Offer Sustainable Value

Strategic Value

- Key component of Exelon 2020 low carbon roadmap
- Creates additional low-carbon generation capacity
- Upgrades equivalent in size to a new nuclear plant but significantly lower cost, shorter timeline, and more predictable expenditures

Regulatory Feasibility

- Straightforward regulatory and environmental licenses, permits and approvals
- Potential for upgrades to meet state alternative energy standards

Execution Feasibility

- No ongoing incremental O&M expense
- Capitalizes on Exelon's proven track record of upgrade execution
- Dedicated project management team
- Proven technology design
- Allows us to adjust timing to respond to market conditions

Upgrade projects enable cost-effective growth and leverage Exelon's operation excellence

Three Major Categories of Exelon Upgrades



Upgrades	Overnight Cost ⁽¹⁾		Project Duration	Estimated Internal Rate of Return
Megawatt Recovery and Component Upgrades				
239–260 MW	\$790M	<ul style="list-style-type: none"> Replacement of major components in the plant occur in the normal life cycle process – with newer technology, replacements result in increased efficiency Equipment includes generators, turbines, motors and transformers Megawatt Recovery and Component Upgrades must conform to NRC standards, but do not require additional NRC approval 	3-4 years	12-14%
MUR (Measurement Uncertainty Recapture)				
190–233 MW	\$310M	<ul style="list-style-type: none"> Through the use of advanced techniques and more precise instrumentation, reactor power can be more accurately calculated Can achieve up to 1.7% additional output Requires NRC approval 	2 years	14-16%
EPU (Extended Power Upgrade) ⁽²⁾				
899–1,015 MW	\$2,550M	<ul style="list-style-type: none"> Through a combination of more sophisticated analysis and upgrades to plant equipment, upgrades can increase output by as much as 20% of original licensed power level Requires NRC approval 	3 - 6 years	11-14%
~1,300–1,500 MW	\$3,650M			

Refined scenario analysis highlights that upgrades continue to be economic, although TMI and Clinton are under review

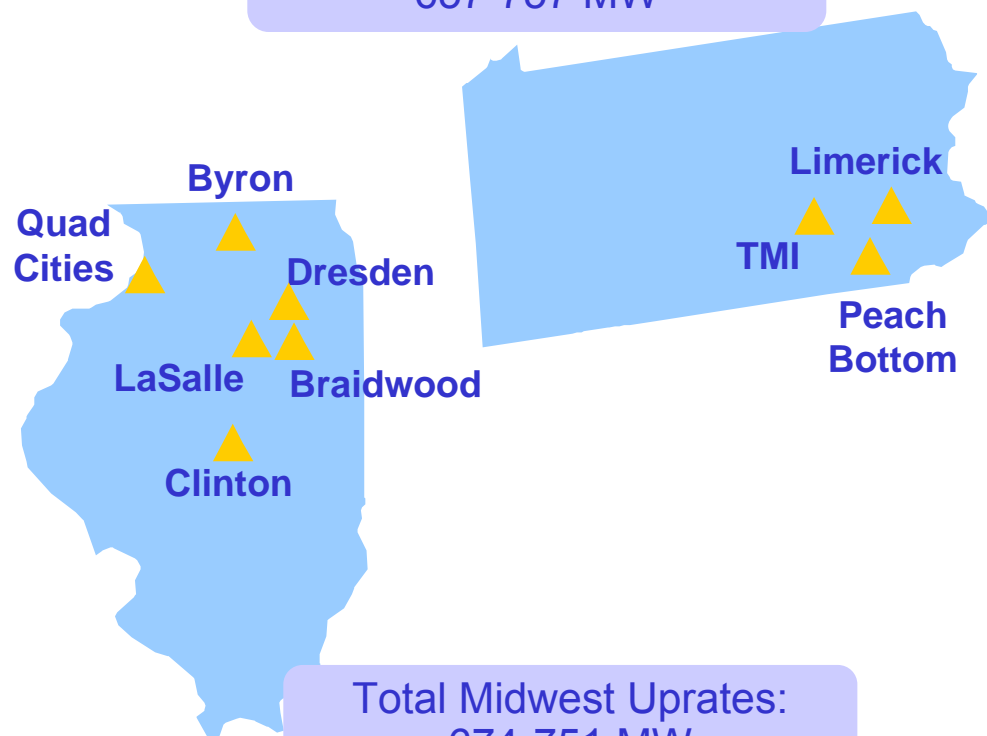
(1) In 2010 dollars. Overnight costs do not include financing costs or cost escalation.

(2) Includes TMI and Clinton EPUs; which are currently under review.

Multi-Regional Nuclear Uprate Program



Total Mid-Atlantic Uprates:
657-757 MW



Total Midwest Uprates:
674-751 MW

Under review

Executing uprate projects across our geographically diverse nuclear fleet

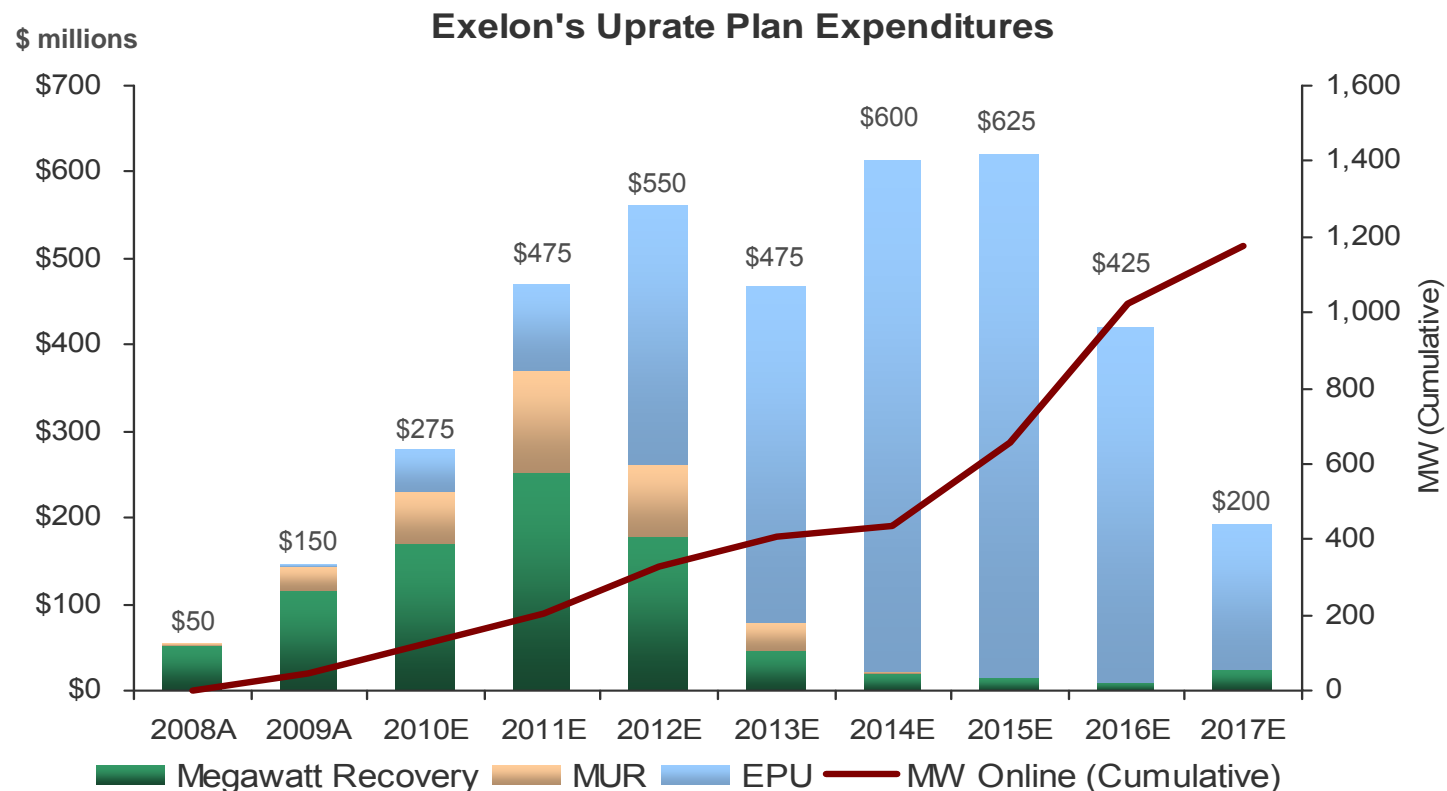
Notes: MW shown at ownership. An additional 23 MW expected to come online by end of 2010 at Limerick 1 and Dresden 3.

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	61	2011 / 2010
Dresden	5	5		2011 / 2012
Peach Bottom	25	32		2011 / 2012
Dresden	103	110	12	2012 / 2013
Limerick	6	6		2012 / 2013
Peach Bottom	3	3		2014 / 2015
MUR:				
LaSalle	35	39	19	2011 / 2011
Limerick	33	41		2011 / 2011
Braidwood	34	42		2012 / 2012
Byron	34	42		2012 / 2012
Quad Cities	19	23		2013 / 2013
Dresden	25	31		2014 / 2013
TMI	12	15		2014
EPU:				
Clinton	2	2	2	2010
Peach Bottom	134	148		2015 / 2016
Clinton	17	17		2016
LaSalle	303	336		2016 / 2015
TMI	138	172		2016
Limerick	306	340		2016 / 2017
Total	1,331	1,508	94	



Phased Execution Lowers Risk

- Highest return projects are being completed in the early years
- Leverages Exelon's substantial experience managing successful uprate projects – 1,100 MW completed between 1999 - 2008



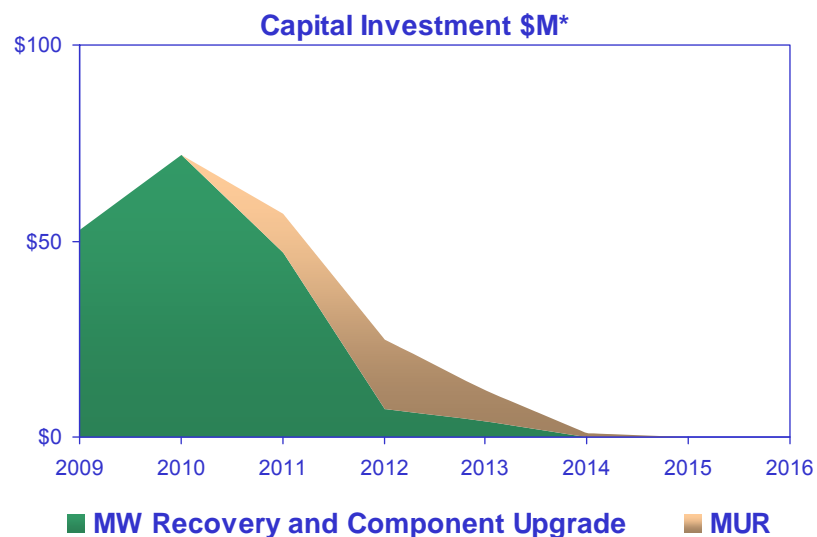
Approximately 117 MW scheduled to be completed in 2009 and 2010; total expenditures expected to be \$3,825 million from 2008 – 2017 ⁽¹⁾⁽²⁾

(1) Dollars shown are nominal, reflecting 6% escalation, in millions.
 (2) Excludes TMI and Clinton EPU's, which are currently under review.

Note: MW shown at ownership. Data contained in this slide is rounded.



Quad Cities Uprate Program



➤ MW Recovery

- Unit 2 Low Pressure Turbine Retrofit completed April 2010, increase of 50 MW achieved
- Unit 1 Low Pressure Retrofit planned for Spring 2011
- Partial completion of Unit 1 work has resulted in an increase of 11 MW

➤ MUR

- Planned start date of project will be in 2011
- Timing of uprate will be dependent on NRC approval of license amendment

➤ EPU

- Completed in 2002

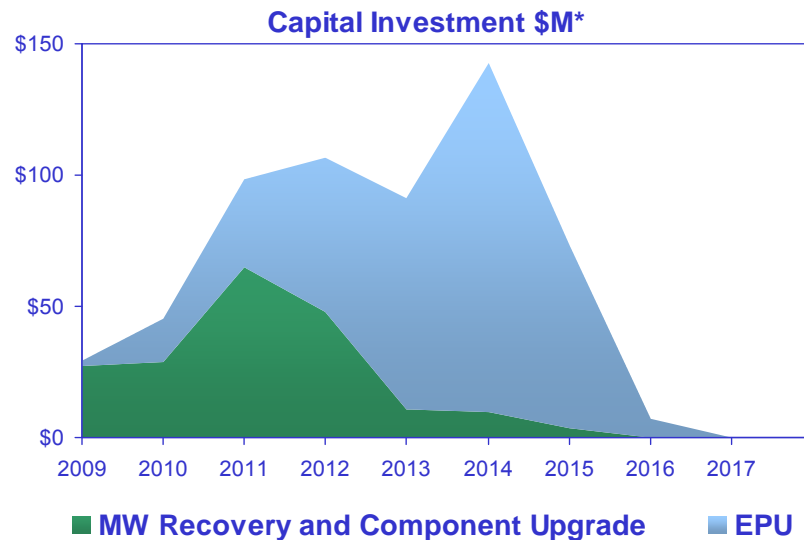
Uprate Project	Unit 1		Unit 2		Status
	MW Increase*	Online Date	MW Increase*	Online Date	
MW Recovery (Low Pressure Turbine Retrofit)	47	3Q2011	50	2Q2010	In progress
MUR	9	2Q2013	9	1Q2013	Scheduled start in 2011

* Capital investment and MW uprate numbers represent Exelon's 75% ownership stake in Quad Cities Station.

Quad Cities Uprate Projects are underway – additional MWs will come on line between 2010 and 2013



Peach Bottom Uprate Program



➤ MW Recovery

- Project in progress with Low Pressure Turbine Retrofit installations expected in 2011 and 2012
- Replace Reactor Recirculation Pump Motor Generator sets with energy efficient Adjustable Speed Drives in 2014 and 2015

➤ MUR

- Completed in 2003

➤ EPU

- Funding approved for design work
- Will review in 2011 before authorizing installation funding for physical plant modifications and purchase of materials

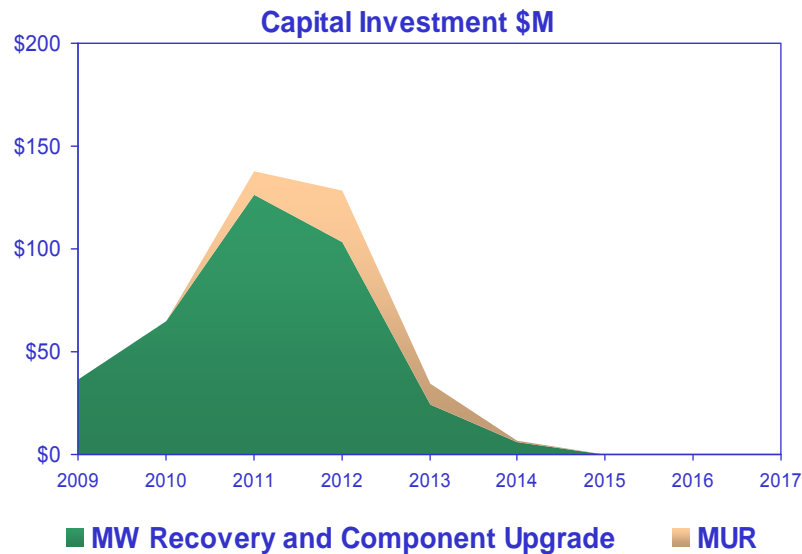
	Unit 2		Unit 3		
Uprate Project	MW Increase*	Online Date	MW Increase*	Online Date	Status
MW Recovery (Low Pressure Turbine Retrofit)	14	4Q2012	11	4Q2011	In progress
MW Recovery (Adjustable Speed Drives)	2	4Q2014	2	4Q2015	Scheduled to start in 2012
EPU	67	1Q2015	67	1Q2016	Design phase in progress

* Capital investment and MW uprate numbers represent Exelon's 50% ownership stake in Peach Bottom Station.

Peach Bottom Uprate Projects are underway – additional MWs will come online between 2011 and 2016



Dresden Uprate Program



➤ MW Recovery

- Project in progress with Low Pressure Turbine Retrofit installations expected in 2011 and 2012
- Partial completion of Unit 2 work has resulted in an increase of 12 MW
- Replace Reactor Recirculation Pump Motor Generator sets with energy efficient Adjustable Speed Drives in 2011 and 2012

➤ MUR

- Planned start date of project will be in 2011
- Timing of uprate will be dependent on NRC approval of license amendment

➤ EPU

- Completed in 2002

	Unit 2		Unit 3		
Uprate Project	MW Increase	Online Date	MW Increase	Online Date	Status
MW Recovery (Adjustable Speed Drives)	3	4Q2011	3	4Q2012	In progress
MW Recovery (Low Pressure Turbine Retrofit)	52	1Q2012	51	1Q2013	In progress
MUR	12	1Q2014	12	1Q2013	Scheduled start in 2011

Dresden Uprate Projects are underway – additional MWs will come online between 2011 and 2014



Zion Station Decommissioning

- On September 1, 2010, Exelon transferred license to EnergySolutions, which will dismantle the Zion Nuclear Generating Station
 - Located in Northeast Illinois, Zion ceased operations in 1998
 - Commercial operations began in 1973 for Unit 1 and 1974 for Unit 2
- \$1 billion, 10-year project will be the largest nuclear dismantling ever undertaken in the U.S.
 - Entire cost of decommissioning will be funded through the station's decommissioning trust fund
 - No operating income statement impact for Exelon
- Exelon will retain ownership of the plant's spent nuclear fuel, which must remain on the property in a secure facility
- Once decommissioning is completed, responsibility for the site will be transferred back to Exelon



Approval received from Nuclear Regulatory Commission in first-of-its kind agreement



Exelon Nuclear Fleet Overview

Plant, Location	Units	Type	Vendor	Net Annual Mean Rating MW 2009	License Status / Expiration ⁽¹⁾	Ownership	Spent Fuel Storage/ Date to lose full core discharge capacity ⁽³⁾
Braidwood, IL	2	PWR	W	1194, 1166	2026, 2027	100%	2013
Byron, IL	2	PWR	W	1183, 1153	2024, 2026	100%	2011
Clinton, IL	1	BWR	GE	1065	2026	100%	2018
Dresden, IL	2	BWR	GE	869, 871	Renewed: 2029, 2031	100%	Dry cask
LaSalle, IL	2	BWR	GE	1138, 1150	2022, 2023	100%	2010
Limerick, PA	2	BWR	GE	1148, 1145	2024, 2029	100%	Dry cask
Oyster Creek, NJ	1	BWR	GE	625	Renewed: 2029	100%	Dry cask
Peach Bottom, PA	2	BWR	GE	574, 571 ⁽²⁾	Renewed: 2033, 2034	50% Exelon, 50% PSEG	Dry cask
Quad Cities, IL	2	BWR	GE	655, 662 ⁽²⁾	Renewed: 2032	75% Exelon, 25% Mid-American Holdings	Dry cask
TMI-1, PA	1	PWR	B&W	837	Renewed: 2034	100%	2025
Salem, NJ	2	PWR	W	503, 500 ⁽²⁾	In process (decision in 2011-2012): 2016, 2020	42.6% Exelon, 57.4% PSEG	2011

Average in-service time = 29 years

License extensions will be pursued for all units not already renewed

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

(2) Capacity based on ownership interest.

(3) 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 the closing of their on-site storage pools.

Note: Fleet also includes 4 shutdown units: Peach Bottom 1, Dresden 1, Zion 1 & 2.

John Deere Renewables Acquisition – Transaction Summary



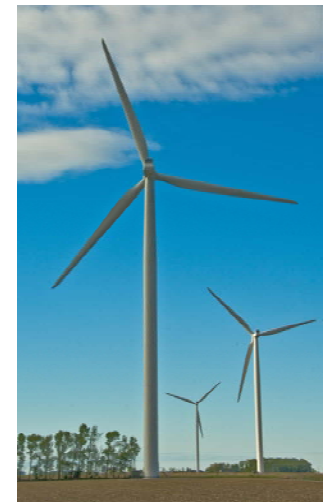
Deal Structure

- 735 MW operating portfolio spread across 36 projects located in eight states with 230 MW in Michigan in late stage development
- \$860M purchase price plus up to \$40M for Michigan development projects, funded by \$900 million debt issuance at Exelon Generation
- 75% of the operating portfolio is sold under long-term power purchase arrangements; 86% of contracted portfolio has PPAs through 2026 or beyond
- Additional 1,238 MW in development pipeline
- EBITDA run-rate of ~\$150M/year including Production Tax Credits (and including Michigan development projects)

Strategic Rationale

- Diversify with clean generation – unique entry point into wind generation
- Contracted portfolio with option for future growth
- Attractive economics and good fit

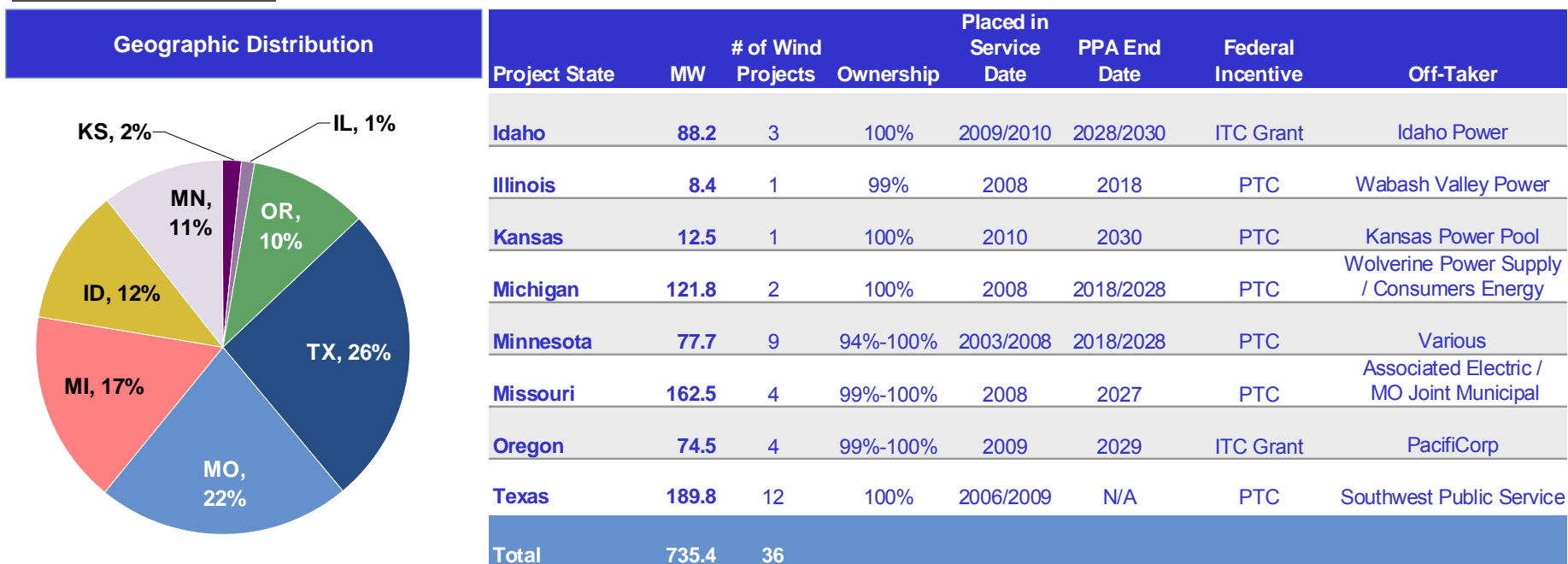
Expect to close transaction in 4Q 2010



John Deere Renewables Acquisition Asset Profile



Operating Assets



Projects to be Developed by Exelon

State	Project Name	MW
MI	Michigan Wind II	90
MI	Harvest II	59
MI	Blissfield (MW IV)	81
Total		230

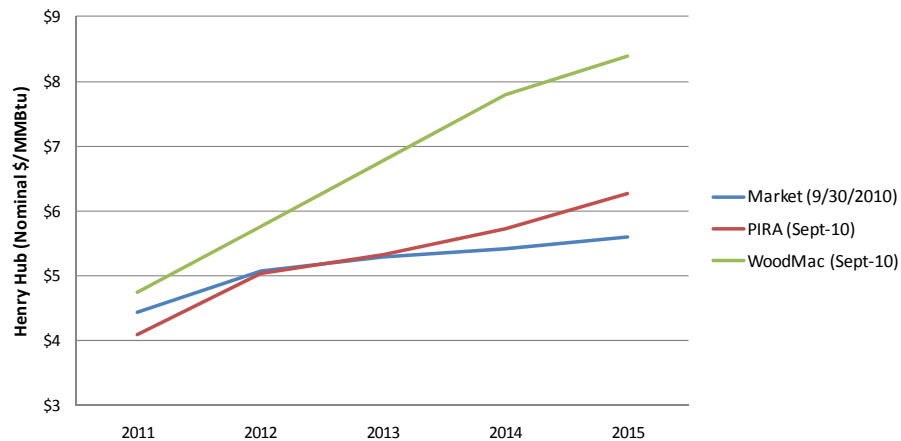
- Additional 1,238 MW development pipeline includes wind projects ranging from 20 MW to 300 MW
- Development of projects to be considered on a case-by-case basis

Note: There is ongoing litigation with Southwest Public Service related to PURPA contracts which could affect the price at which the generation from these units is sold. Cracking issues experienced by Deere on certain Suzlon turbine blades have been addressed to our satisfaction. We have factored both items into our valuation.

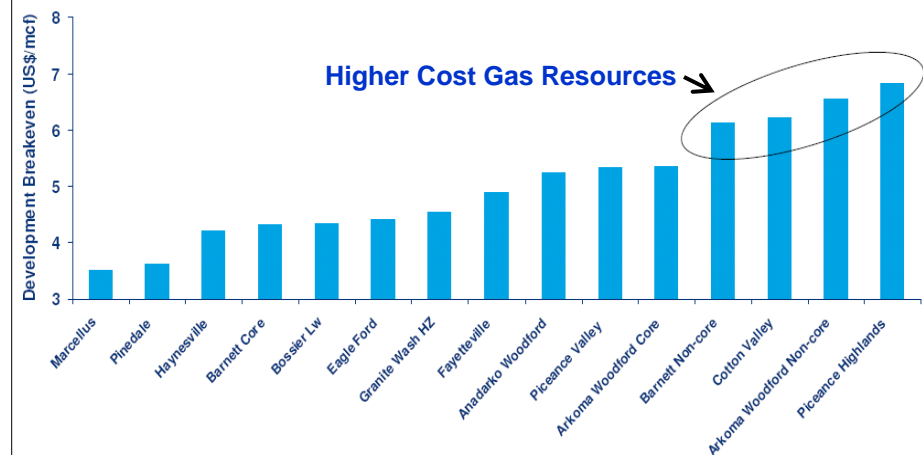
Natural Gas Outlook



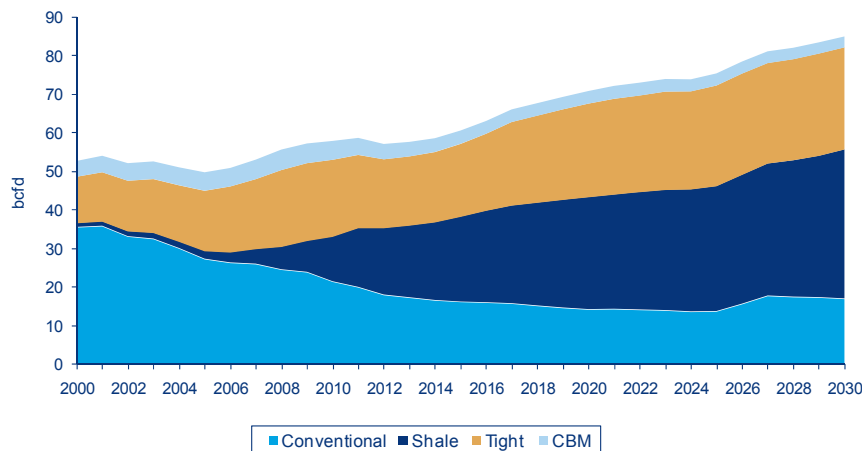
Natural Gas Price Forecasts



Key North American Supply Sources (2015)



U.S. Production by Type



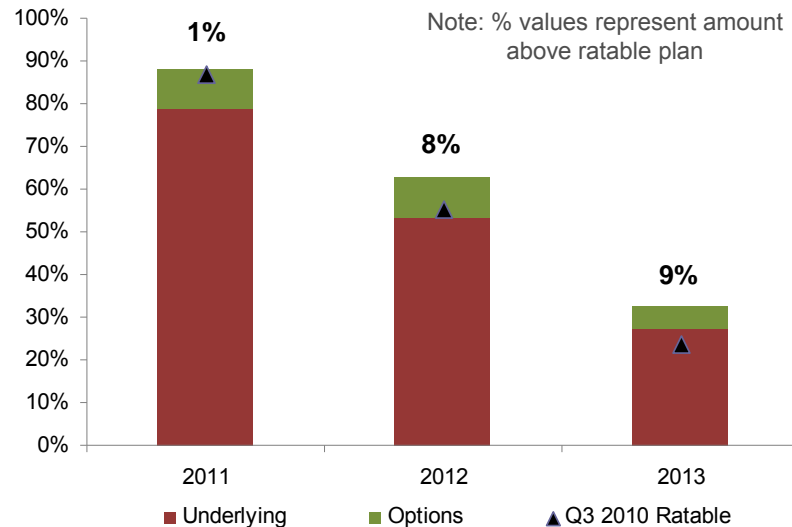
- The economic recovery has increased natural gas demand, but this has been met by sufficient supply
- Shale gas has proven itself to be a low cost and abundant resource, but not the only resource
 - Most production growth is expected to come from shale resulting in a flatter gas supply curve
 - Non-core shale, tight sands and coal bed methane resources are higher cost and will remain part of the total supply mix
- A flatter supply curve provides market stability, but increased drilling costs, environmental concerns and uncertainty regarding shale decline rates could put upward pressure on the marginal cost of gas and therefore prices

Current fundamentals support a forward natural gas price in the \$5-\$6.50/MMBtu range

Exelon Generation Hedging Program

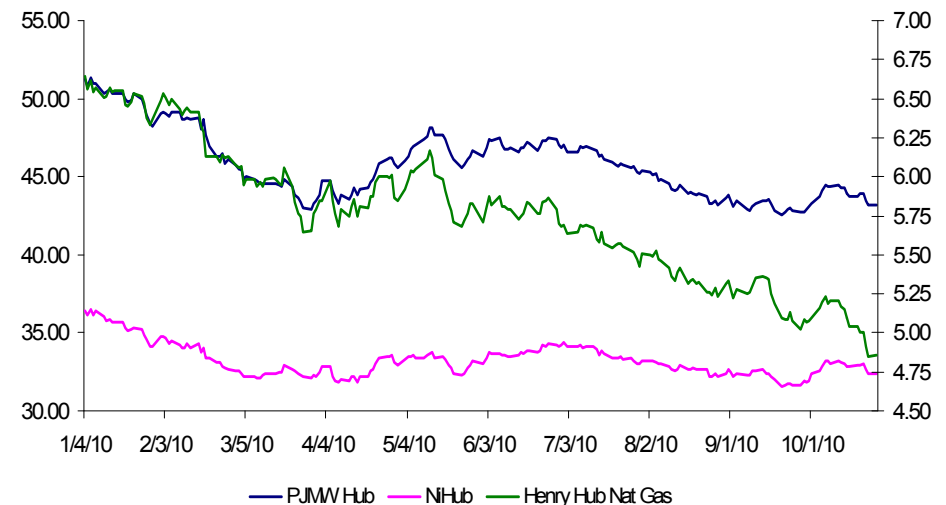


Current Hedge Level vs. Ratable Plan (1)



(1) Data as of end of 3Q 2010.

2012 Historical Power & Gas Prices



➤ **Normal practice is to hedge commodity risk on a ratable basis over three years**

- Maintain flexibility from quarter to quarter
- Use of gas and power options to capture potential upside while providing downside price protection

➤ **2012 hedging levels currently above ratable**

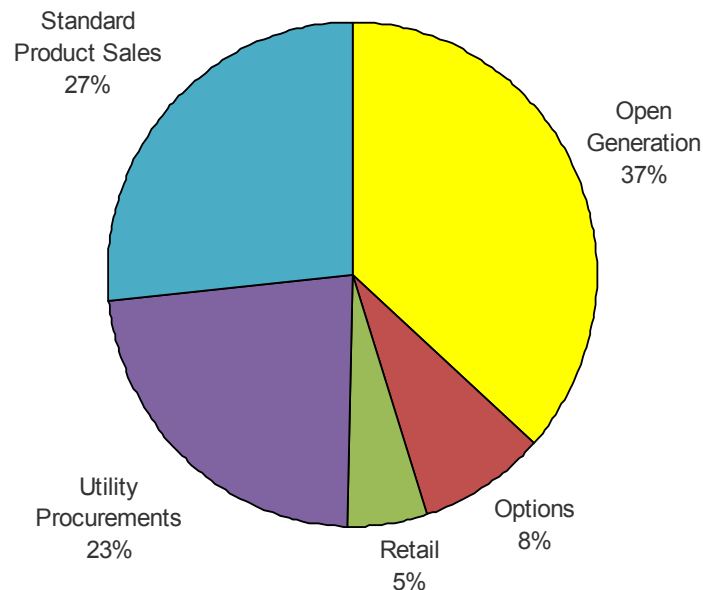
- Increased rate of 2012 sales in 2nd Quarter of 2010 to capture higher prices in Mid-Atlantic, and slowed down in Q3 as prices fell
- Participation in long-term procurements

Exelon's ratable hedging program provides flexibility to time sales based on fundamental view of the market

Multiple Channels To Market



2011 - 2013 Sales as a Percentage of Expected Generation ⁽¹⁾



➤ A diverse set of customers and products is important for Exelon Generation's hedging program

- Reduces and diversifies our collateral exposure
- Improves portfolio product fit (load following) and sales closer to assets
- Increases opportunities for margin via retail, utility solicitations and mid-marketing channels
- Long term transactions provide extended price certainty and monetize environmental upside
- Use of alternate channels and locations help minimize liquidity constraints

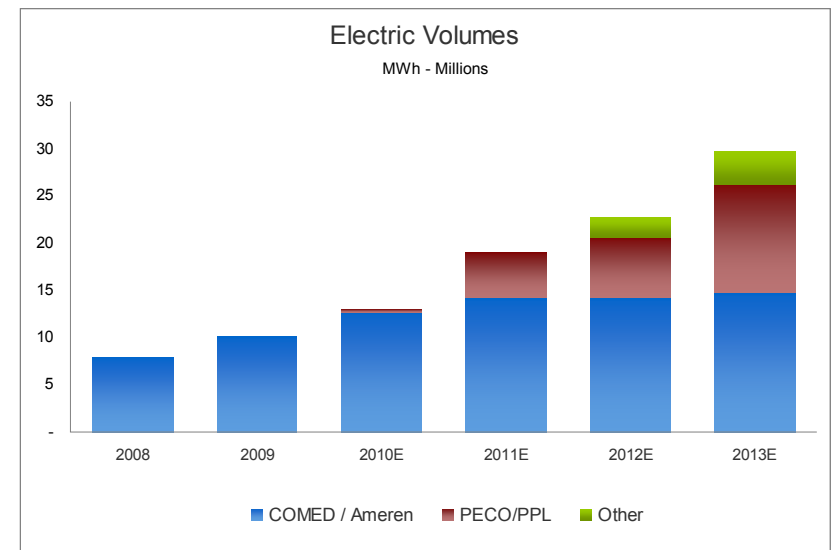
Multiple sales channels to market enhances value and maximizes liquidity and credit diversity

(1) Represents values as of September 30, 2010.

Exelon Energy – Competitive Retail



- **Supplies a wide range of energy and natural gas products directly to commercial and industrial customers in Illinois, Pennsylvania, Michigan and Ohio**
- **Managed as a part of the overall Exelon Generation hedging strategy**
 - Retail load profile complements generation portfolio
 - Long term sales agreements with creditworthy customers reduces portfolio price and earnings risk
 - Projected sales growing from ~10% to 20% of expected generation over the next 3 years
- **Channel to build relationship with end-use customers**
 - Partner with customers to meet their energy supply needs
 - Products support Exelon 2020 and provide access to Exelon Generation's low-emission generation fleet
 - Renewable Energy Credits (RECs), including John Deere wind resources
 - Low Carbon Energy Certificates (EDECs)
 - Nuclear energy attributes transferred through PJM Generation Attribute Tracking System



Exelon Energy complements Exelon Generation footprint by leveraging broad experience in wholesale markets and asset management

Reliability Pricing Model (RPM) Auction



Exelon Generation Eligible Capacity within PJM Reliability Pricing Model ⁽¹⁾

<i>in MW</i>	2010/2011		2011/2012	2012/2013	2013/2014
	<u>Capacity ⁽²⁾</u>	<u>Obligation</u>	<u>Capacity ⁽²⁾</u>	<u>Capacity ⁽²⁾</u>	<u>Capacity ⁽²⁾</u>
RTO	23,900	9,300 - 9,400 ⁽³⁾	22,300	11,600	10,300
	\$174.29		\$110.00	\$16.46	\$27.73
EMAAC				8,700 ⁽⁴⁾	8,700 ⁽⁴⁾
	\$174.29		\$110.00	\$139.73	\$245.00
MAAC				1,500	1,500
	\$174.29		\$110.00	\$133.37	\$226.15
Avg (\$/MW-Day) ⁽⁵⁾	\$174.29		\$110.00	\$74.00	\$134.00

(1) All generation values are approximate and not inclusive of wholesale transactions.

(2) All capacity values are in installed capacity terms (summer ratings) located in the areas and capacity values have been adjusted for mid year PPA roll offs. JDR assets are not included in the capacity position.

(3) Obligation consists of load obligations from PECO. PECO PPA expires December 2010.

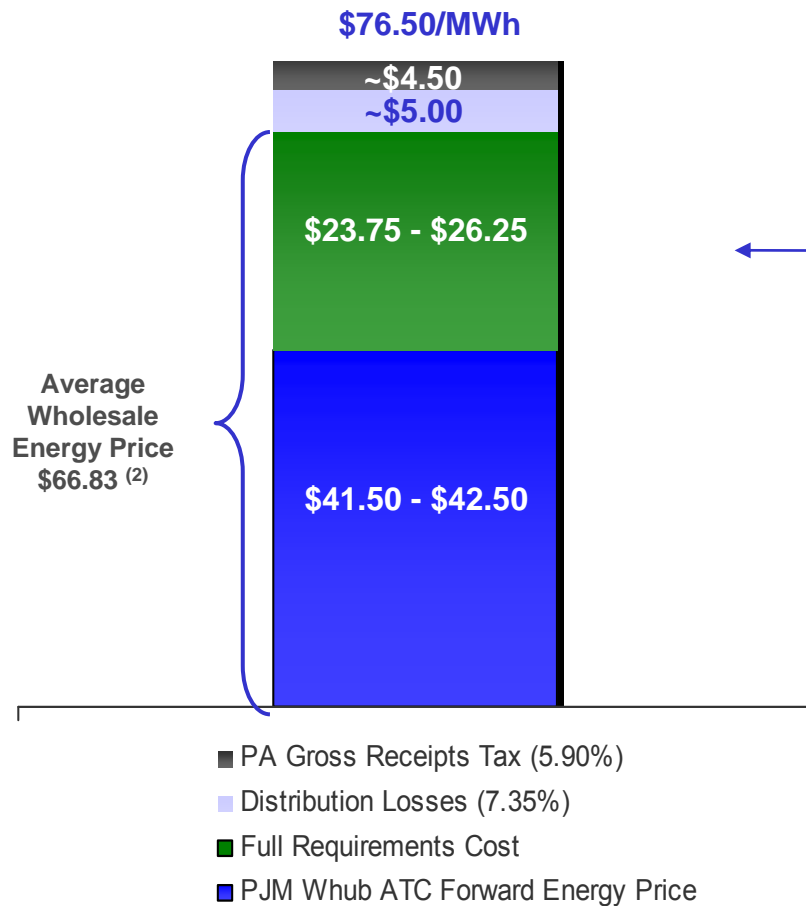
(4) Reflects decision in December 2009 to permanently retire Cromby Station and Eddystone Units 1&2 as of 5/31/11. None of these 933 MW cleared in the 2011/2012 or 2012/2013 auctions.

(5) Weighted average \$/MW-Day would apply if all generation cleared in the highlighted zones.

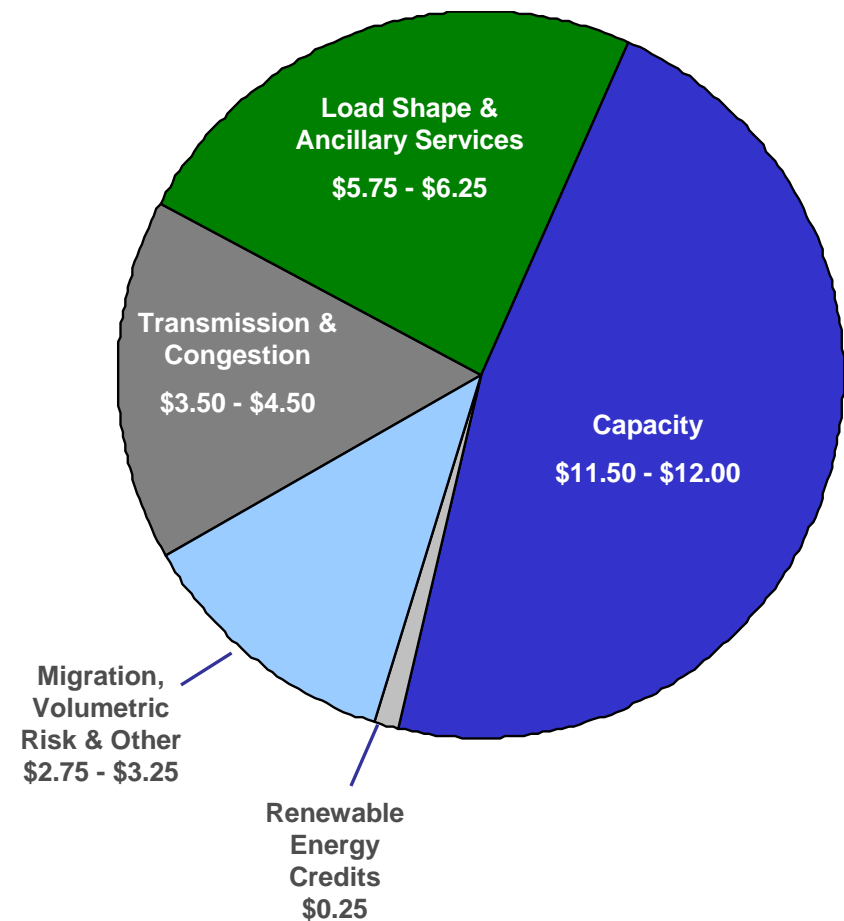
Estimated Build-Up of PECO Average Residential Full Requirements Price – Fall 2010



Average Full Requirements Retail Sales Price ⁽¹⁾



Full Requirements Costs (\$/MWh)



(1) As provided by Exelon Generation.

(2) On October 14, 2010 the Independent Evaluator (NERA) announced a wholesale winning bid of \$66.83/MWh for PECO's Fall 2010 RFP Residential Price.



Exelon Generation Hedging Disclosures

(as of September 30, 2010)

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, 2010. 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.

Portfolio Management Objective

Align Hedging Activities with Financial Commitments



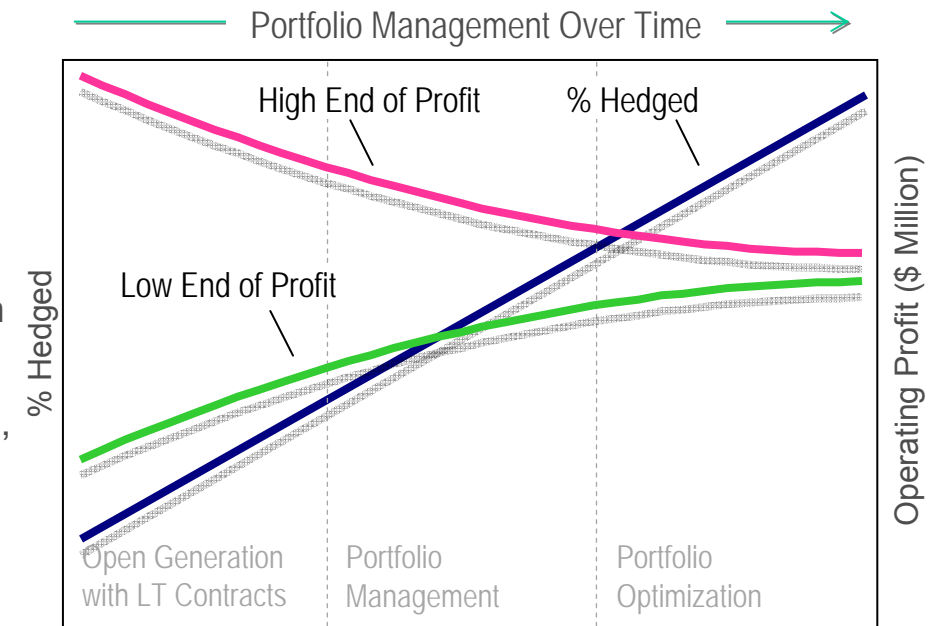
➤ **Exelon's hedging program is designed to protect the long-term value of our generating fleet and maintain an investment-grade balance sheet**

- 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
- Block products
- Load-following products and load auctions
- Put/call options
- Heat rate options
- Fuel products
- Capacity
- 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



	2011	2012	2013
Estimated Open Gross Margin (\$ millions) ⁽¹⁾⁽²⁾	\$4,800	\$4,700	\$5,300

Open gross margin assumes all expected generation is sold at the Reference Prices listed below

Reference Prices ⁽¹⁾

Henry Hub Natural Gas (\$/MMBtu)	\$4.44	\$5.07	\$5.29
NI-Hub ATC Energy Price (\$/MWh)	\$29.92	\$31.89	\$34.04
PJM-W ATC Energy Price (\$/MWh)	\$41.07	\$43.10	\$45.02
ERCOT North ATC Spark Spread (\$/MWh) ⁽³⁾	\$(0.37)	\$0.31	\$1.52

(1) Based on September 30, 2010 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



	2011	2012	2013
Expected Generation (GWh) ⁽¹⁾	163,400	162,700	161,100
Midwest	99,100	96,900	95,300
Mid-Atlantic	56,500	57,100	56,400
South	7,800	8,700	9,400
Percentage of Expected Generation Hedged ⁽²⁾	87-90%	62-65%	31-34%
Midwest	86-89	61-64	28-31
Mid-Atlantic	93-96	66-69	36-39
South	62-65	49-52	35-38
Effective Realized Energy Price (\$/MWh) ⁽³⁾			
Midwest	\$44.00	\$43.50	\$43.00
Mid-Atlantic	\$57.50	\$50.50	\$52.00
ERCOT North ATC Spark Spread	\$(1.00)	\$(4.50)	\$(7.50)

(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 11 refueling outages in 2011 and 2012 and 9 refueling outages in 2013 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 93.3%, 93.1% and 93.3% in 2011, 2012 and 2013 at Exelon-operated nuclear plants. These estimates of expected generation in 2011, 2012 and 2013 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. Current RMR discussions do not impact metrics presented in the hedging disclosure.

(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.

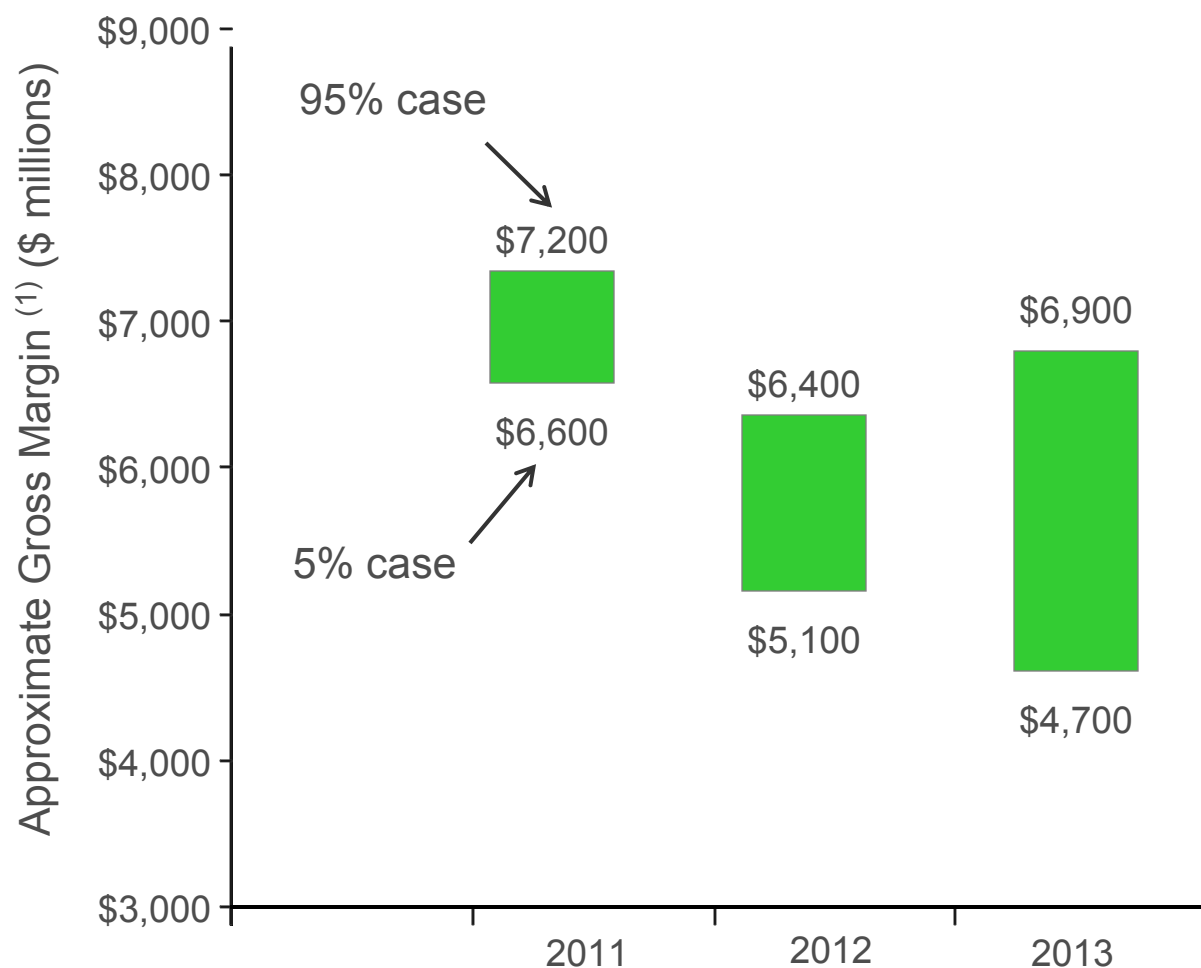
Exelon Generation Gross Margin Sensitivities (with Existing Hedges)



	2011	2012	2013
Gross Margin Sensitivities with Existing Hedges (\$ millions)⁽¹⁾			
Henry Hub Natural Gas			
+ \$1/MMBtu	\$30	\$225	\$455
- \$1/MMBtu	\$(15)	\$(175)	\$(420)
<hr/>			
NI-Hub ATC Energy Price			
+\$5/MWH	\$60	\$205	\$345
-\$5/MWH	\$(50)	\$(195)	\$(340)
<hr/>			
PJM-W ATC Energy Price			
+\$5/MWH	\$20	\$120	\$200
-\$5/MWH	\$(15)	\$(115)	\$(195)
<hr/>			
Nuclear Capacity Factor			
+1% / -1%	+/- \$40	+/- \$40	+/- \$45

(1) Based on September 30, 2010 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 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, 2010.

Illustrative Example

of Modeling Exelon Generation 2011 Gross Margin
(with Existing Hedges)



	Midwest	Mid-Atlantic	ERCOT
Step 1 Start with fleetwide open gross margin	<div> <div></div> <div>\$4.80 billion</div> <div></div> </div>		
Step 2 Determine the mark-to-market value of energy hedges	99,100GWh * 87% * (\$44.00/MWh-\$29.92/MWh) = \$1.21 billion	56,500GWh * 94% * (\$57.50/MWh-\$41.07/MWh) = \$0.87 billion	7,800GWh * 63% * (\$1.00/MWh-\$0.37/MWh) = \$(0.00) 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:	\$4.80 billion <u>\$1.21billion + \$0.87billion + \$(0.00) billion</u> \$6.88 billion	

Current Market Prices



	Units	2008 ⁽¹⁾	2009 ⁽¹⁾	2010 ⁽⁵⁾	2011 ⁽⁶⁾	2012 ⁽⁶⁾	2013 ⁽⁶⁾
<u>PRICES (as of September 30, 2010)</u>							
PJM West Hub ATC	(\$/MWh)	68.52 ⁽²⁾	38.30 ⁽²⁾	44.38	41.06	43.09	45.01
PJM NiHub ATC	(\$/MWh)	49.00 ⁽²⁾	28.86 ⁽²⁾	32.82	29.91	31.88	34.05
NEPOOL MASS Hub ATC	(\$/MWh)	80.56 ⁽²⁾	42.02 ⁽²⁾	48.33	44.73	47.99	50.43
ERCOT North On-Peak	(\$/MWh)	73.36 ⁽³⁾	33.50 ⁽³⁾	40.13	39.21	45.23	48.19
Henry Hub Natural Gas	(\$/MMBTU)	8.85 ⁽⁴⁾	3.94 ⁽⁴⁾	4.42	4.44	5.07	5.29
WTI Crude Oil	(\$/bbl)	104.49 ⁽⁴⁾	61.56 ⁽⁴⁾	77.28	84.35	87.12	88.22
PRB 8800	(\$/Ton)	12.17	9.20	12.62	14.93	15.56	16
NAPP 3.0	(\$/Ton)	105.36	50.98	65.37	70	72	70
<u>ATC HEAT RATES (as of September 30, 2010)</u>							
PJM West Hub / Tetco M3	(MMBTU/MWh)	6.97	8.26	10.15	8.33	7.83	7.92
PJM NiHub / Chicago City Gate	(MMBTU/MWh)	5.57	7.36	7.31	6.70	6.31	6.47
ERCOT North / Houston Ship Channel	(MMBTU/MWh)	7.42	7.95	7.23	7.69	7.77	7.98

(1) 2008 and 2009 are actual settled prices.

(2) Real Time LMP (Locational Marginal Price).

(3) Next day over-the-counter market.

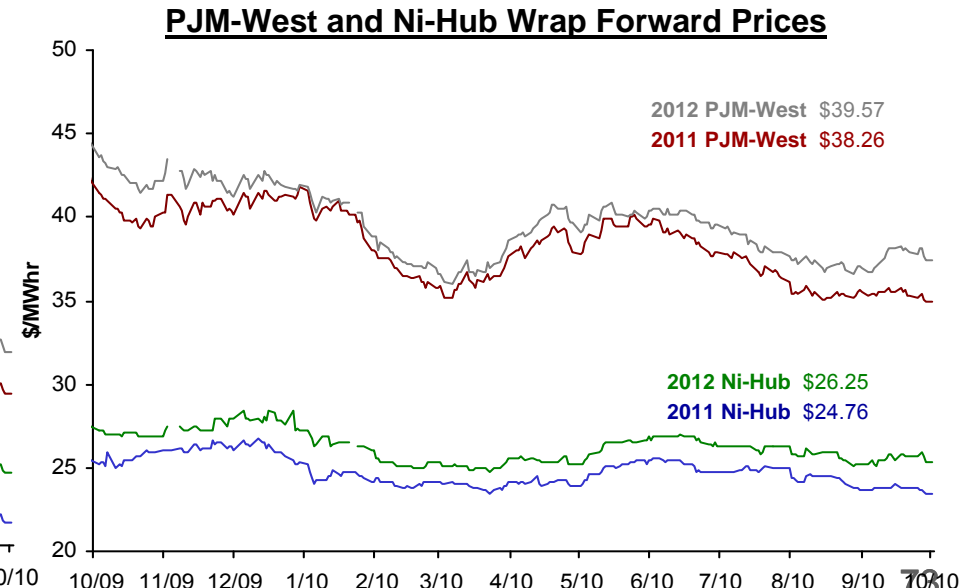
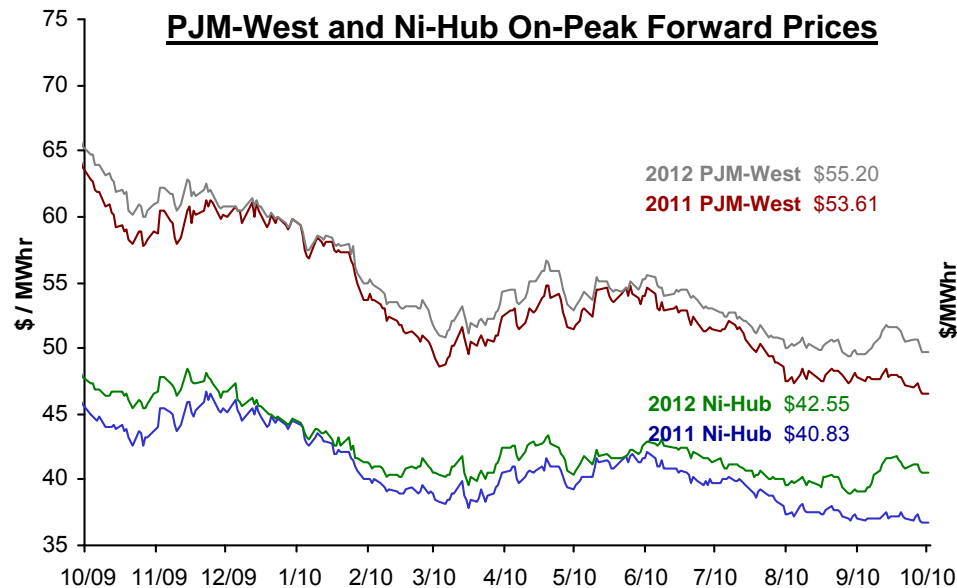
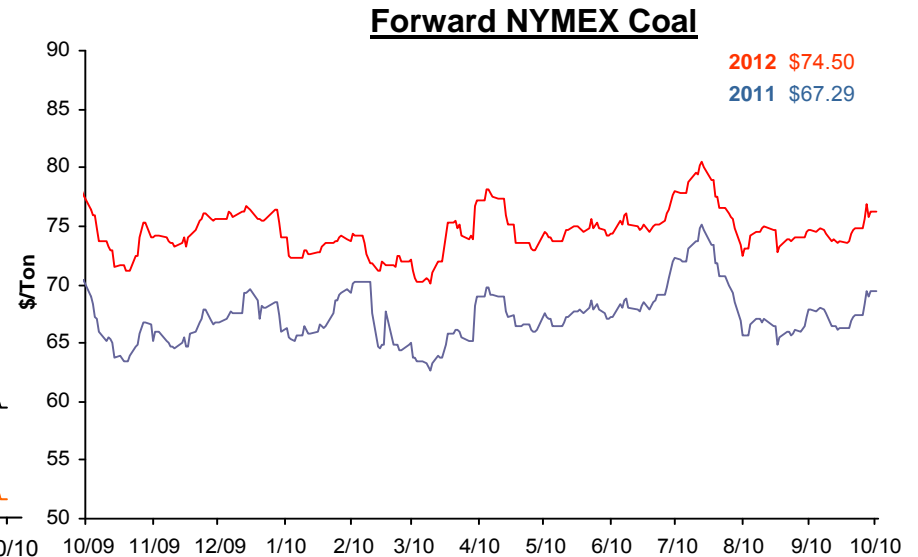
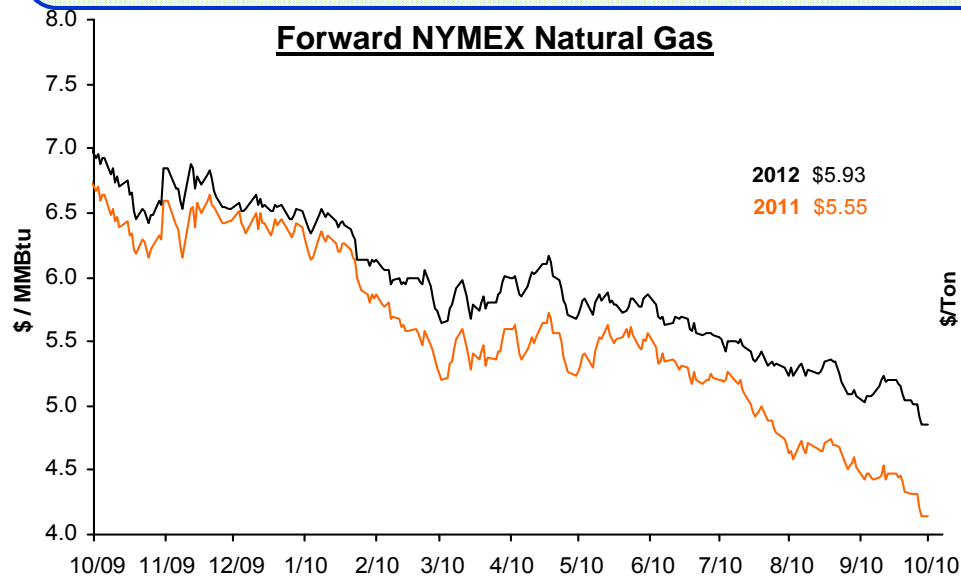
(4) Average NYMEX settled prices.

(5) 2010 information is a combination of actual prices through September 30, 2010 and market prices for the balance of the year.

(6) 2011, 2012 and 2013 are forward market prices as of September 30, 2010.

Market Price Snapshot

Rolling 12 months, as of October 25th, 2010. Source: OTC quotes and electronic trading system. Quotes are daily.

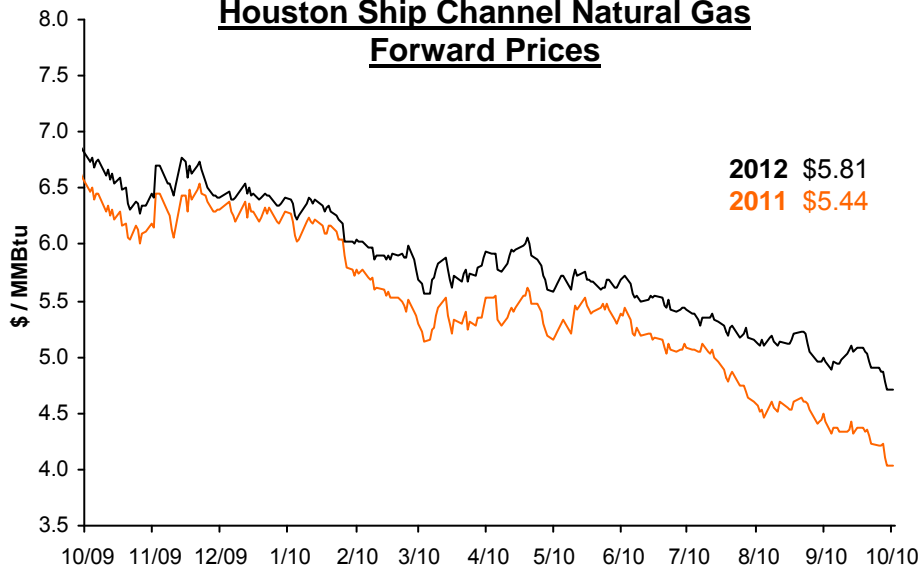


Market Price Snapshot

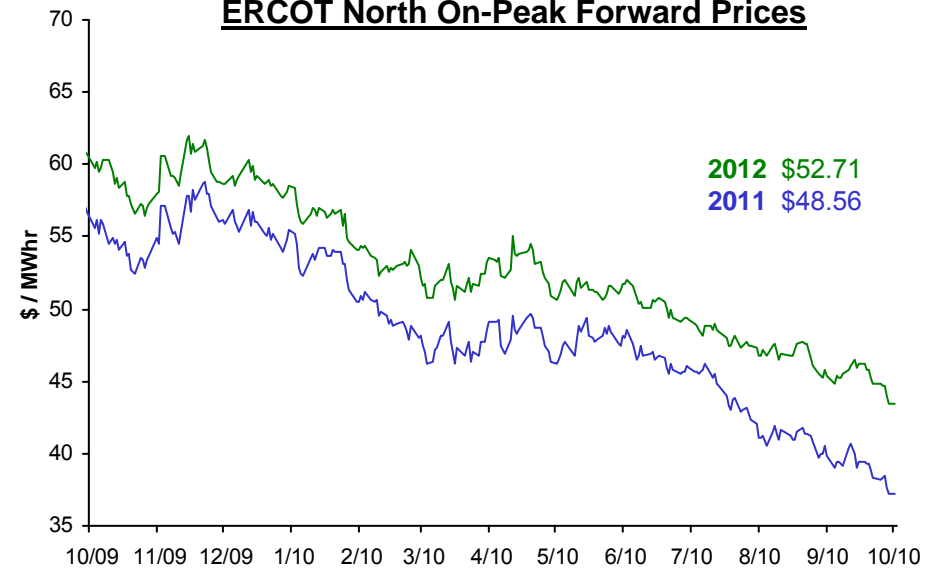
Rolling 12 months, as of October 25th, 2010. Source: OTC quotes and electronic trading system. Quotes are daily.



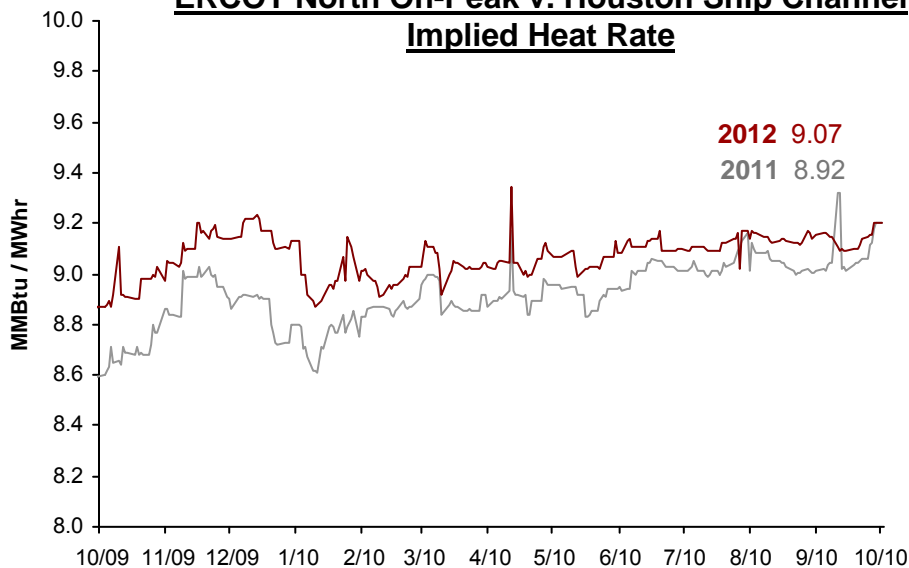
Houston Ship Channel Natural Gas Forward Prices



ERCOT North On-Peak Forward Prices

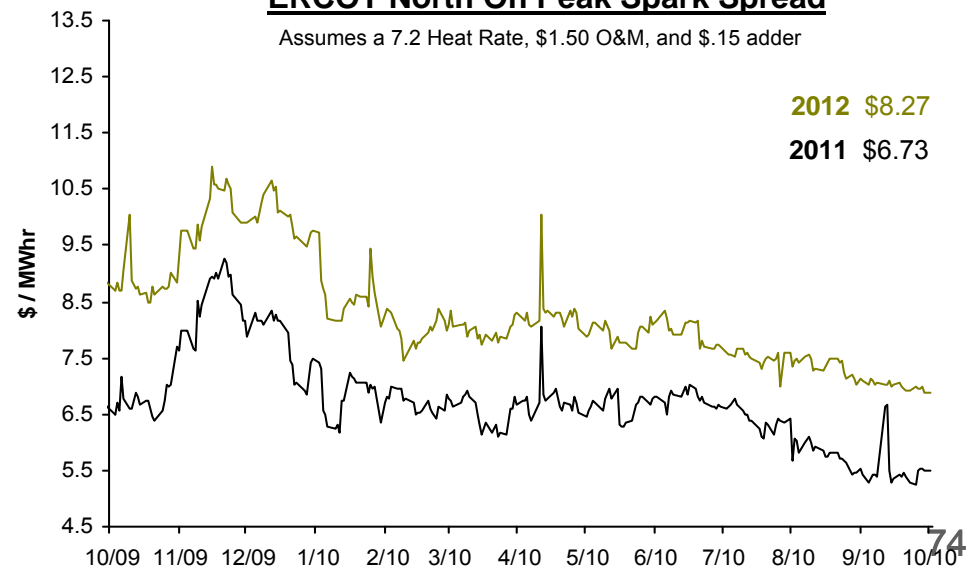


ERCOT North On-Peak v. Houston Ship Channel Implied Heat Rate



ERCOT North On Peak Spark Spread

Assumes a 7.2 Heat Rate, \$1.50 O&M, and \$.15 adder



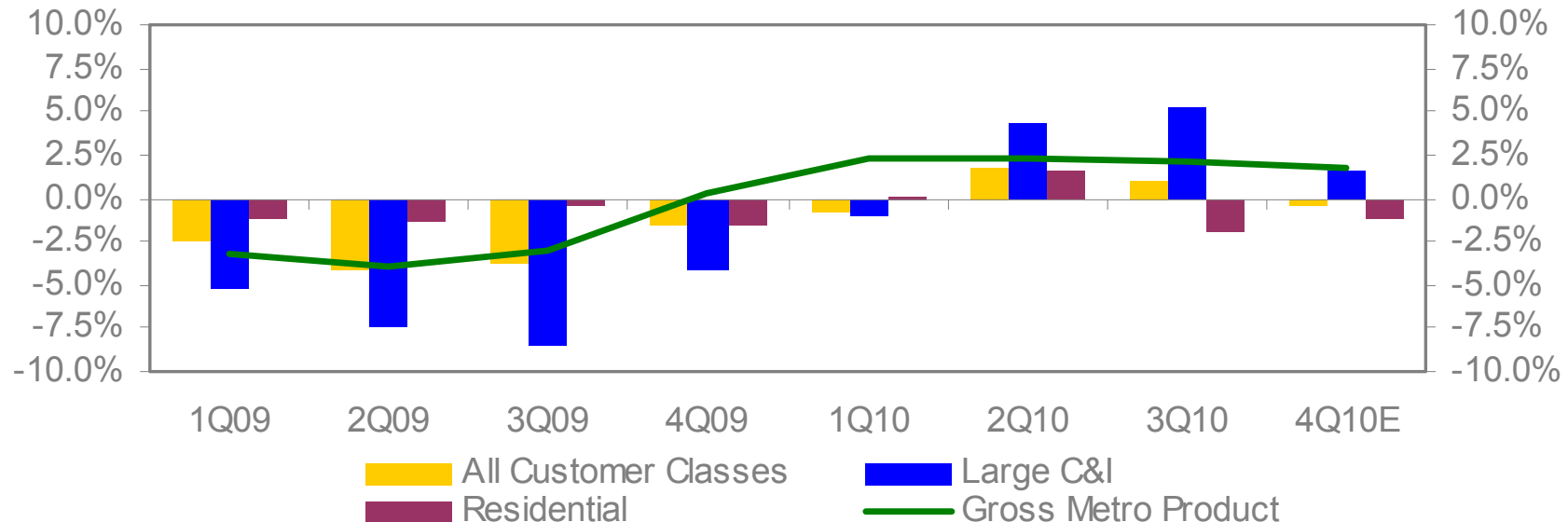
ComEd®

An Exelon Company

ComEd Load Trends



Weather-Normalized Load Year-over-Year ⁽¹⁾



2011 Outlook

- A gradually improving economy is expected in 2011 as incremental improvements in the labor market – led by hiring in the manufacturing and professional/business services sectors – build economic momentum
- 2011 will be more of a transition year than a recovery year as the inventory and fiscal stimulus boosts are fading in late 2010 to be replaced by growth in 2011 from a cautious private sector.
- Housing conditions will weigh on the economy. There is little reason for significant increases in either 2011 housing starts or home prices.

(1) Not adjusted for leap year effect.

ComEd 2010 Delivery Service Rate Case Filing Summary



	Requested Revenue Increase
(\$ in millions) ICC Docket No. 10-0467	
Rate Base: \$7,717 million ⁽¹⁾	\$179 ⁽¹⁾⁽²⁾
Capital Structure ⁽³⁾ : ROE – 11.50% / Common Equity – 47.33% / ROR – 8.99%	\$95
Pension and Post-retirement health care expenses ⁽⁴⁾	\$55
Bad debt costs (resets base level of bad debt to 2009 test year)	\$22
Other adjustments ⁽⁵⁾	\$45
Total (\$2,337 million revenue requirement) ⁽⁶⁾	\$396

Primary drivers of rate request are new plant investment, pension/retiree health care and cost of capital

- (1) Filed June 30, 2010 based on 2009 test year, including pro forma capital additions through June 2011, and certain other 2010 pro forma adjustments. Updating the depreciation and deferred tax reserves to June 2011 would reduce rate base by an estimated \$667 million and would reduce the revenue requirement by approximately \$85 million.
- (2) Includes increased depreciation expense.
- (3) Requested capital structure does not include goodwill; ICC docket 07-0566 allowed 10.3% ROE, 45.04% equity ratio and 8.36% ROR. ROE includes 0.40% adder for energy efficiency incentive.
- (4) Reflects 2010 expense levels, compared to 2007 expense levels allowed in last rate case.
- (5) Includes reductions to O&M and taxes other than income, offset by wage increases, normalization of storm costs and the Illinois Electric Distribution Tax, other O&M increases, and decreases in load.
- (6) Net of Other Revenues.

ComEd 2010 Rate Case Update



(ICC Docket No. 10-0467)

Reconciliation of ICC Staff to ComEd

ComEd Request (6/30/10)

- \$396M increase requested
- 11.50% ROE / 47.33% equity ratio
- Rate base \$7,717M
- 2009 test year with pro forma plant additions thru 6/30/11

ICC Staff Testimony (10/26/10)

- \$78M increase recommended
- 10.00% ROE / 47.11% equity ratio
- Rate base \$6,663M
- Pro forma additions and depreciation reserve thru 9/30/10

\$ millions

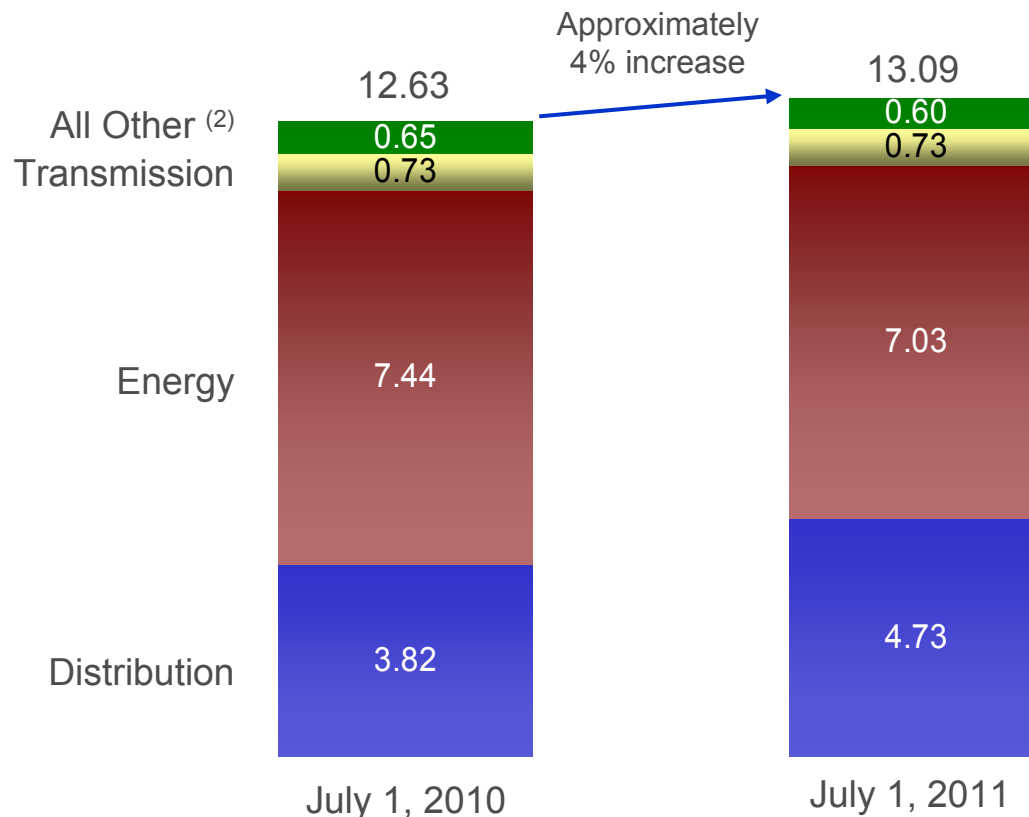
ComEd Request	\$	396
Staff Adjustments:		
Plant Additions / Depreciation Reserve		(122)
ROE / Capital Structure		(97)
Pension Asset		(33)
Incentive Compensation / Severance		(23)
Cash Working Capital		(9)
Amortization of Regulatory Assets		(8)
Pension and OPEB Expense		(4)
Other Items		(22)
ICC Staff Recommendation	\$	78

ComEd Delivery Rate Case

Residential Rate Impacts 2010 to 2011 ⁽¹⁾



Unit rates: cents / kWh



Comments

Transmission: Subject to FERC formula rate annual update

Energy: Reflects reduced PJM capacity price that PJM has published for the June 2011 – May 2012 planning period. Energy component may vary

Distribution: As proposed

Straight Fixed/Variable Rate Design: Move delivery bill from current 37% fixed/ 63% variable to 80% fixed/ 20% variable by 2013

Proposed residential rate impact of 7% will be mitigated by impact of lower capacity prices resulting in an increase of 4%

(1) Reflects change in distribution rates only. Assumes Energy, Transmission and all other components remain constant as of June 2010, except as noted above.

(2) "All Other" includes impact of riders that are applicable to residential bills.

Note: Amounts may not add due to rounding.

ComEd Delivery Rate Case Alternative Regulation (Alt Reg) Proposal



- ComEd filed a companion Alt Reg filing on August 31, 2010 proposing to recover the costs of pre-approved smart grid and other projects outside of the traditional rate case process
 - 9-month statutory process
- Proposal would allow for accelerated modernization of the distribution system, increased assistance to low-income households and the purchase of electric vehicles
- Initial series of proposed programs is \$60 million, but would create a collaborative framework for increased investments in the future implementation of ICC-approved Smart Grid investments

\$ millions	O&M	Capital
Man-hole refurbishment and cable replacement	\$15	\$30
Electric Vehicle Fleet Purchase	-	\$5
Expanded funding for low income CARE programs ⁽¹⁾	\$10	-

- The proposal includes a “flow-through mechanism” to recover capital carrying costs and incremental O&M, as incurred
- Assured savings to customers – \$2 million on capped O&M costs for program costs (excluding CARE)
- Includes an incentive/penalty mechanism for performance above or under budget

Alt Reg Proposal is permitted under section 9-244 of the IL Public Utilities Act

(1) CARE = Customers' Affordable Reliable Energy. Total CARE amount for two-year proposal is \$20 million.

ComEd Delivery Service Rate Case Tentative Schedule



- Delivery Service Rate Case Filed – June 30, 2010
- Alt Reg Proposal Filed – August 31, 2010
- Staff and Intervenor Direct Testimony – October 26, 2010 (Rate Case), November 19 (Alt Reg)
- ComEd Rebuttal Testimony – November 22 (Rate Case), December 8 (Alt Reg)
- Staff and Intervenor Rebuttal Testimony - December 23, 2010 (Rate Case), December 30 (Alt Reg)
- ComEd Surrebuttal Testimony – January 3, 2011 (Rate Case), January 5 (Alt Reg)
- Hearings – January 2011
- Administrative Law Judge Order – March 31, 2011
- Final Order Expected – May 2011
- New Rates Effective – June 2011

ComEd Rate Base Growth

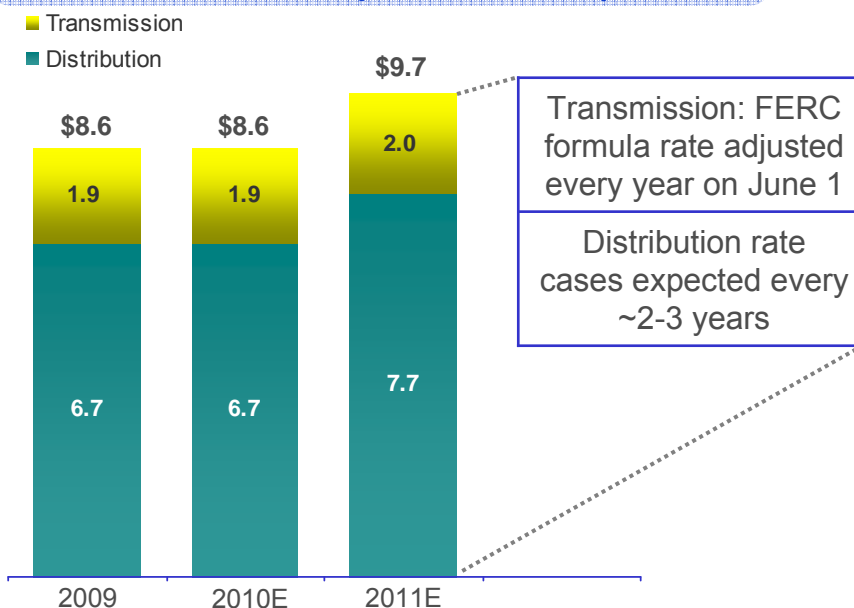


Recent Rate Cases

ELECTRIC DISTRIBUTION	Prior Rate Case	Current Filing 6/30/2010
Rates Effective	October 1, 2008	June 1, 2011
Test Year	2006 pro forma	2009 pro forma
Rate Base	\$6,694 million	\$7,717 million
ROE	10.3%	11.5%
Equity %	45.04%	47.33%

TRANSMISSION	FERC Formula rate
Rates Effective	June 1, 2010
Test Year	2009 pro forma
Rate Base	\$1,949 million
ROE	11.5%
Equity %	56%

Rate Base in Rates End of Year (\$ in billions) ⁽¹⁾



	2009	Target
Equity	~46%	~45%
Earned ROE	8.5%	≥10%

ComEd executing on regulatory recovery plan

(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. The Court remanded the case to the ICC. For the 2007 rate case, the Court's ruling would reduce the \$6,694 million rate base by ~\$500 - \$670 million resulting in a revenue reduction between \$57 and \$77 million. For the current rate case, updating the depreciation and deferred tax reserves to June 2011 would reduce the \$7,717 million rate base by an estimated \$667 million and would reduce the revenue requirement by approximately \$85 million.

Note: Amounts may not add due to rounding.

Illinois Power Agency (IPA) RFP Procurement

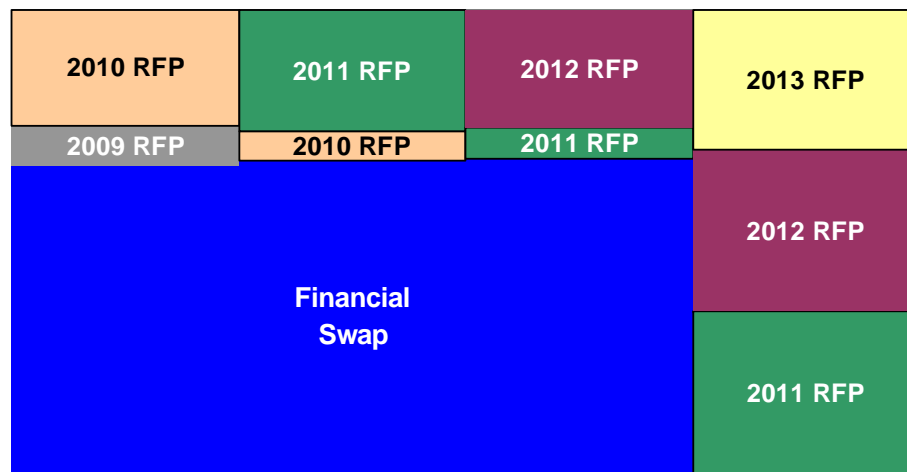


➤ Long-Term REC Procurement Scheduled for November 2010

- 1.4 million MWh of renewable resources annually beginning in June 2012 under 20-year contracts
- RFP bids due on November 19th with contracts signed early December

➤ Spring 2011 Procurement Plan

- IPA proposal submitted with a number of issues to be resolved. Final ICC decision expected by year end
- Provisions that appear likely to continue:
 - Annual energy procurements over a three-year time frame
 - Target a 35%/35%/30% ladder procurement approach
- Other items being discussed:
 - Additional energy efficiency, demand response purchases
 - More long-term contracts for renewables



Financial Swap Agreement with ExGen

(ATC baseload energy only – notional quantity 3,000 MW)

<u>Term</u>	<u>Fixed Price</u>
6/1/10-12/31/10	\$50.15/MWh
1/1/11-12/31/11	\$51.26
1/1/12-12/31/12	\$52.37
1/1/13-5/31/13	\$53.48

June 2010 June 2011 June 2012 June 2013 June 2014

Note: Chart is for illustrative purposes only.
REC = Renewable Energy Credit; RFP = request for proposal

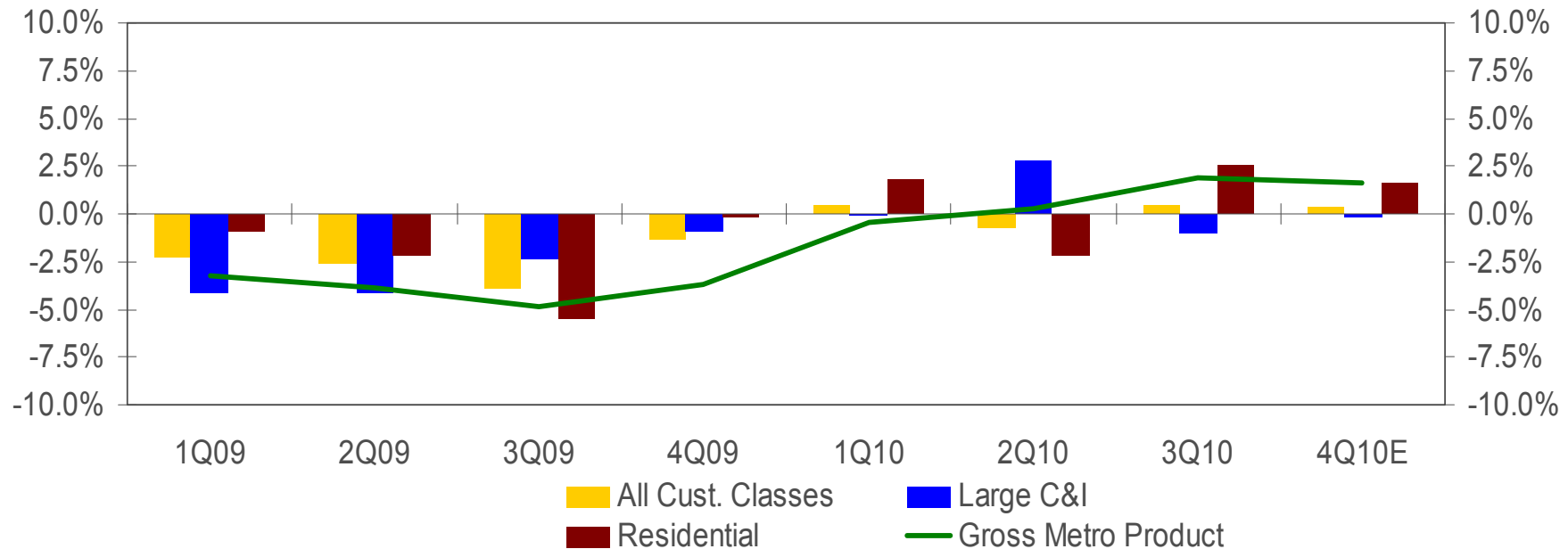


An Exelon Company

PECO Load Trends



Weather-Normalized Load Year-over-Year ⁽¹⁾



2011 Outlook

- Economically driven load growth will be significantly offset by mandated energy efficiency initiatives.
- 2011 GMP will show a gradual improvement over 2010, but not a robust recovery, where both non-manufacturing employment and income see growth of less than 1.5%
- Manufacturing employment is expected to remain nearly flat
- The housing market will offer neither a real drag nor a real boost in 2011

(1) Not adjusted for leap year effect

Note: C&I = Commercial & Industrial

PECO – Electric & Gas Distribution Rate Case Settlements



- Joint settlement filed with the PAPUC on August 31, 2010 for both electric and gas rate cases
- Settlements are subject to administrative law judges review and PAPUC approval by mid-December 2010

Rate Case Details	Electric	Gas
Docket #	R-2010-2161575	R-2010-2161592
Revenue Requirement Increase in Settlement ⁽¹⁾	\$225 million	\$20 million
2011 Distribution Price Increase as % of Overall Customer Bill for Residential customers	~7%	~4%

New rates scheduled to go into effect on January 1, 2011

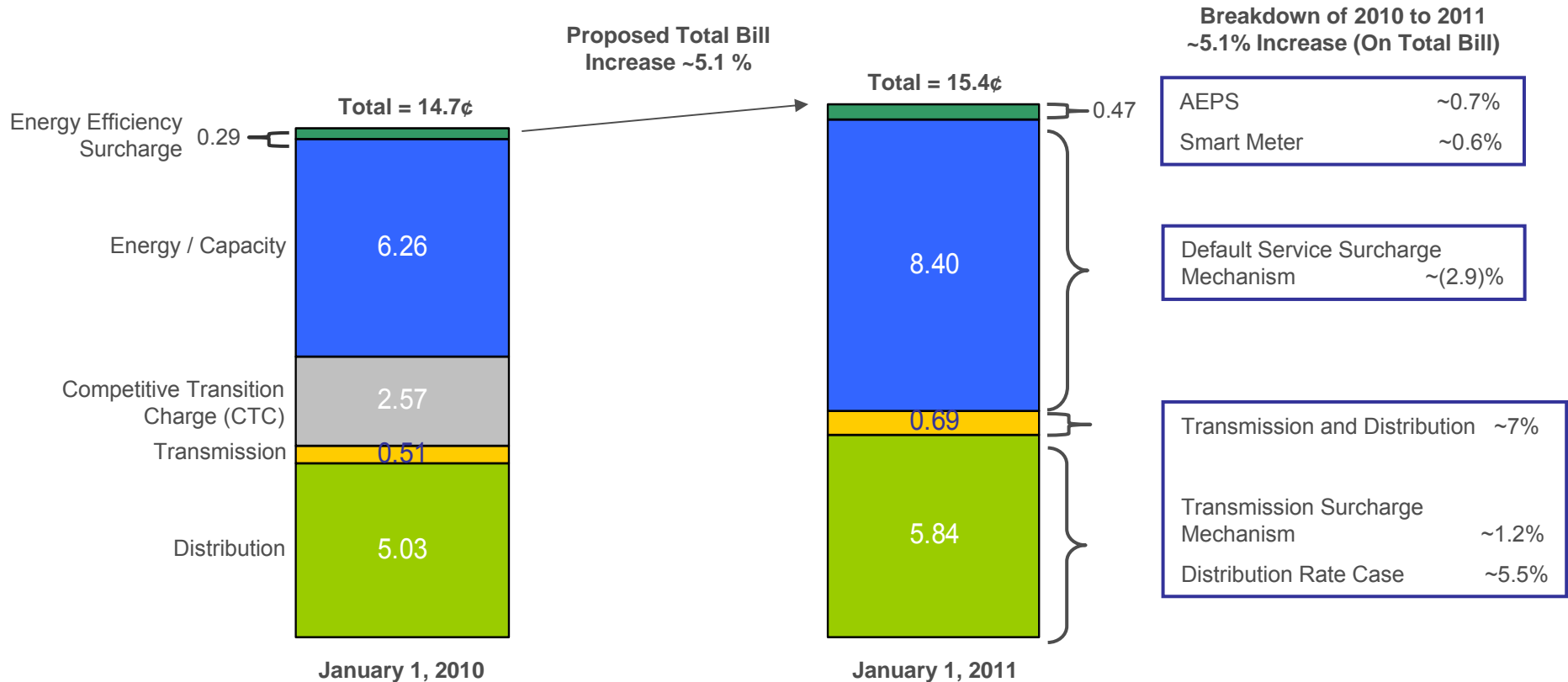
(1) Settlements are on an overall revenue requirement basis, meaning no details are provided for allowed ROE, rate base or capital structure.

Note: Electric and gas rate case filings available on Pennsylvania Public Utility Commission (PAPUC) website (www.puc.state.pa.us) or www.peco.com/know.

PECO Electric Residential Rate Increases 2010 to 2011



Unit Rates (¢/kWh)



Notes:

- Rates effective January 1, 2010 include Act 129 Energy Efficiency surcharge of 2%.
- Represents average of all residential rates including the effect of discounted rates provided to low income customers.
- AEPS = Alternative Electric Portfolio Standard

PECO Executing on Transition Plan



Recent Rate Cases ⁽¹⁾

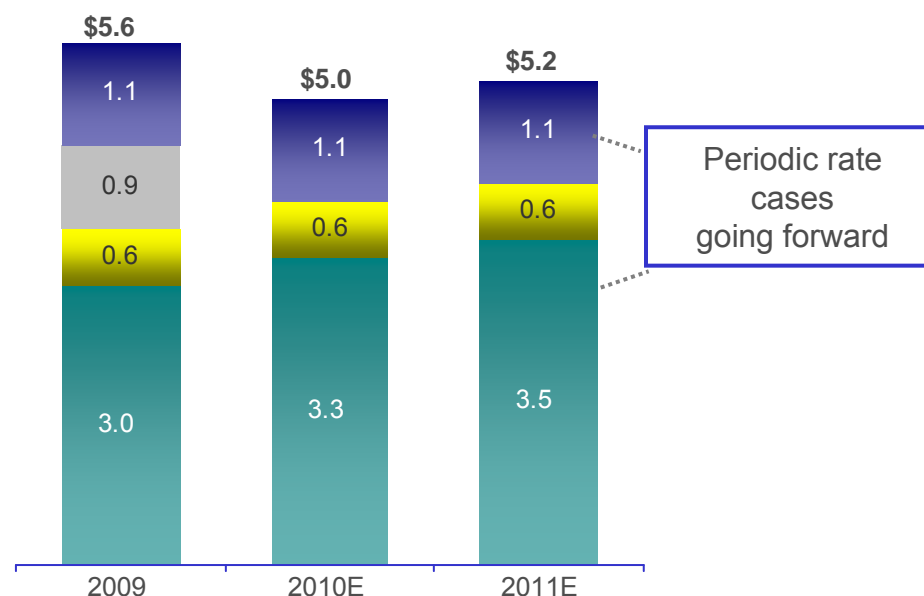
ELECTRIC DISTRIBUTION	Filing 3/31/2010
Rates Effective	January 1, 2011
Test Year	2010
Revenue Increase	\$225 million

GAS DELIVERY	Filing 3/31/2010
Rates Effective	January 1, 2011
Test Year	2010
Revenue Increase	\$20 million

TRANSMISSION	Stated rate; no recent rate cases
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Rate Base in Rates End of Year Balance (\$ in billions) ⁽¹⁾

■ Electric Distribution ■ Electric Transmission
■ CTC ■ Gas



	2009	Target
Equity ⁽¹⁾	53%	51-53%
Earned ROE	14.8%	≥10%

PECO is managing through its transition period and is positioned for continued strong financial performance post-2010

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

PECO Procurement



PECO Procurement Plan ⁽¹⁾

Customer Class	Products
Residential	✓75% full requirements ✓20% block energy ✓5% energy only spot
Small Commercial (peak demand <100 kW)	✓90% full requirements ✓10% full requirements spot
Medium Commercial (peak demand >100 kW but ≤ 500 kW)	✓85% full requirements ✓15% full requirements spot
Large Commercial & Industrial (peak demand >500 kW)	✓Fixed-priced full requirements ⁽³⁾ ✓Hourly full requirements

2011 Supply Procured

Residential

- ✓ June '09 RFP average price of \$88.61/MWh ⁽²⁾
- ✓ Sept '09 RFP average price of \$79.96/MWh ⁽²⁾
- ✓ May '10 RFP average price of \$69.38/MWh ⁽²⁾
- ✓ Sept '10 RFP average price of \$66.83/MWh ⁽²⁾

Small Commercial

- ✓ Sept '09 / May '10 RFP aggregate result \$77.65/MWh ⁽²⁾
- ✓ Sept '10 RFP average price of \$70.82/MWh ⁽²⁾

Medium Commercial

- ✓ Sept '09 / May '10 RFP aggregate result \$77.89/MWh ⁽²⁾
- ✓ Sept '10 RFP average price of \$70.36/MWh ⁽²⁾

Large Commercial and Industrial

- ✓ Large Fixed May '10 RFP - average price of \$77.55/MWh ⁽²⁾⁽³⁾
- ✓ Large Hourly Sept '10 RFP - average price of \$4.83/MWh ⁽⁴⁾

2011 supply procured, two procurement events per year moving forward

(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 RFP.

(3) For Large C&I customers who previously opted to participate in the 2011 fixed-priced full requirements product.

(4) Large Hourly price includes ancillary services and supplier-provided AEPS cost.

PECO Smart Grid/Smart Meter



Background

- ACT 129 required Smart Meter technology in 15 years
- DOE \$200M assistance agreement completed in May
 - Accelerated Smart Meter deployment to 10 years
- PA PUC Smart Meter Plan approval received in April
- PECO to spend \$650M in total (including stimulus grant)
 - \$550M for Smart Meter
 - \$100M for Smart Grid
- Surcharge mechanism with 10% allowed return

Key Accomplishments

- Letters of Intent with vendors for Automated Metering Infrastructure (AMI) communications network, smart meters and meter installation; projects underway
- Significant field work on Smart Grid projects to enhance reliability in progress
- Implemented DOE compliance reporting
- Sub-applicant agreements signed with Drexel and Liberty Partners
- Dynamic Pricing Plan filing in progress

Near-Term Focus

- Complete limited test of our Smart Meter and communications system technologies
- Continue to integrate supporting AMI systems (e.g., meter data management, billing, middleware)
- Continue Smart Grid Distribution Automation and Intelligent Substations Implementation
- Complete Distribution Management and Geographical Information System Vendor Selections
- Finalize communications and customer experience plan

2010- 2013 Projected Expenditures

(\$ millions pre-tax)	2010	2011	2012	2013	Total
Act 129 Smart Meter Expanded Initial Deployment ⁽¹⁾	\$ 39	\$ 86	\$ 116	\$ 59	\$ 300
Smart Grid Stimulus Case	40	45	15		100
Total Stimulus Case	79	131	131	59	400
Stimulus Grant	(40)	(66)	(66)	(30)	(200)
Total Expenditures net of Stimulus grant	\$ 40	\$ 66	\$ 66	\$ 30	\$ 200

(1) Includes approximately \$20 million/yr of O&M in 2010-2012.

Data contained in this slide is rounded.

2009 GAAP EPS Reconciliation



<u>2009 GAAP EPS Reconciliation</u> ⁽¹⁾	<u>ExGen</u>	<u>ComEd</u>	<u>PECO</u>	<u>Other</u>	<u>Exelon</u>
2009 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	\$3.16	\$0.54	\$0.54	\$(0.12)	\$4.12
Mark-to-market adjustments from economic hedging activities	0.16	-	-	-	0.16
2007 Illinois electric rate settlement	(0.09)	(0.01)	-	-	(0.10)
Unrealized gains related to nuclear decommissioning trust funds	0.19	-	-	-	0.19
Decommissioning obligation reduction	0.05	-	-	-	0.05
City of Chicago settlement with ComEd	-	(0.01)	-	-	(0.01)
NRG Energy, Inc. acquisition costs	-	-	-	(0.03)	(0.03)
Impairment of certain generating assets	(0.20)	-	-	-	(0.20)
2009 restructuring charges	(0.01)	(0.02)	(0.00)	-	(0.03)
Non-cash remeasurement of income tax uncertainties and reassessment of state deferred income taxes	0.06	0.06	-	(0.02)	0.10
Costs associated with early debt retirements	(0.07)	-	-	(0.04)	(0.11)
Retirement of fossil generating units	(0.05)	-	-	-	(0.05)
FY 2009 GAAP Earnings (Loss) Per Share	\$3.21	\$0.56	\$0.53	\$(0.21)	\$4.09

(1) All amounts shown are per Exelon share and represent contributions to Exelon's EPS.

Note: Amounts may not add due to rounding.

2010 Earnings Outlook



- **Exelon's 2010 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
 - Costs associated with the 2007 Illinois electric rate settlement agreement
 - Costs associated with ComEd's 2007 settlement with the City of Chicago
 - Costs associated with the retirement of fossil generating units
 - Non-cash charge resulting from passage of Federal health care legislation
 - Non-cash remeasurement of income tax uncertainties
 - External costs associated with Exelon's proposed acquisition of John Deere Renewables
 - Impairment of certain emission allowances
 - Other unusual items
 - Significant future changes to GAAP
- **Operating earnings guidance assumes normal weather for remainder of the year**
- **Operating O&M target excludes the following items:**
 - Exelon Generation: Decommissioning accretion expense
 - ComEd and PECO: Impact of regulatory riders

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