

# **Exelon Corporation Investor Meetings**

**October 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 Second 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 12 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.

# Leader in the U.S. Electric Power Industry

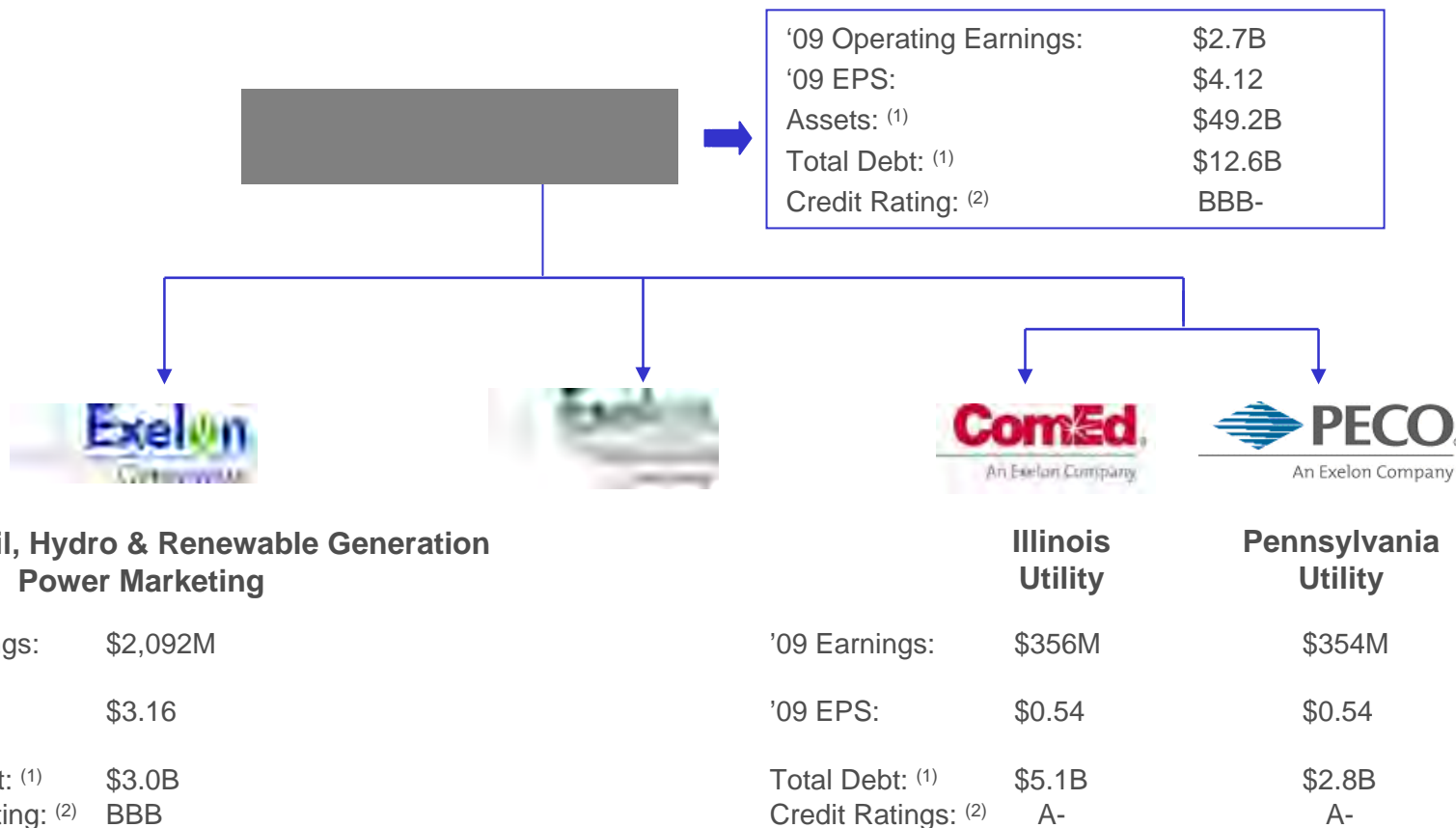


- ✓ **Among the leading market caps in the sector at ~\$28 billion, investment grade balance sheet**
- ✓ **Experienced management team with track record of creating and returning shareholder value**
  - Exelon formed through combination of ComEd and PECO Energy in 2000
  - Total shareholder return <sup>(1)</sup> of 102% since October 2000, compared to 72% for the Philadelphia Utility Index and a negative 1% for the S&P 500 Index
  - \$2.10 dividend per share; ~5% dividend yield – among the highest yields in the sector
- ✓ **Largest merchant generator of electricity in the U.S.**
  - Ownership interest in 19 operating nuclear reactors
  - Largest nuclear operator in U.S. with 18% of nuclear output; third largest in the world
  - Industry-leading capacity factors, with seven consecutive years over 93%, and generating cost among the lowest for nuclear fleets in the U.S.
  - Geographically well-situated in competitive markets and part of PJM, the largest RTO
- ✓ **Well positioned in the industry for upside from environmental regulation, including recent acquisition of John Deere Renewables, a leading operator and developer of wind power**
- ✓ **Two high-performing delivery companies – ComEd in Chicago and PECO in Philadelphia**

**Exelon's asset base, operational performance and presence in competitive markets enable us to capture and create value**

(1) Total shareholder return from October 20, 2000 through September 24, 2010.  
Note: RTO = Regional Transmission Organization

# The Exelon Companies



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

(1) As of December 31, 2009.

(2) Standard & Poor's senior unsecured debt ratings for Exelon and Generation and senior secured debt ratings for ComEd and PECO as of September 30, 2010.

# Multi-Regional, Diverse Company



## Total Capacity

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

**ComEd**

An Exelon Company

Electricity Customers: 3.8M

**PECO**

An Exelon Company

Electricity Customers: 1.6M  
Gas Customers: 0.5M

## New England Capacity

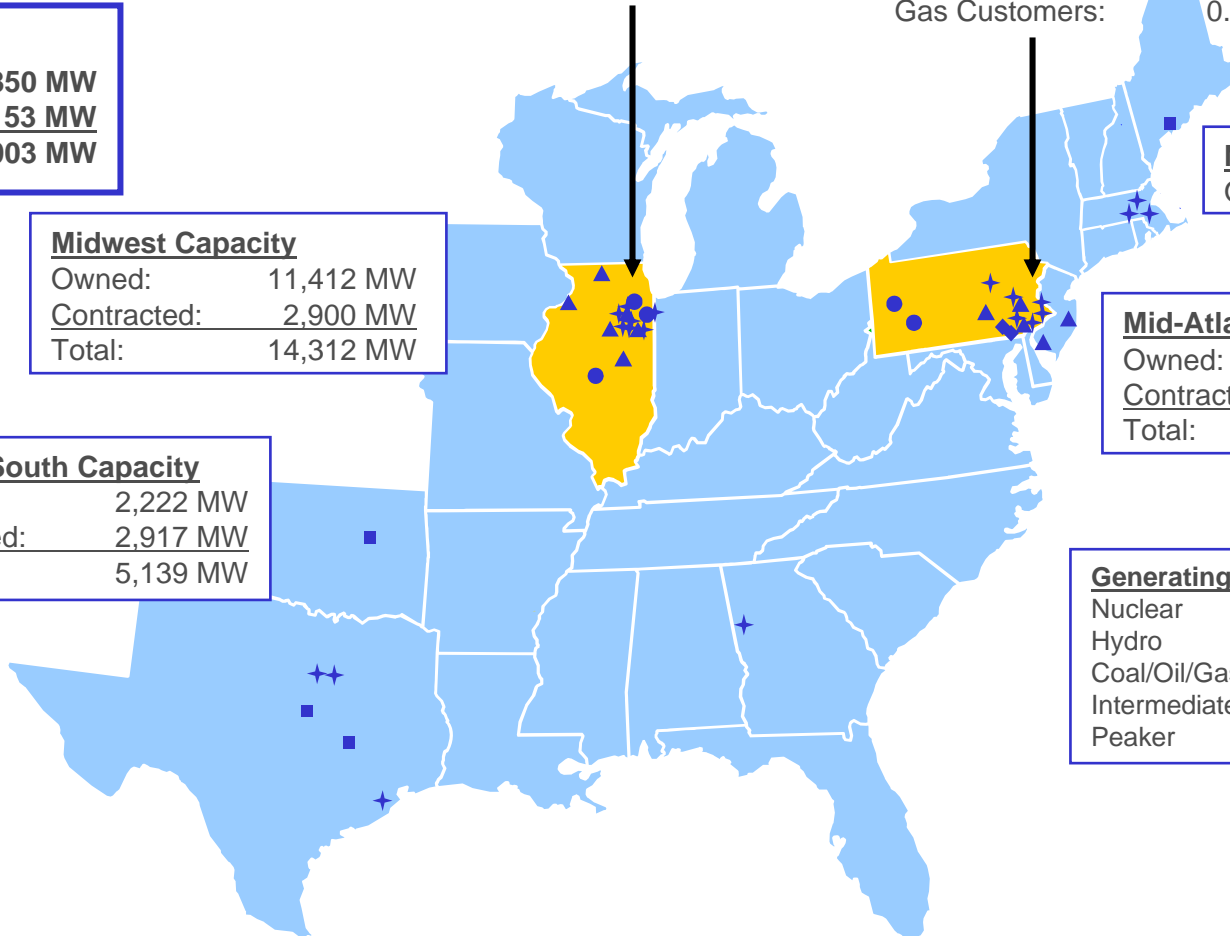
Owned: 182 MW

## Mid-Atlantic Capacity

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

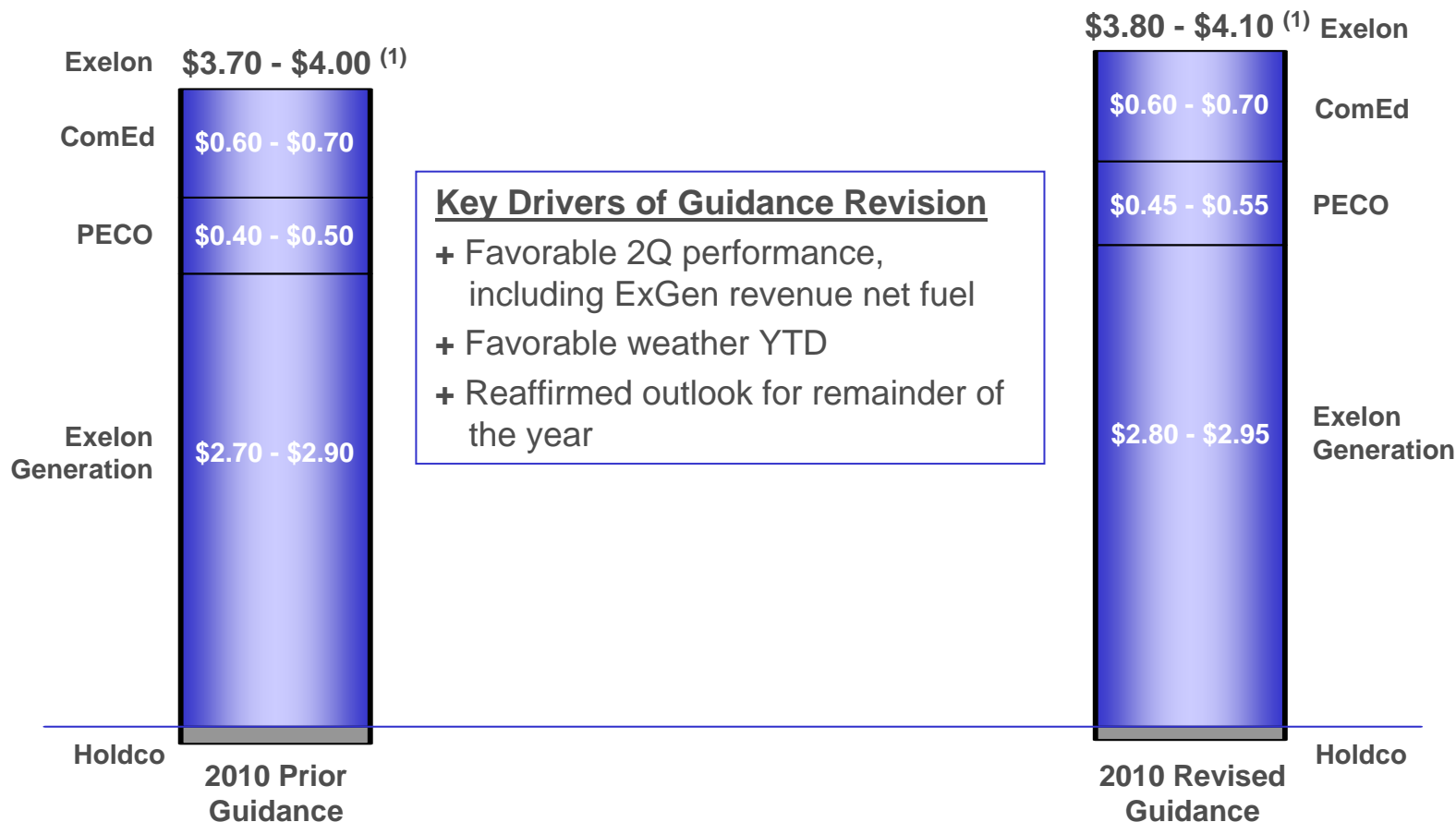
## Generating Plants

Nuclear ▲  
Hydro ◆  
Coal/Oil/Gas Base-load ●  
Intermediate ■  
Peaker ✦



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.

# 2010 Operating Earnings Guidance






**After the second quarter, we revised 2010 operating earnings guidance to \$3.80-\$4.10 per share <sup>(1)</sup>**

(1) We raised 2010 earnings guidance on July 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 the Appendix for a reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS.

# 2010 Projected Sources and Uses of Cash



(\$ millions)

				Exelon <sup>(9)</sup>
<b>Beginning Cash Balance <sup>(1)</sup></b>				<b>\$1,050</b>
Cash Flow from Operations <sup>(1)(2)</sup>	1,100	1,025	2,400	4,575
CapEx (excluding Nuclear Fuel, Nuclear Upgrades and Solar Project, Utility Growth CapEx)	(700)	(400)	(800)	(1,950)
Nuclear Fuel	n/a	n/a	(850)	(850)
Dividend <sup>(3)</sup>				(1,400)
Nuclear Upgrades and Solar Project	n/a	n/a	(325)	(325)
Utility Growth CapEx <sup>(4)</sup>	(225)	(100)	n/a	(325)
Net Financing (excluding Dividend):				
Planned Debt Issuances <sup>(5)(6)</sup>	500	--	250	750
Planned Debt Retirements <sup>(7)</sup>	(225)	(400)	--	(1,025)
Other <sup>(8)</sup>	(50)	125	--	0
<b>Ending Cash Balance <sup>(1)</sup></b>				<b>\$500</b>

Note: The information on this slide is the same as disclosed on July 22, 2010 and has not been updated to reflect any changes that may have occurred since that date, such as ComEd's \$500 million bond sale on July 27, 2010 and Exelon Generation's \$900 million bond sale on September 27, 2010.

(1) Excludes counterparty collateral activity.

(2) Cash Flow from Operations primarily includes net cash flows provided by operating activities and net cash flows used in investing activities other than capital expenditures. Cash Flow from Operations for PECO and Exelon includes \$550 million for competitive transition charges.

(3) Assumes 2010 dividend of \$2.10/share. Dividends are subject to declaration by the Board of Directors.

(4) Represents new business and smart grid/smart meter investment.

(5) Excludes Exelon Generation's \$212 million and ComEd's \$191 million of tax-exempt bonds that are backed by letters of credit. Excludes PECO's \$225 million Accounts Receivable (A/R) Agreement with Bank of Tokyo. PECO's A/R Agreement was extended in accordance with its terms until September 6, 2011.

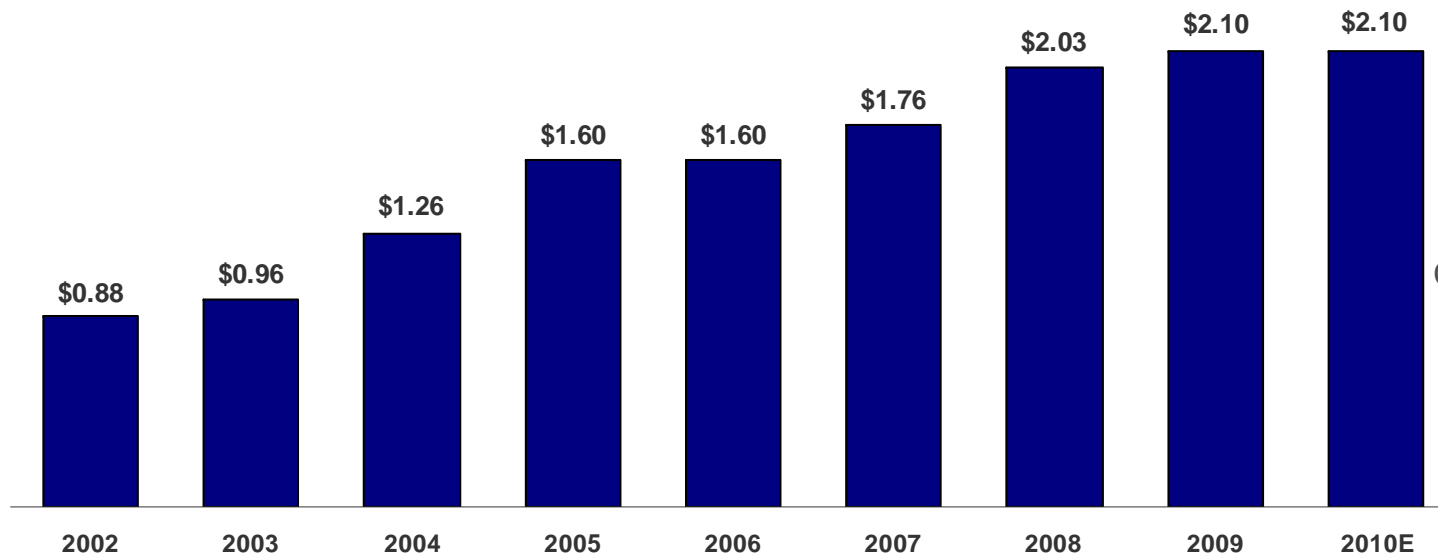
(6) Exelon Generation's financing includes \$250 million of debt to refinance a portion of Exelon Corp's \$400 million maturity.

(7) Excludes Exelon Generation's and ComEd's tax-exempt bonds. PECO's planned debt retirement of \$400 million represents the final retirement of the PECO Energy Transition Trust.

(8) "Other" includes PECO Parent Receivable, proceeds from options and expected changes in short-term debt.

(9) Includes cash flow activity from Holding Company, eliminations, and other corporate entities.

# Exelon's Dividend Track Record



Dividend Yield <sup>(1)</sup>  
 Exelon: 4.9%  
 Competitive Integrateds: 4.3%  
 Regulated Integrateds: 4.7%

**Exelon has a proven track record of maintaining its dividend and currently offers one of the highest yields among its peers**

Note: Chart represents dividends per share paid by Exelon for 2002-2009 and expected dividend for 2010, which is subject to Board approval.

(1) Dividend yield as of September 24, 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.



# Organic Growth Opportunities



## Nuclear Upgrades

**1,300–1,500 MW of new Exelon nuclear capacity by 2017, the equivalent of a new nuclear plant at roughly half the cost of a new plant and no incremental operating costs**

## Transmission

**Leveraging transmission expertise through utility companies ComEd and PECO, Exelon Transmission Company and Exelon Generation**

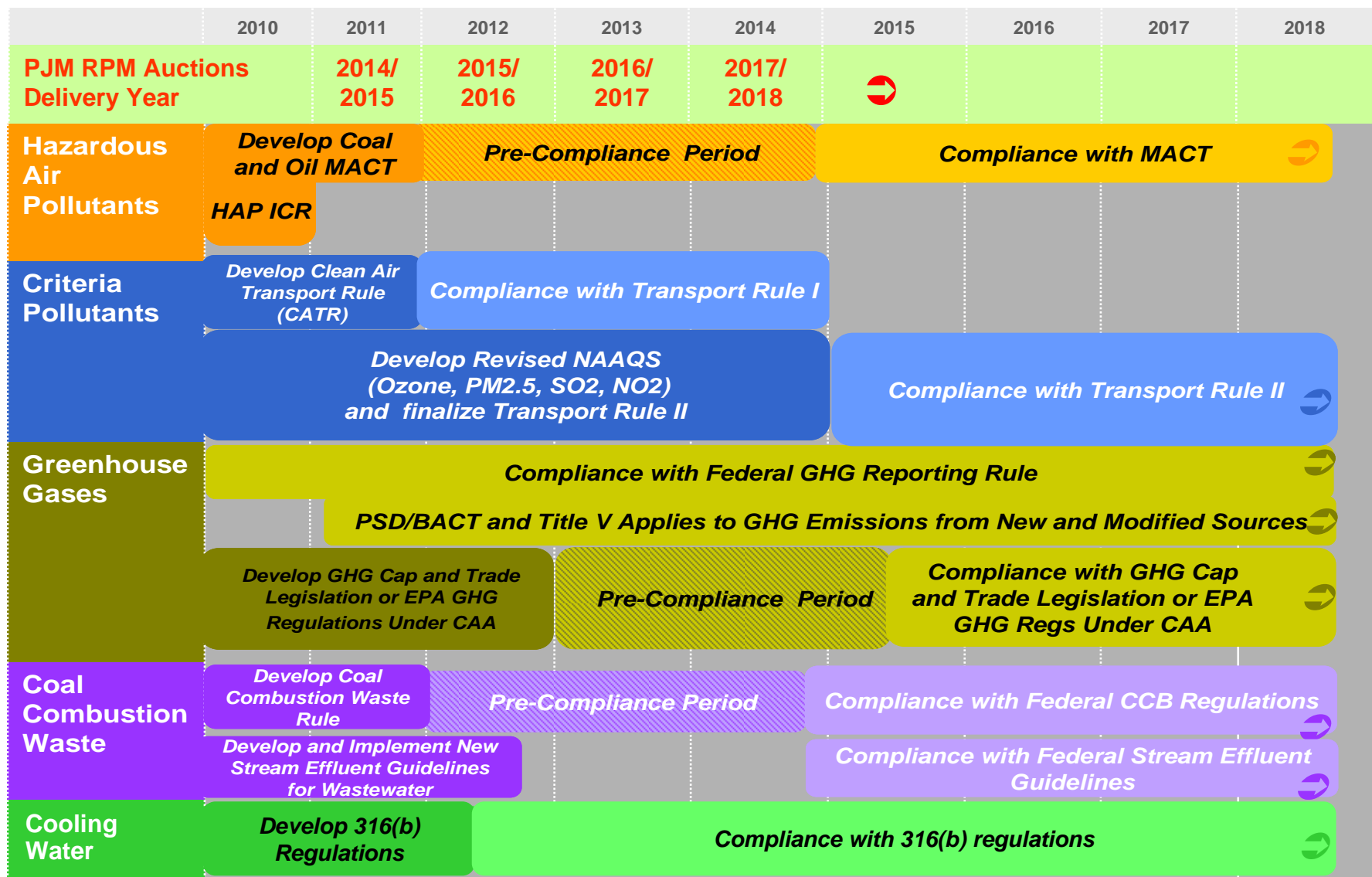
## Smart Grid

**Industry-leading energy efficiency and smart grid investments over the coming years with a regulated return**

## Rate Cases

**Executing regulatory recovery plans at ComEd and PECO with three active distribution rate cases (the two PECO rate cases have been settled, pending PAPUC approval)**

# EPA Regulations – Market Implications Leading Up to 2012 Compliance

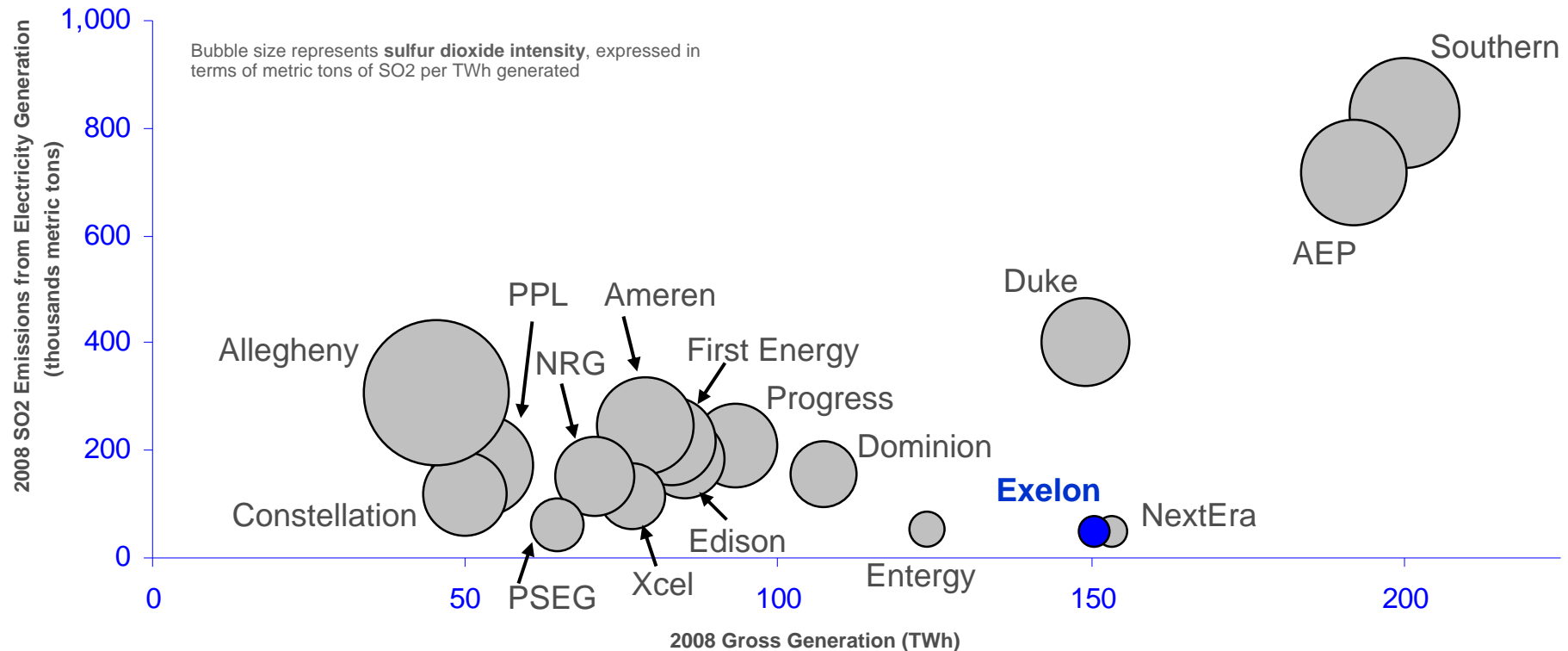


Notes: Reliability Pricing Model (RPM) auctions take place annually in May.  
For definition of the EPA regulations referred to on this slide, please see the EPA's Terms of Environment (<http://www.epa.gov/OCEPAterms/>).

# 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**

# EPA Clean Air Standards Will Not Threaten Electric System Reliability



- M.J. Bradley and Analysis Group report <sup>(1)</sup> in August 2010 concluded industry is well-positioned to respond to proposed standards
  - System has >100 GWs 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**

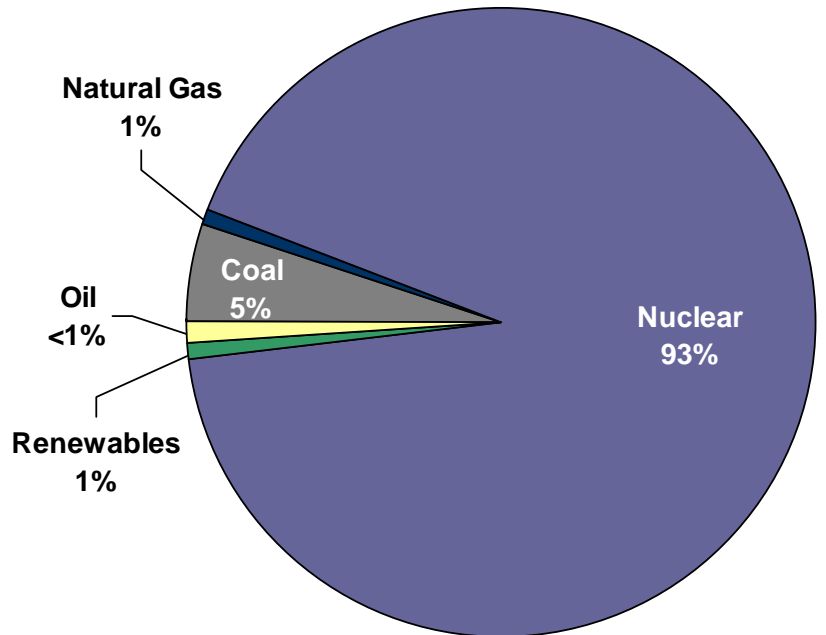
(1) M.J. Bradley & Associates, LLC and Analysis Group. 2010. *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability*.

**Exelon<sup>®</sup>**

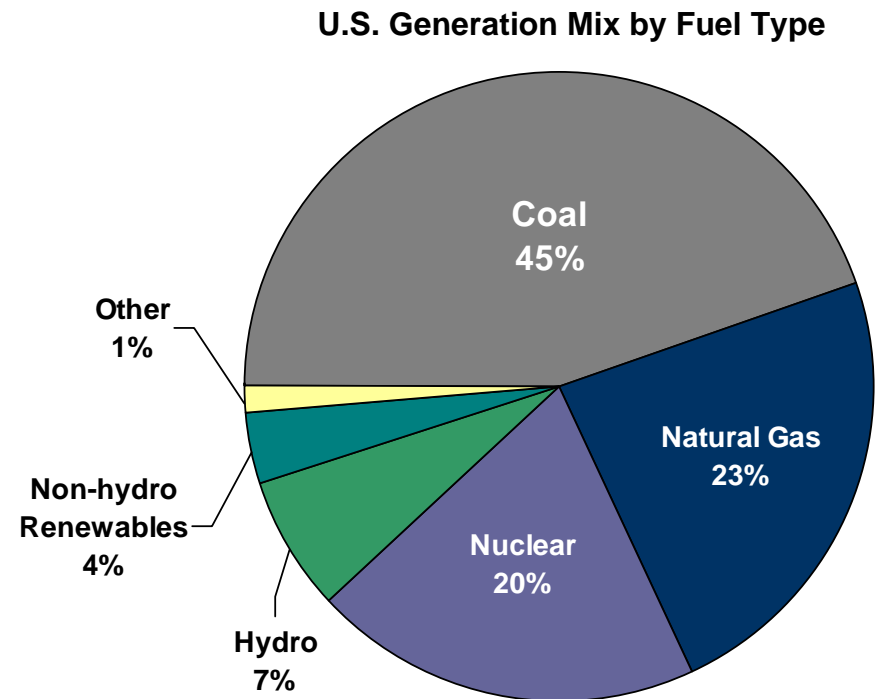
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Generation

# Exelon Generation Portfolio – Largest U.S. Nuclear Generator



Exelon Generation's Portfolio by Fuel Type <sup>(1)</sup>



**Exelon Generation has top quartile performance in capacity factors and generating cost among nuclear fleets in U.S.**

(1) 2009 Exelon Generation – ownership equity. Does not include wind portfolio acquired from John Deere Renewables.

# 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 <sup>(1)</sup>		Project Duration	Estimated Internal Rate of Return
<b>Megawatt Recovery and Component Upgrades</b>				
237–266 MW	\$800M	<ul style="list-style-type: none"> <li>Replacement of major components in the plant occur in the normal life cycle process – with newer technology, replacements result in increased efficiency</li> <li>Equipment includes generators, turbines, motors and transformers</li> <li>Megawatt Recovery and Component Upgrades must conform to NRC standards, but do not require additional NRC approval</li> </ul>	3-4 years	11-13%
<b>MUR (Measurement Uncertainty Recapture)</b>				
187–234 MW	\$300M	<ul style="list-style-type: none"> <li>Through the use of advanced techniques and more precise instrumentation, reactor power can be more accurately calculated</li> <li>Can achieve up to 1.7% additional output</li> <li>Requires NRC approval</li> </ul>	2 years	14-16%
<b>EPU (Extended Power Upgrade)</b>				
899–1,016 MW	\$2,400M	<ul style="list-style-type: none"> <li>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</li> <li>Requires NRC approval</li> </ul>	3 - 6 years	11-14%
~1,300–1,500 MW	\$3,500M			

**Refined scenario analysis highlights that upgrades continue to be economic**

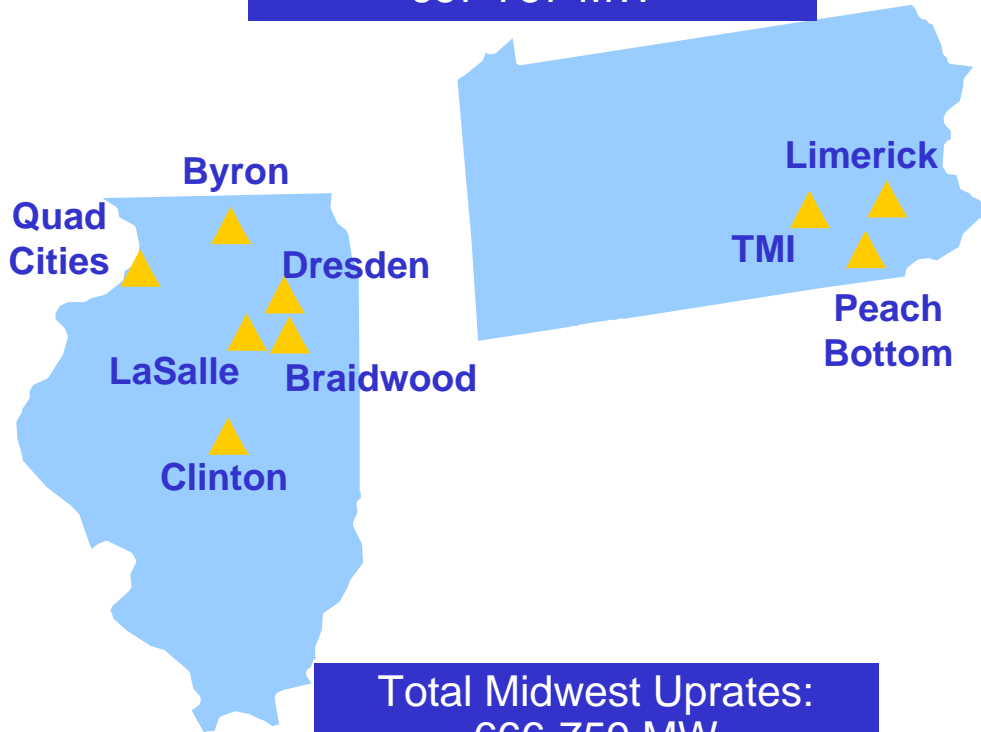
(1) In 2007 dollars. Overnight costs do not include financing costs or cost escalation.



# Multi-Regional Nuclear Uprate Program



**Total Mid-Atlantic Uprates:  
657-757 MW**



**Total Midwest Uprates:  
666-759 MW**

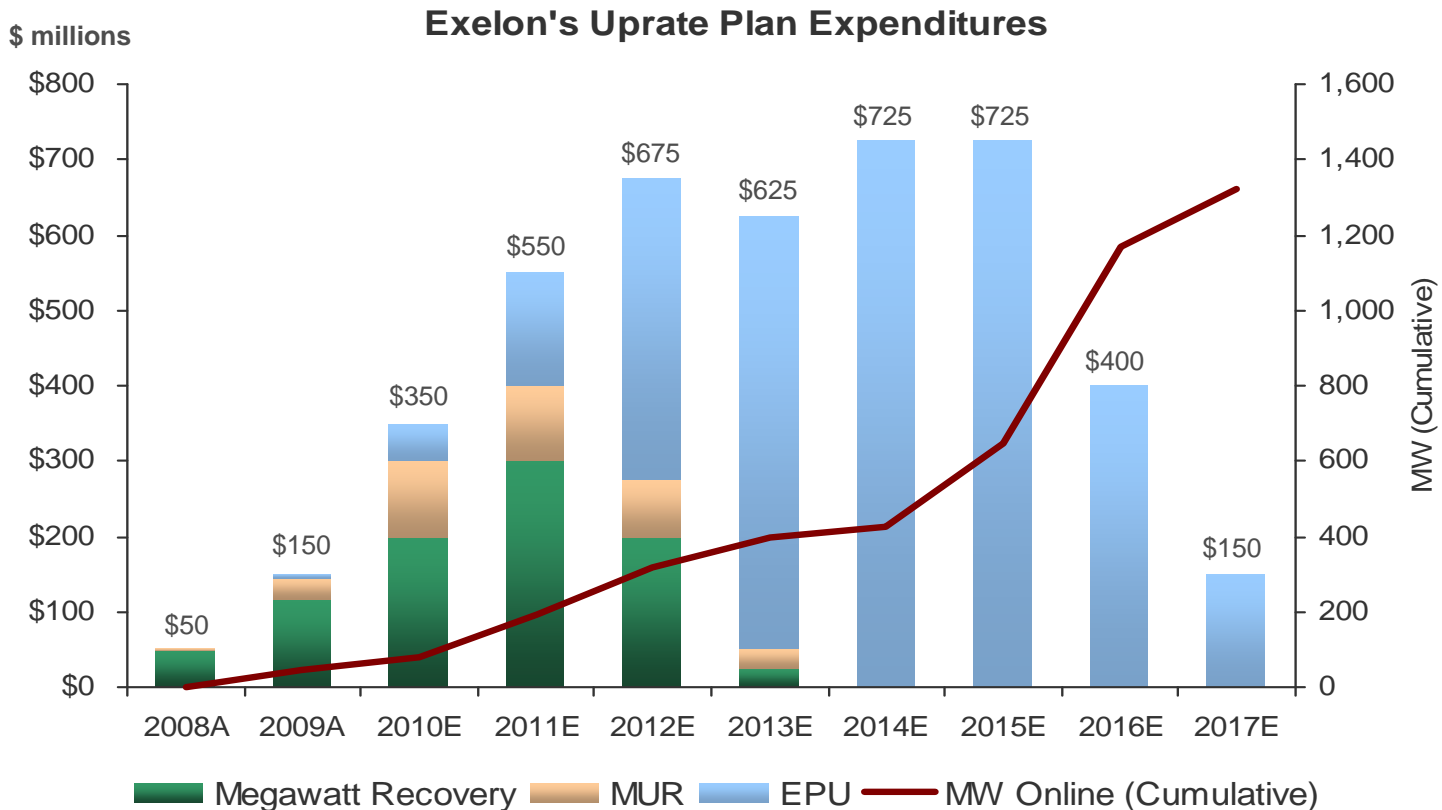
**Executing uprate projects across our  
geographically diverse nuclear fleet**

Station	Base Case MW	Max Potential MW	MW Online to Date	Year of Full Operation by Unit
<b>MW Recovery &amp; Component Uprates:</b>				
Quad Cities	95	110	59	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
<b>MUR:</b>				
LaSalle	32	40		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
<b>EPU:</b>				
Clinton	2	3	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
<b>Total</b>	<b>1,323</b>	<b>1,516</b>	<b>73</b>	

# 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 80 MW scheduled to be completed in 2009 and 2010; total expenditures expected to be \$4,400 million from 2008 – 2017 <sup>(1)</sup>**

(1) Dollars shown are nominal, reflecting 6% escalation, in millions.

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

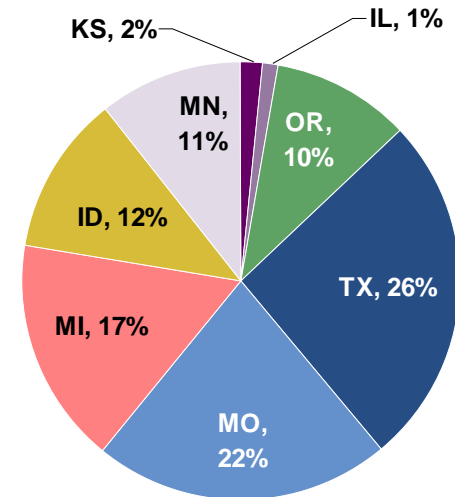
# John Deere Renewables Wind Acquisition



## Transaction Summary

- 735 operating MW of clean, renewable energy, along with 230 MW in advanced stages of development in Michigan
- 75% of the operating portfolio is contracted
- Purchase price of \$860 million plus an option for \$40 million upon commencement of construction of the development projects
- Attractive economics – EPS and cash flow accretive

## Operating Assets – Geographical Distribution



**Acquisition positions Exelon as a large wind operator, complementing its world-class nuclear fleet**

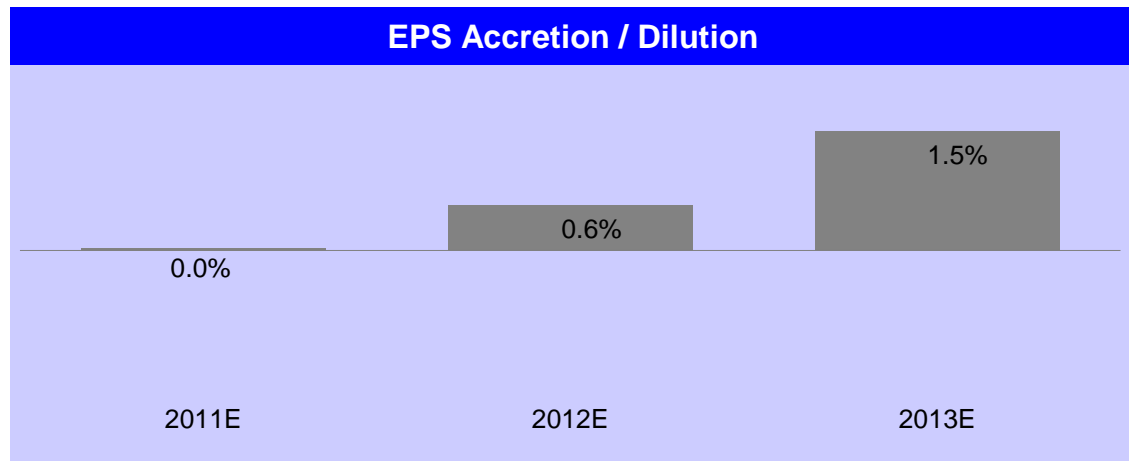
# John Deere Renewables Acquisition – Strategic Rationale



- Diversify with additional clean generation
  - JDR's proven wind platform provides unique opportunity and entry point into U.S. wind business
  - Provides diversity in geographic presence and generation type
  - Supports Exelon 2020 by adding more “clean” generation to our portfolio and positions us for potential federal renewable portfolio standard (RPS)
- Contracted portfolio with option for future growth
  - 75% of operating portfolio sold under long-term PPAs
  - 1,468 additional MW in pipeline, of which 230 MW have executed PPAs
  - Only plan further development of contracted assets
- Attractive economics and good fit
  - Purchase price compares favorably with other wind transactions
  - Disciplined investment approach aligned with Exelon's approach
  - Addition of strong renewable energy development team

**Acquisition further enhances Exelon's strong environmental leadership and provides future opportunities for incremental development**

# John Deere Renewables Acquisition – Financials Are Attractive



- EPS breakeven in 2011, accretive beginning in 2012
  - Assumes transaction is funded with 100% debt
- EBITDA run-rate of ~\$150M/year including PTCs <sup>(1)</sup> (including Michigan development projects)
- Free cash flow accretive by 2013
  - Includes estimated capex (before tax incentives) of \$450-\$500M in 2011-2012 for Michigan development projects
- Expect transaction to have minimal impact on credit metrics

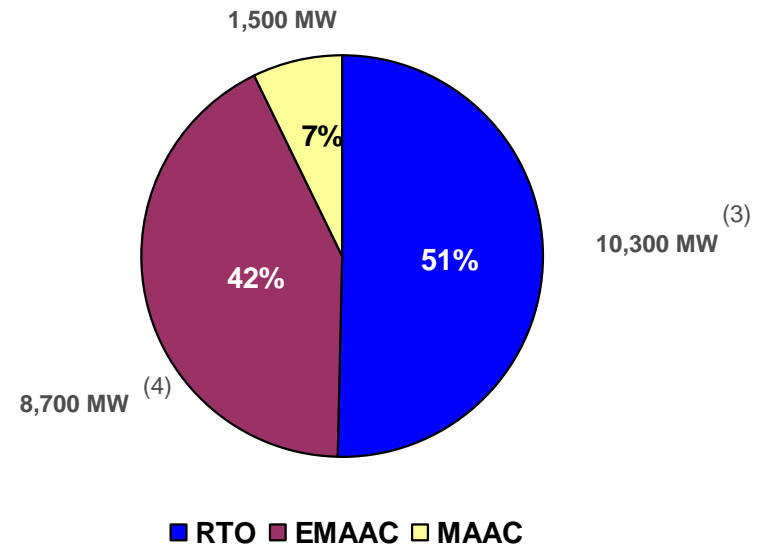
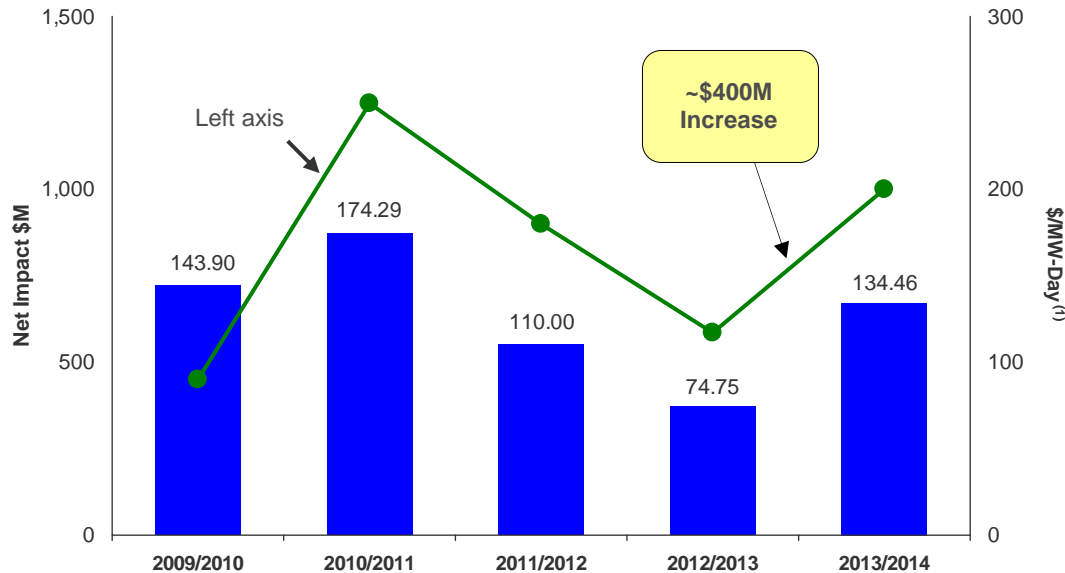
(1) Production Tax Credits

# PJM RPM Capacity Auction



## PJM RPM Capacity Prices and Auction (\$MW-day)

## Capacity by Region Eligible for 2014/15 RPM Base Residual Auction <sup>(2)</sup>



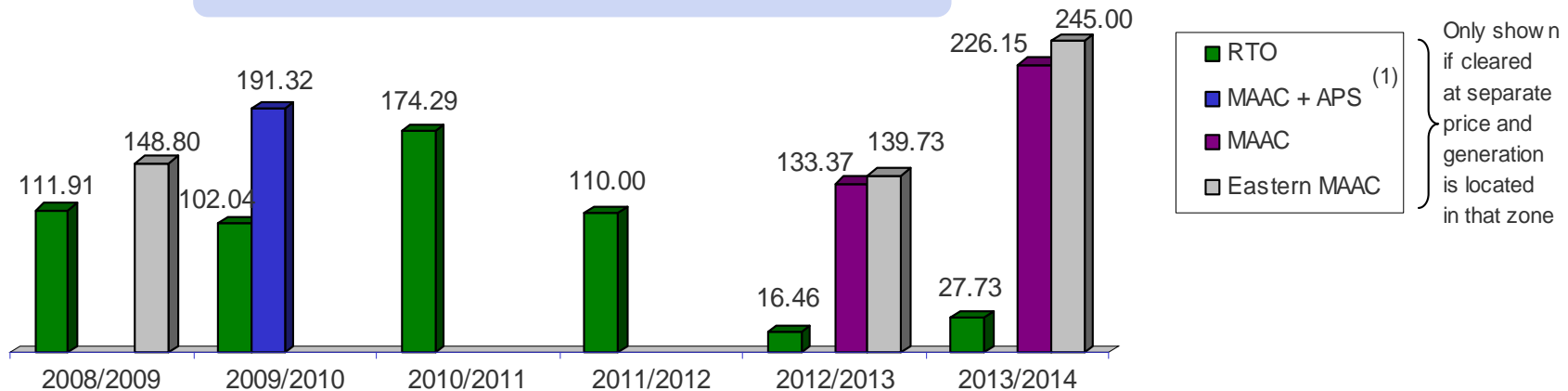
**2013/14 RPM capacity prices result in a \$400 million revenue increase to Exelon over the prior auction; expect 2014/15 auction to result in blended prices at least as high**

- (1) Weighted average \$/MW-Day would apply if all generation cleared in the highlighted zone.
- (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.
- (3) Elwood contract expires on 12/31/12 and Kincaid contract expires on 2/28/13.
- (4) Reflects decision in December 2010 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.

# PJM RPM Auction Results



## PJM RPM Auction (\$/MW-day)



## Exelon Generation Eligible Capacity within PJM Reliability Pricing Model (2)

	2009/2010		2010/2011		2011/2012	2012/2013	2013/2014
<i>in MW</i>	Capacity (3)	Obligation	Capacity (3)	Obligation	Capacity (3)	Capacity (3)	Capacity (3)
RTO	12,800	3,800 - 4,100 (5)	23,900	9,300 - 9,400 (4)	23,200	12,100 (6)	10,300 (6)
EMAAC						9,500	8,700 (7)
MAAC + APS	11,100	9,300 - 9,400 (5)					
MAAC						1,500	1,500
<b>Avg (\$/MW-Day) (8)</b>	<b>\$143.90</b>		<b>\$174.29</b>		<b>\$110.00</b>	<b>\$74.75</b>	<b>\$134.46</b>

(1) MAAC = Mid-Atlantic Area Council; APS = Allegheny Power System.

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

(3) All capacity values are in installed capacity terms (summer ratings) located in the areas.

(4) Obligation represents the remainder of the ComEd auction load that ends in May 2010.

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

(6) Elwood contract expires on 12/31/12 and Kincaid contract expires on 2/28/13.

(7) Reflects decision in December 2010 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.

(8) Weighted average \$/MW-Day would apply if all generation cleared in the highlighted zones. 23

# **Exelon Generation Hedging Disclosures**

(As disclosed on July 22, 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 June 30, 2010. We update this information on a quarterly basis and will next update it in the third quarter earnings call materials in late October.

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

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# Portfolio Management Objective

## Align Hedging Activities with Financial Commitments



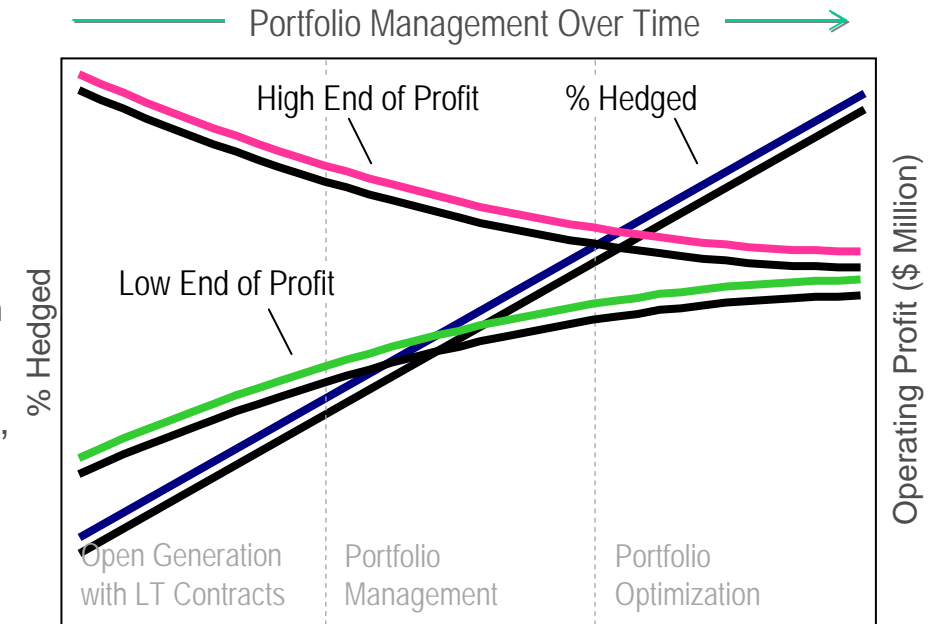
➤ **Exelon's hedging program is designed to protect the long-term value of our generating fleet and maintain an investment-grade balance sheet**

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

➤ **Consider market, credit, operational risk**

➤ **Approach to managing volatility**

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



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

- Wholesale and retail sales
- 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



	2010	2011	2012
<b>Estimated Open Gross Margin (\$ millions) <sup>(1)(2)</sup></b>	<b>\$5,700</b>	<b>\$5,300</b>	<b>\$5,100</b>

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

## Reference Prices <sup>(1)</sup>

Henry Hub Natural Gas (\$/MMBtu)	\$4.77	\$5.34	\$5.68
NI-Hub ATC Energy Price (\$/MWh)	\$33.17	\$32.63	\$34.22
PJM-W ATC Energy Price (\$/MWh)	\$44.76	\$45.54	\$46.86
ERCOT North ATC Spark Spread (\$/MWh) <sup>(3)</sup>	\$1.28	\$(0.02)	\$0.53

(1) Based on June 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



	2010	2011	2012
<b>Expected Generation (GWh) <sup>(1)</sup></b>	<b>167,500</b>	<b>163,000</b>	<b>162,600</b>
Midwest	100,000	98,700	97,500
Mid-Atlantic	58,900	57,000	57,000
South	8,600	7,300	8,100
<b>Percentage of Expected Generation Hedged <sup>(2)</sup></b>	<b>96-99%</b>	<b>86-89%</b>	<b>57-60%</b>
Midwest	96-99	86-89	54-57
Mid-Atlantic	96-99	90-93	59-62
South	97-100	66-69	51-54
<b>Effective Realized Energy Price (\$/MWh) <sup>(3)</sup></b>			
Midwest	\$46.00	\$43.50	\$44.50
Mid-Atlantic	\$36.50	\$57.50	\$51.00
ERCOT North ATC Spark Spread	\$0.00	\$(2.00)	\$(5.50)

(1) Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted for capacity. Expected generation is based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 10 refueling outages in 2010 and 11 refueling outages in 2011 and 2012 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 94.1%, 93.2% and 92.9% in 2010, 2011 and 2012 at Exelon-operated nuclear plants. These estimates of expected generation in 2011 and 2012 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.

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# Exelon Generation Gross Margin Sensitivities

(with Existing Hedges)

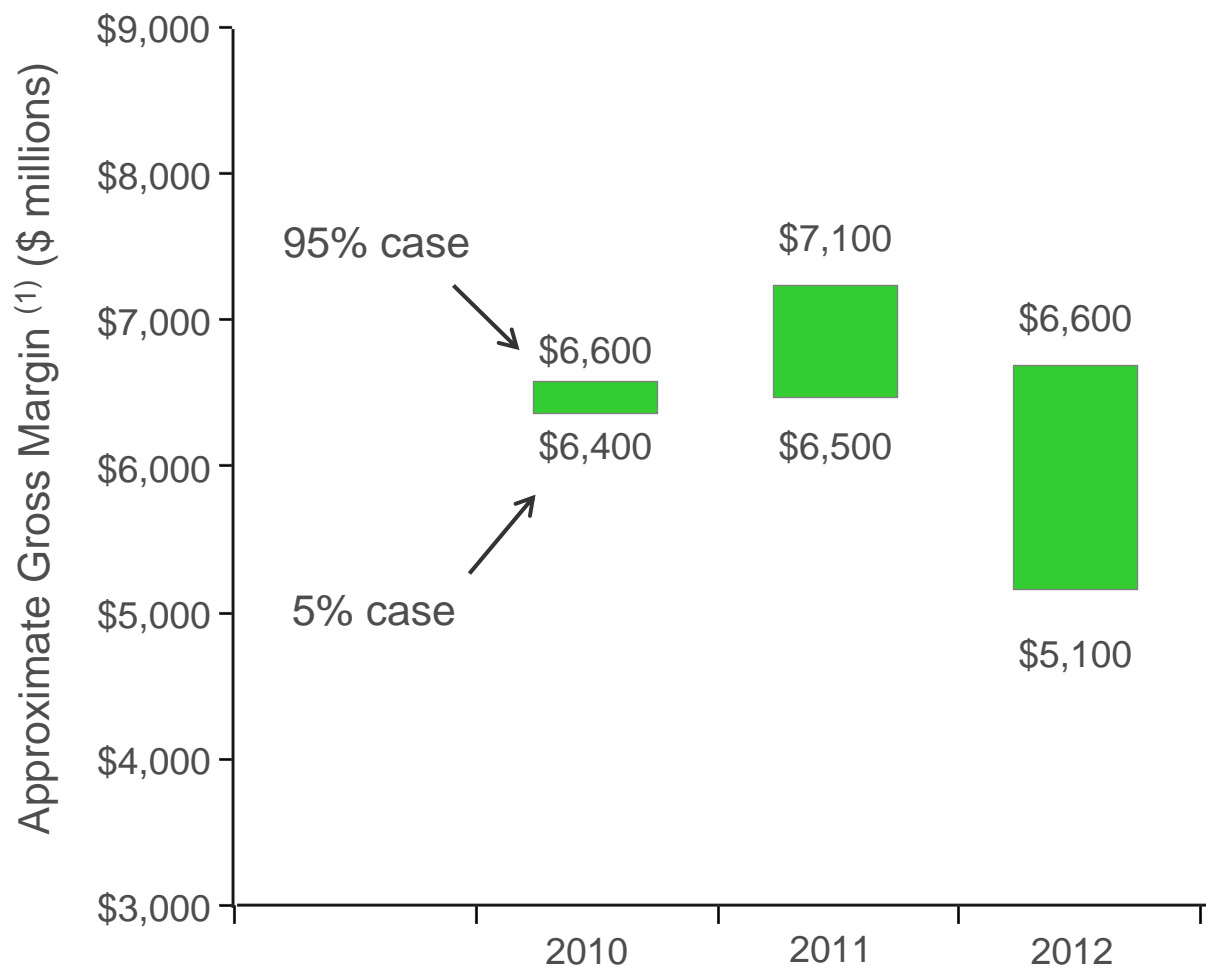


	2010	2011	2012
<b>Gross Margin Sensitivities with Existing Hedges (\$ millions)<sup>(1)</sup></b>			
Henry Hub Natural Gas			
+ \$1/MMBtu	\$20	\$100	\$260
- \$1/MMBtu	\$(15)	\$(90)	\$(245)
<hr/>			
NI-Hub ATC Energy Price			
+\$5/MWH	\$10	\$75	\$220
-\$5/MWH	\$(5)	\$(65)	\$(210)
<hr/>			
PJM-W ATC Energy Price			
+\$5/MWH	\$5	\$30	\$130
-\$5/MWH	\$ -	\$(25)	\$(125)
<hr/>			
Nuclear Capacity Factor			
+1% / -1%	+/- \$25	+/- \$45	+/- \$45

(1) Based on June 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.

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



(1) Represents an approximate range of expected gross margin, taking into account hedges in place, between the 5th and 95th percent confidence levels assuming all unhedged supply is sold into the spot market. Approximate gross margin ranges are based upon an internal simulation model and are subject to change based upon market inputs, future transactions and potential modeling changes. These ranges of approximate gross margin in 2011 and 2012 do not represent earnings guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years. The price distributions that generate this range are calibrated to market quotes for power, fuel, load following products, and options as of June 30, 2010.

# Illustrative Example

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## of Modeling Exelon Generation 2010 Gross Margin (with Existing Hedges)



	Midwest	Mid-Atlantic	ERCOT
Step 1 Start with fleetwide open gross margin	<div> <div></div> <div>\$5.70 billion</div> <div></div> </div>		
Step 2 Determine the mark-to-market value of energy hedges	100,000GWh * 97% * (\$46.00/MWh-\$33.17/MWh) = \$1.24 billion	58,900GWh * 97% * (\$36.50/MWh-\$44.76/MWh) = \$(0.47 billion)	8,600GWh * 98% * (\$0.00/MWh-\$1.28/MWh) = \$(0.01) billion
Step 3 Estimate hedged gross margin by adding open gross margin to mark-to-market value of energy hedges	Open gross margin: MTM value of energy hedges: Estimated hedged gross margin:	\$5.70 billion <u>\$1.24 billion + \$(0.47 billion) + \$(0.01) billion</u> <b>\$6.46 billion</b>	



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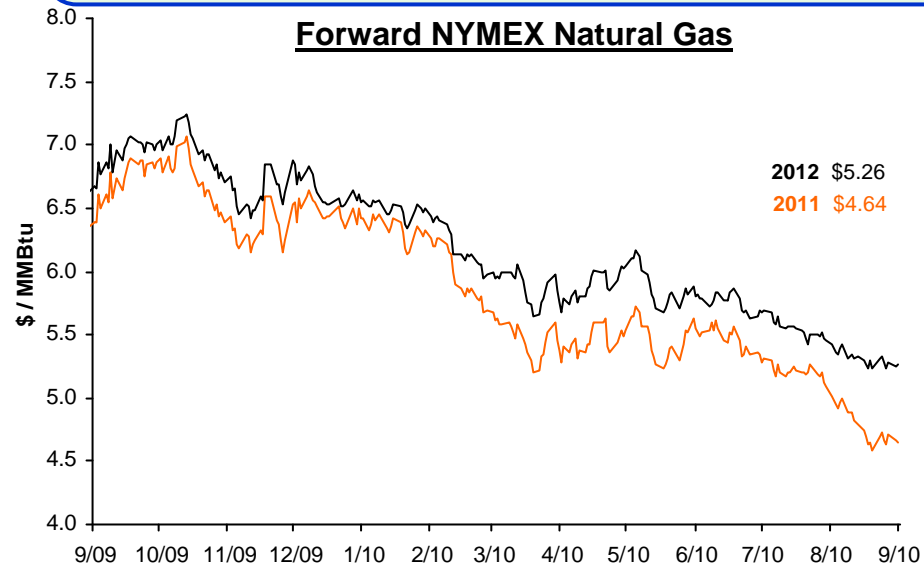
# Market Price Snapshot

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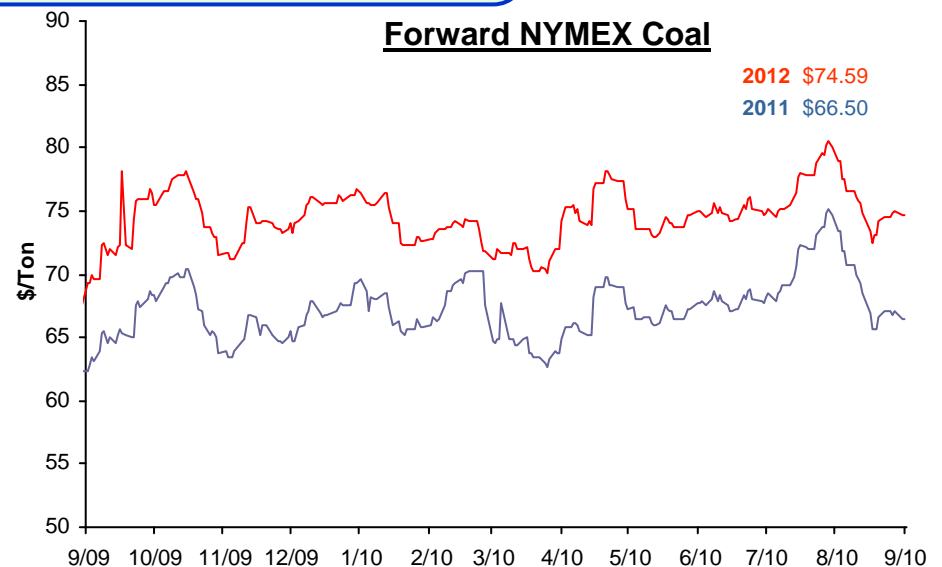


Rolling 12 months, as of September 8<sup>th</sup>, 2010. Source: OTC quotes and electronic trading system. Quotes are daily.

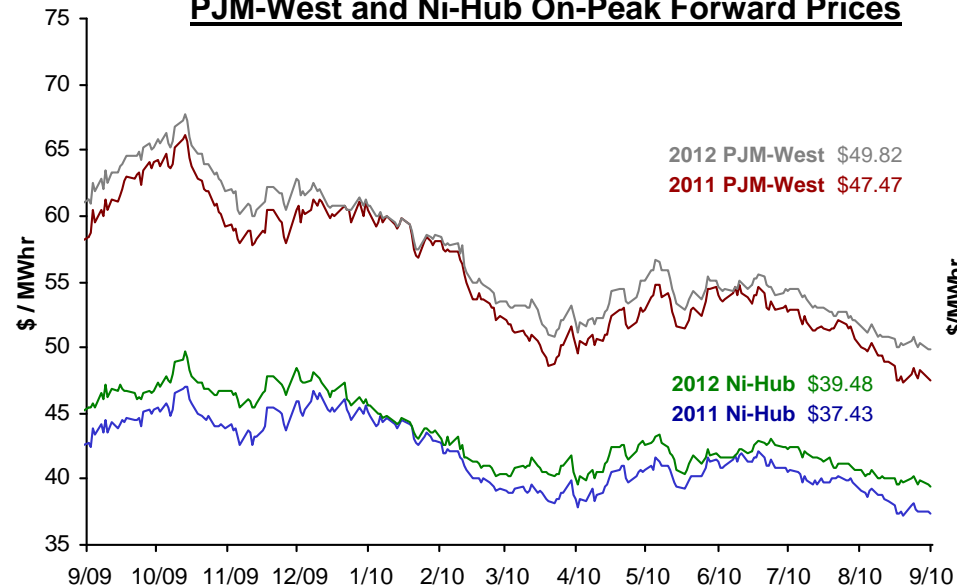
### Forward NYMEX Natural Gas



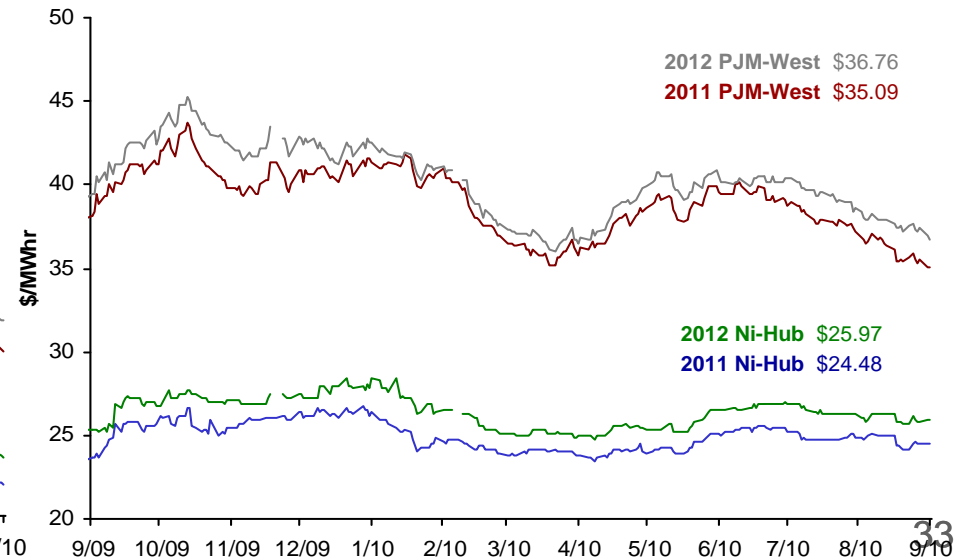
### Forward NYMEX Coal



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



### PJM-West and Ni-Hub Wrap Forward Prices



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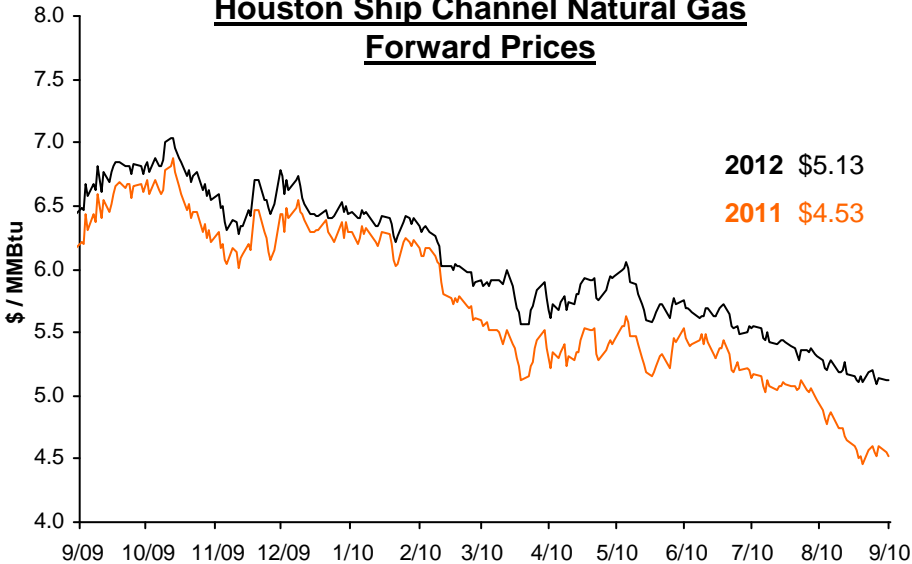
# Market Price Snapshot

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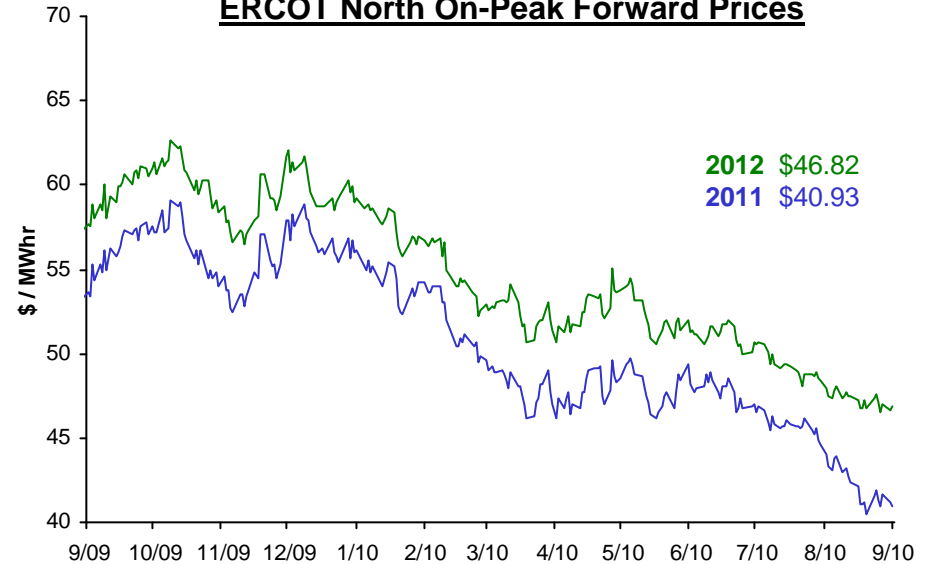
Rolling 12 months, as of September 8<sup>th</sup>, 2010. Source: OTC quotes and electronic trading system. Quotes are daily.



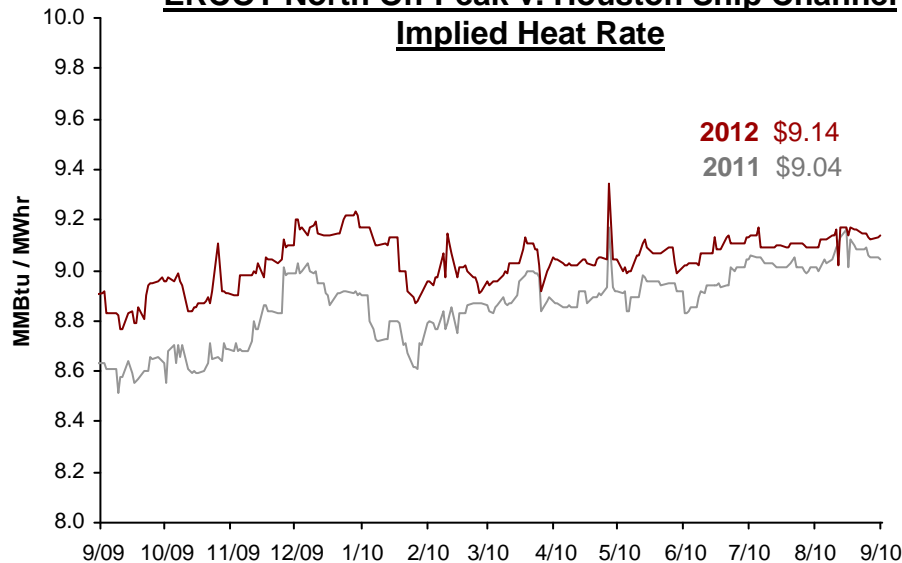
**Houston Ship Channel Natural Gas Forward Prices**



**ERCOT North On-Peak Forward Prices**

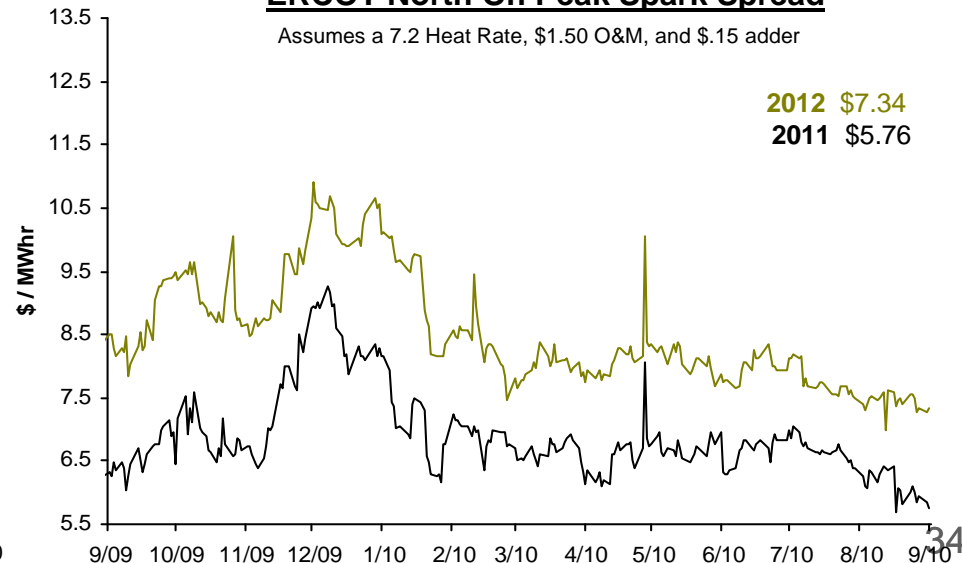


**ERCOT North On-Peak v. Houston Ship Channel Implied Heat Rate**



**ERCOT North On Peak Spark Spread**

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



**ComEd**®

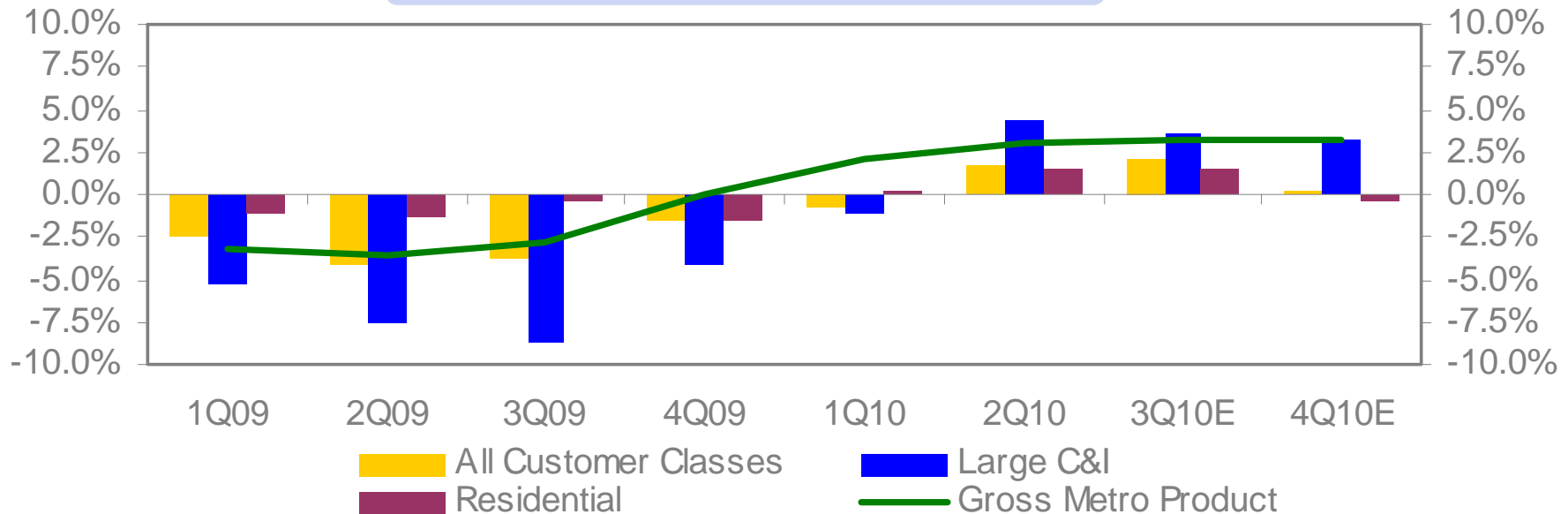
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# ComEd Load Trends



## Weather-Normalized Load Year-over-Year <sup>(4)</sup>



### Key Economic Indicators

	Chicago
Unemployment rate <sup>(1)</sup>	10.2%
2010 annualized growth in gross domestic/metro product <sup>(2)</sup>	2.9%
4/10 Home price index <sup>(3)</sup>	(1.5)%

- (1) Source: Illinois Dept. of Employment Security (June 2010)  
 (2) Source: Global Insight (June 2010)  
 (3) Source: S&P Case-Shiller Index  
 (4) Not adjusted for leap year effect

### Weather-Normalized Load

	2009 <sup>(4)</sup>	2Q10	2010E
Average Customer Growth	(0.4)%	0.2%	0.2%
Average Use-Per-Customer	<u>(1.0)%</u>	<u>1.4%</u>	<u>0.5%</u>
Total Residential	(1.4)%	1.6%	0.7%
Small C&I	(2.2)%	(0.1)%	(0.6)%
Large C&I	(6.7)%	4.3%	2.5%
All Customer Classes	(3.3)%	1.8%	0.8%

Note: The information on this slide is the same as disclosed on 7/22/10 and has not been updated to reflect any changes that may have occurred since that date.  
 C&I = Commercial & Industrial

# ComEd Delivery Service Rate Case Filing Summary

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(\$ in millions)	Requested Revenue Increase
Rate Base: \$7,717 million <sup>(1)</sup>	\$179 <sup>(2)</sup>
Capital Structure <sup>(3)</sup> : ROE – 11.50% / Common Equity – 47.33% / ROR – 8.99%	\$95
Pension and Post-retirement health care expenses <sup>(4)</sup>	\$55
Bad debt costs (resets base level of bad debt to 2009 test year)	\$22
Other adjustments <sup>(5)</sup>	\$45
<b>Total (\$2,337 million revenue requirement) <sup>(6)</sup></b>	<b>\$396</b>

**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. ICC Docket #: 10-0467, <http://www.icc.illinois.gov/docket/casedetails.aspx?no=10-0467>.
- (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.

Note: ROE = Return on Equity, ROR = Return on Rate Base, ICC = Illinois Commerce Commission.

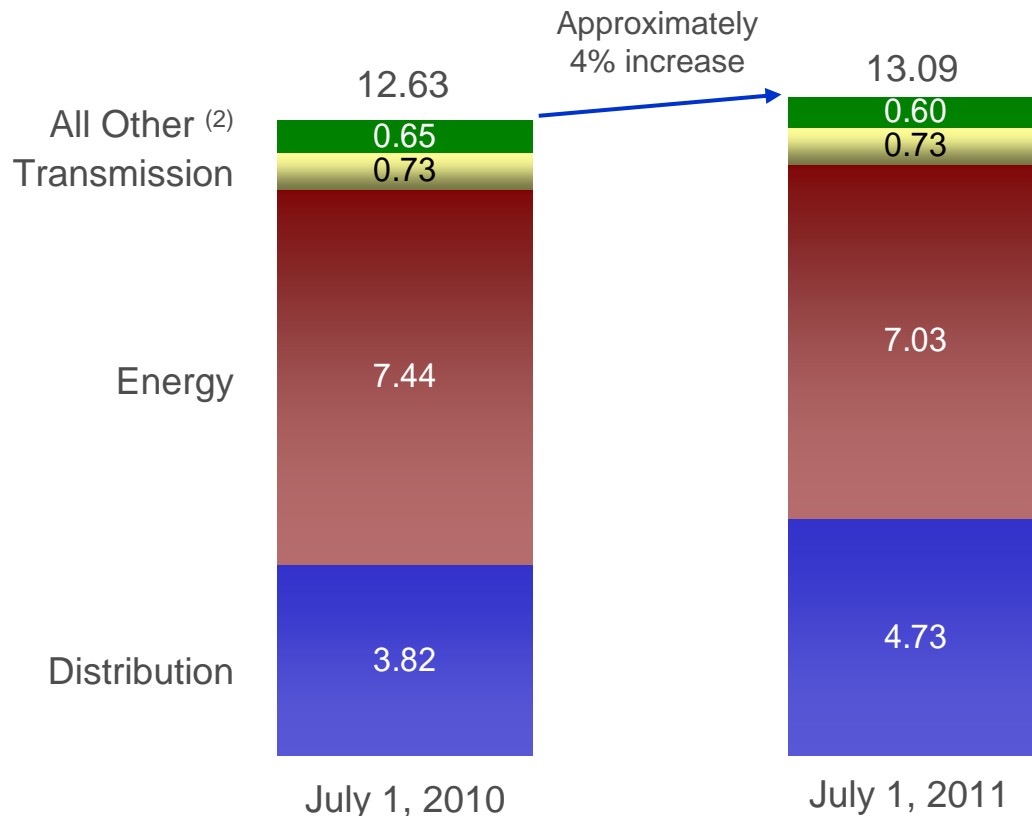
# ComEd Delivery Rate Case Residential Rate Impacts 2010 to 2011 <sup>(1)</sup>

ZEC-1-FIN-21

PUBLIC



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

**Proposed residential rate impact of 7% will be mitigated by impact of lower capacity prices resulting in a net 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 Service Rate Case Schedule



- Delivery Service Rate Case Filed – June 30, 2010
- Alt Reg Proposal Filed – August 31, 2010
- Intervenor and Rebuttal Testimony – 4Q 2010
- Hearings – January 2011
- Administrative Law Judge Order – March 31, 2011
- Final Order Expected – May 2011
- New Rates Effective – June 2011

# ComEd Delivery Rate Case Alternative Regulation (Alt Reg) Proposal

ZEC-JFIN-21

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- ComEd submitted an Alt Reg filing on August 31, 2010 proposing to recover the costs of pre-approved projects outside of the traditional rate case process
  - 9-month statutory process
- \$60 million proposal 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 <sup>(1)</sup>	\$10	-

- Customer benefits include:
  - Assured savings to customers – \$2 million on capped O&M costs for program costs (excluding CARE)
  - An incentive/penalty mechanism for performance above or under budget

**Proposal would allow for accelerated modernization of the distribution system, increased assistance to low-income households and the purchase of electric vehicles**

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





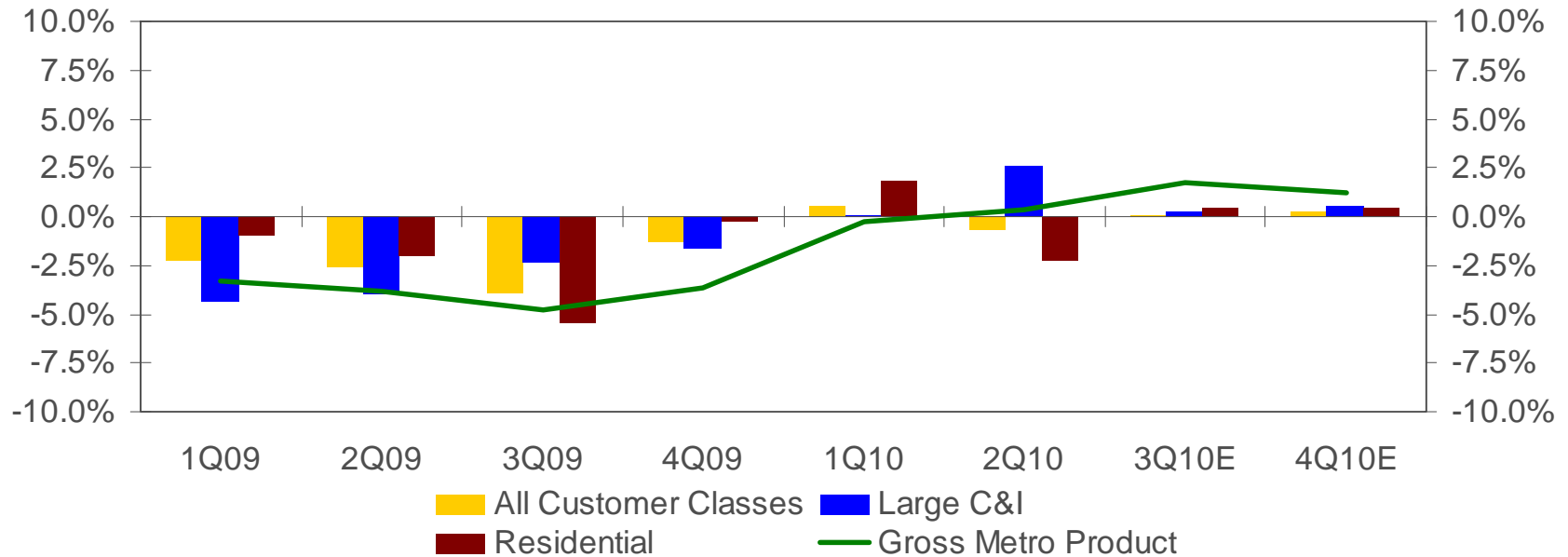
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# PECO Load Trends



## Weather-Normalized Load Year-over-Year <sup>(3)</sup>



### Key Economic Indicators

#### Philadelphia

Unemployment rate <sup>(1)</sup>	9.2%
2010 annualized growth in gross domestic/metro product <sup>(2)</sup>	0.8%

(1) Source: U.S Dept. of Labor Preliminary data (June 2010)

(2) Source: PECO estimate

(3) Not adjusted for leap year effect

### Weather-Normalized Load

	2009 <sup>(3)</sup>	2Q10	2010E
Average Customer Growth	(0.2)%	0.2%	0.0%
Average Use-Per-Customer	<u>(2.1)%</u>	<u>(2.5)%</u>	<u>0.3%</u>
Total Residential	(2.3)%	(2.3)%	0.2%
Small C&I	(2.7)%	(5.1)%	(1.8)%
Large C&I	(3.0)%	2.6%	0.9%
All Customer Classes	(2.6)%	(0.7)%	0.1%

Note: The information on this slide is the same as disclosed on 7/22/10 and has not been updated to reflect any changes that may have occurred since that date. 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 <sup>(1)</sup>	\$225 million	\$20 million
2011 Distribution Price Increase as % of Overall Customer Bill for Residential customers	<10% <sup>(2)</sup>	~8%

**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.

(2) Excluding Alternative Energy Portfolio Standards and default service surcharge. Assumes results from final procurement in September 2010 are the same as May 2010 procurement.

# PECO Procurement



## PECO Procurement Plan <sup>(1)</sup>

Customer Class	Products
<b>Residential</b>	<ul style="list-style-type: none"> <li>✓75% full requirements</li> <li>✓20% block energy</li> <li>✓5% energy only spot</li> </ul>
<b>Small Commercial</b> (peak demand <100 kW)	<ul style="list-style-type: none"> <li>✓90% full requirements</li> <li>✓10% full requirements spot</li> </ul>
<b>Medium Commercial</b> (peak demand >100 kW but ≤ 500 kW)	<ul style="list-style-type: none"> <li>✓85% full requirements</li> <li>✓15% full requirements spot</li> </ul>
<b>Large Commercial &amp; Industrial</b> (peak demand >500 kW)	<ul style="list-style-type: none"> <li>✓Fixed-priced full requirements <sup>(3)</sup></li> <li>✓Hourly full requirements</li> </ul>

## 2011 Supply Procured <sup>(2)</sup>

### Residential

- ✓ June '09 RFP average price of \$88.61/MWh
- ✓ Sept '09 RFP average price of \$79.96/MWh
- ✓ May '10 RFP average price of \$69.38/MWh
- ✓ Remaining 28% of full requirements procured in Sep '10

### Small Commercial

- ✓ Sept '09 / May '10 RFP aggregate result \$77.65/MWh
- ✓ Remaining 40% of full requirements procured in Sep '10

### Medium Commercial

- ✓ Sept '09 / May '10 RFP aggregate result \$77.89/MWh
- ✓ Remaining 42% of full requirements procured in Sep '10

### Large Commercial and Industrial

- ✓ Average price of \$77.55/MWh
- ✓ 100% of fixed-price full requirements procured in May '10 <sup>(3)</sup>

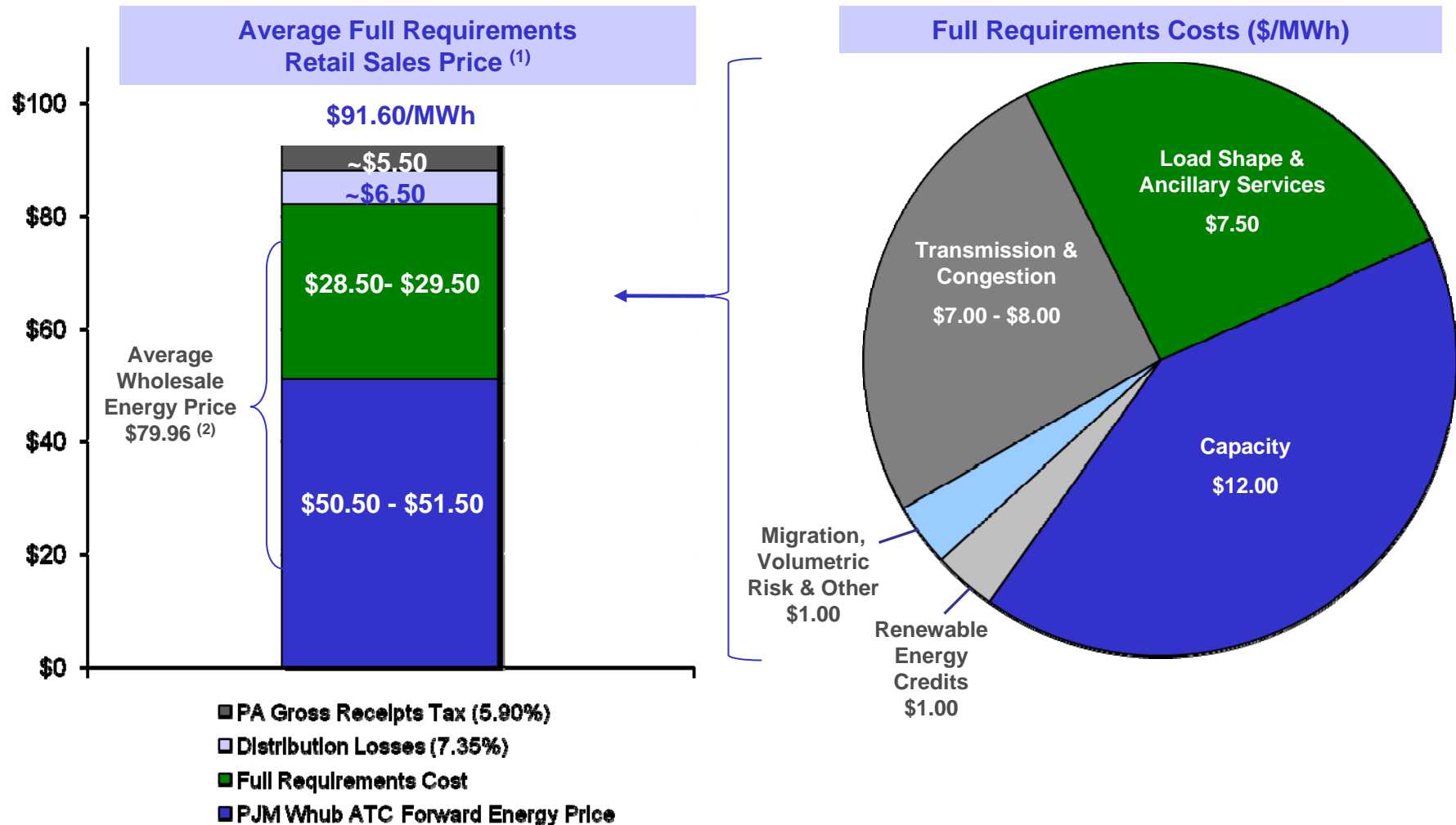
**Final RFP for 2011 supply was held on September 20, 2010; results will be public on October 14, 2010**

(1) See PECO Procurement website (<http://www.pecoprocmement.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. September 2010 results will be public in October.

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

# Estimated Build-Up of PECO Average Residential Full Requirements Price



(1) As provided by Exelon Generation.

(2) On Oct 21, 2009, the Independent Evaluator (NERA) announced a wholesale winning bid average price of \$79.96/MWh for PECO's Fall 2009 RFP (reflecting 17 & 29-month residential full requirements' products with delivery beginning Jan 1, 2011).

# Appendix

# 2009 GAAP EPS Reconciliation



<b>2009 GAAP EPS Reconciliation <sup>(1)</sup></b>	<b><u>ExGen</u></b>	<b><u>ComEd</u></b>	<b><u>PECO</u></b>	<b><u>Other</u></b>	<b><u>Exelon</u></b>
<b>2009 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share</b>	<b>\$3.16</b>	<b>\$0.54</b>	<b>\$0.54</b>	<b>\$(0.12)</b>	<b>\$4.12</b>
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)
<b>FY 2009 GAAP Earnings (Loss) Per Share</b>	<b>\$3.21</b>	<b>\$0.56</b>	<b>\$0.53</b>	<b>\$(0.21)</b>	<b>\$4.09</b>

(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
  - Changes in decommissioning obligation estimates
  - 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
  - Other unusual items
  - Significant future changes to GAAP
- **Operating earnings guidance assumes normal weather for remainder of the year**



# Exelon Investor Relations Contacts



## Exelon Investor Relations

10 South Dearborn Street  
Chicago, Illinois 60603  
312-394-2345  
312-394-4082 (Fax)

**For copies of other presentations,  
annual/quarterly reports, or to be added  
to our email distribution list please  
contact:**

Martha Chavez, Executive Admin  
Coordinator  
312-394-4069  
Martha.Chavez@ExelonCorp.com

## Investor Relations Contacts:

**Stacie Frank, Vice President**  
312-394-3094  
Stacie.Frank@ExelonCorp.com

**Melissa Sherrod, Director**  
312-394-8351  
Melissa.Sherrod@ExelonCorp.com

**Paul Mountain, Manager**  
312-394-2407  
Paul.Mountain@ExelonCorp.com

**Marybeth Flater, Manager**  
312-394-8354  
Marybeth.Flater@ExelonCorp.com

**Sandeep Menon, Principal Analyst**  
312-394-7279  
Sandeep.Menon@ExelonCorp.com