UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

August 5, 2005
Date of Report (Date of earliest event reported)

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street – 37th Floor P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	23-2990190
1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 10 South Dearborn Street – 37th Floor P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-4321	36-0938600
1-1401	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348 (610) 765-6900	23-3064219

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Section 7 – Regulation FD
Item 7.01. Regulation FD Disclosure

On August 5, 2005, Exelon Corporation (Exelon) will hold an investor conference in New York City. Attached as Exhibit 99.1 to this Current Report on Form 8-K are the slides and handouts to be used at the conference.

In connection with the conference, on August 5, 2005, Exelon issued a press release announcing that it raised its 2005 adjusted (non-GAAP) operating earnings guidance and announcing its 2006 adjusted (non-GAAP) operating earnings guidance. The press release is attached as Exhibit 99.2 to this Current Report on Form 8-K.

Section 9 — Financial Statements and Exhibits
Item 9.01 — Financial Statements and Exhibits

(c) Exhibits

Exhibit No.	Description
99.1	Slides and handouts for investor conference
99.2	Press release announcing earnings guidance

* * * * *

This combined Form 8-K is being furnished separately by Exelon, Commonwealth Edison Company (ComEd), PECO Energy Company (PECO) and Exelon Generation Company, LLC (Generation) (Registrants). Information contained herein relating to any individual registrant has been furnished by such registrant on its own behalf. No registrant makes any representation as to information relating to any other registrant.

Except for the historical information contained herein, certain of the matters discussed in this Report are forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by a registrant include those factors discussed herein, as well as the items discussed in (a) the Registrants' 2004 Annual Report on Form 10-K—ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Business Outlook and the Challenges in Managing Our Business for each of Exelon, ComEd, PECO and Generation, (b) the Registrants' 2004 Annual Report on Form 10-K—ITEM 8. Financial Statements and Supplementary Data: Exelon—Note 20, ComEd—Note 15, PECO—Note 14 and Generation—Note 16, (c) Exelon's Current Report on Form 8-K filed on May 13, 2005, including those discussed in Exhibit 99.2 "Management's Discussion and Analysis of Financial Condition and Results of Operation " and Exhibit 99.3 "Financial Statements and Supplementary Data", (d) Generation's Current Report on Form 8-K filed on May 13, 2005, including those discussed in Exhibit 99.5 "Management's Discussion and Analysis of Financial Condition and Results of Operation" and Exhibit 99.6 "Financial Statements and Supplementary Data" and (e) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

EXELON CORPORATION
COMMONWEALTH EDISON COMPANY
PECO ENERGY COMPANY
EXELON GENERATION COMPANY, LLC

/s/ J. Barry Mitchell

J. Barry Mitchell
Senior Vice President, Chief Financial Officer
and Treasurer

August 5, 2005

Exhibit 99.1

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 Corporation's 2004 Annual Report on Form 10-K in (a) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations-Business Outlook and the Challenges in Managing the Business for each of Exelon, ComEd, PECO and Generation and (b) ITEM 8. Financial Statements and Supplementary Data: Exelon-Note 20, ComEd-Note 15, PECO-Note 14 and Generation-Note 16 and (2) Exelon's Current Report on Form 8-K filed on May 13, 2005 in (a) Exhibit 99.2 Management's Discussion and Analysis of Financial Condition and Results of Operations - Exelon - Business Outlook and the Challenges in Managing the Business and (b) Exhibit 99.3 Financial Statements and Supplementary Data - Exelon Corporation 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). A discussion of risks associated with the proposed merger of Exelon and Public Service Enterprise Group, Incorporated (PSEG) is included in the joint proxy statement/prospectus that Exelon filed with the SEC pursuant to Rule 424(b)(3) on June 3, 2005 (Registration No. 333-122704). 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.

Realizing the Promise, Pursuing the Vision

John Rowe
Chairman, President & Chief Executive Officer

Exelon Investor Conference
New York City
August 5, 2005

Today's Agenda

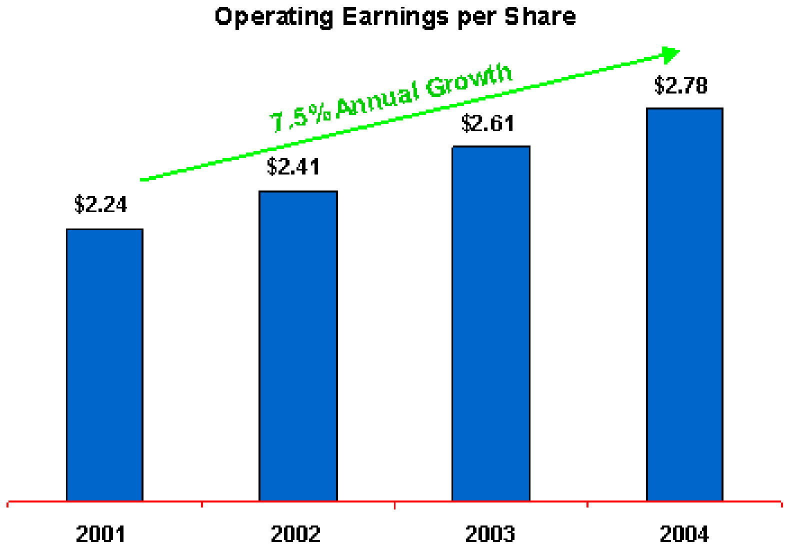
Exelon

Realizing the Promise, Pursuing the Vision

8:00 a.m.–8:45 a.m.	John Rowe – Strategic Overview
8:45 a.m.–9:15 a.m.	Jack Skolds – Operations Update
9:15 a.m.–9:45 a.m.	Ian McLean – Power Marketing Update
9:45 a.m.–10:00 a.m.	Break
10:00 a.m.–10:30 a.m.	Betsy Moler – Merger/Federal Regulatory Update
10:30 a.m.–11:00 a.m.	Anne Pramaggiore – IL Regulatory/Legislative Update
11:00 a.m.–11:30 a.m.	John Young – Financial Overview
11:30 a.m.–12:00 p.m.	John Rowe – Wrap-up and Q&A
12:30 p.m.–2:00 p.m.	Lunch and informal discussion

Realizing the Promise . . .

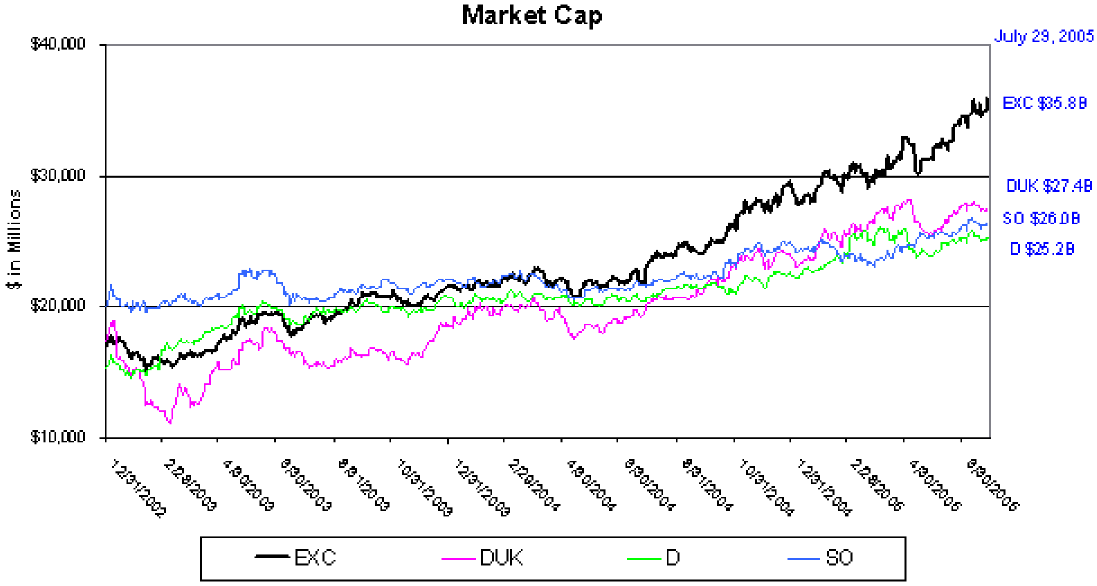
We have, in so many ways, begun to realize the promise of the PECO/ComEd Merger



Note: See presentation appendix for reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS

Realizing the Promise . . .

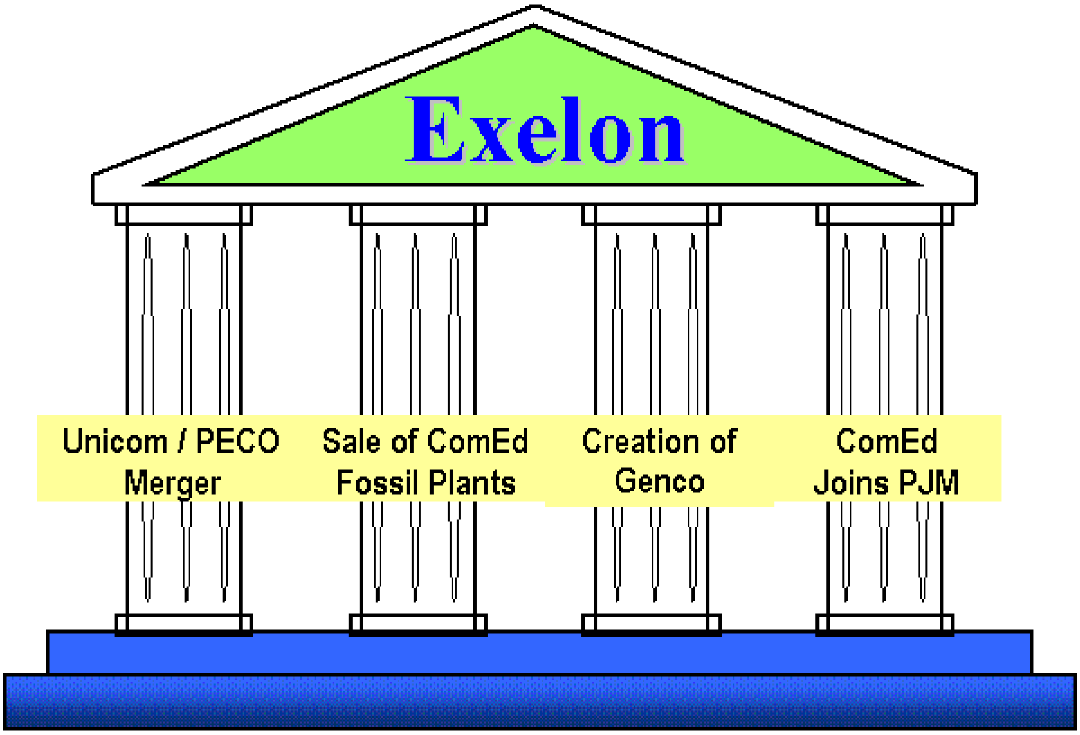
- 30% more valuable than next largest peer
  - 40% after merger with PSEG



Data source: Thomson Financial

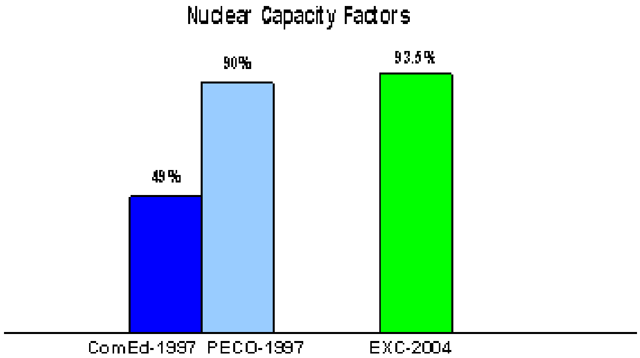
By Fostering Competition

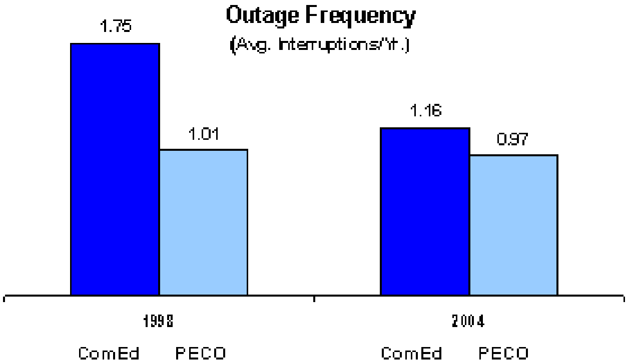
Exelon today is a product of industry restructuring

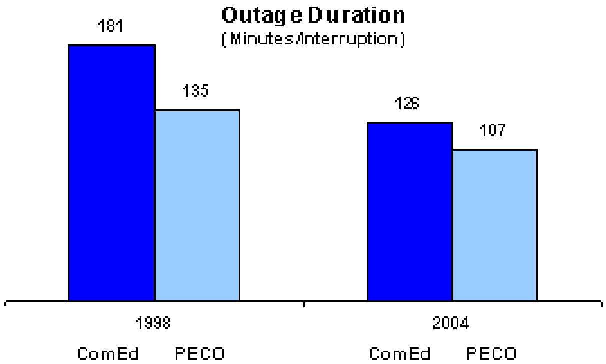


By Improved Operations

- Exceptional nuclear and generation performance
- Continued improvement in Energy Delivery





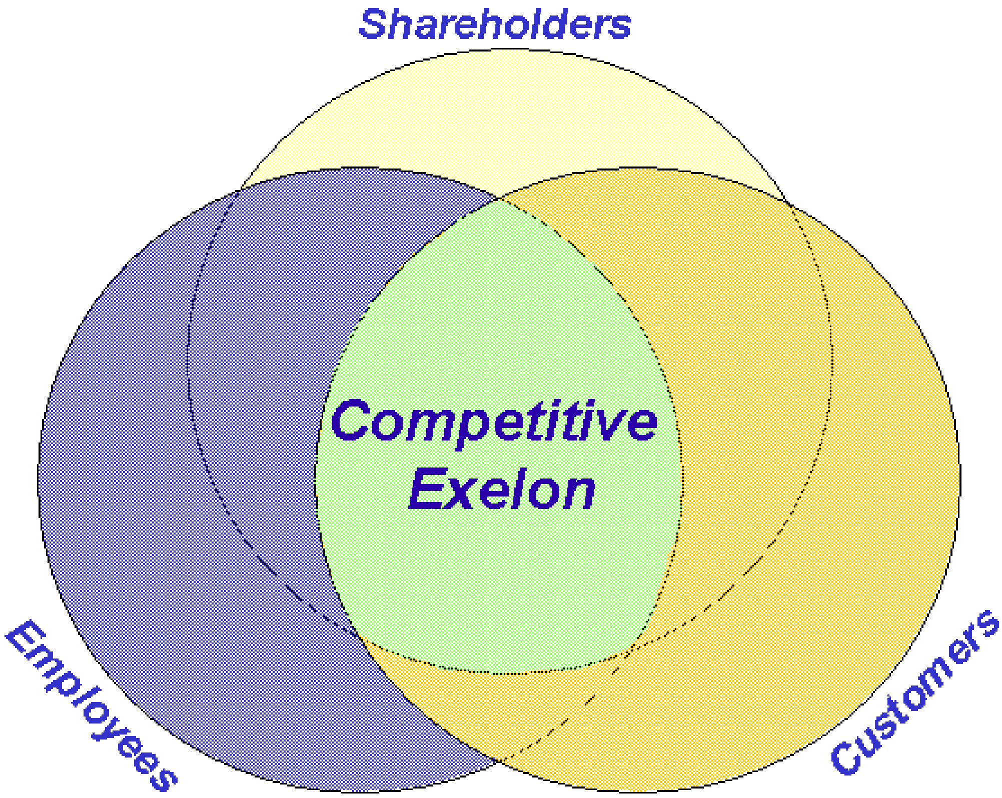


And by Continued Financial Discipline

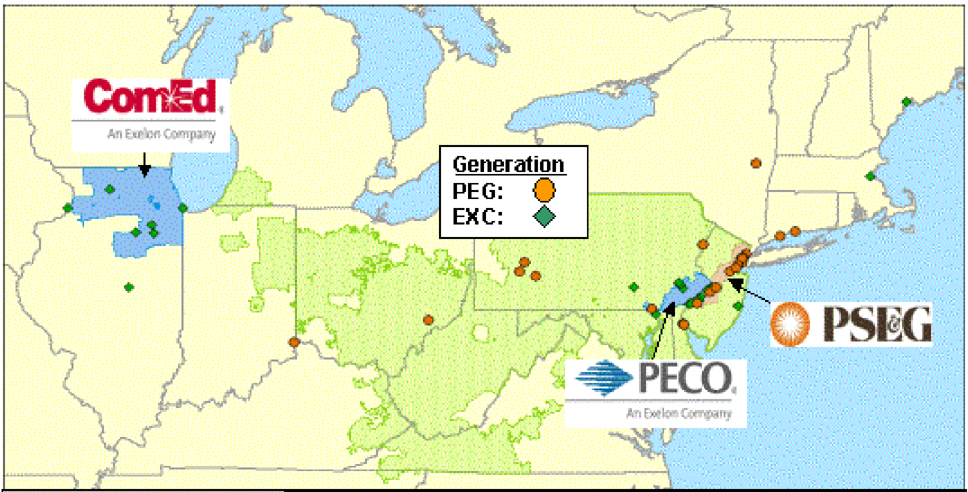
Exelon

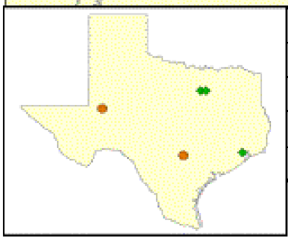
- Controlling costs
- Cutting our losses
- Strengthening our Balance Sheet
- Managing commodity risk

To the Benefit of All Stakeholders



We're Better Positioned Now than Ever





	Exelon	PSEG	EE&G	U.S. Rank
Nuclear MWs	16,751	3,484	20,235	1
Total MWs (1)	34,457	17,018	51,475	1
Elec. Customers	5,200,000	2,100,000	7,300,000	1
Gas Customers	460,000	1,700,000	2,160,000	7

(1) Year-end 2004; Generation numbers include long-term contracts.
Note: EE&G MWs do not include effect of any market power mitigation.

Appendix:

Reconciliation of GAAP Reported and Adjusted (non-GAAP)
Operating Earnings per Diluted Share

2001 GAAP Reported EPS	**$ 2.21**
Cumulative effect of adopting SFAS No. 133	(0.02)
Employee severance costs	0.05
Litigation reserves	0.01
Net loss on investments	0.01
CTC prepayment	(0.01)
Wholesale rate settlement	(0.01)
Settlement of transition bond swap	—
2001 Adjusted (non-GAAP) Operating EPS	**$ 2.24**
2002 GAAP Reported EPS	**$ 2.22**
Cumulative effect of adopting SFAS No. 141 and No. 142	0.35
Gain on sale of investment in AT&T Wireless	(0.18)
Employee severance costs	0.02
2002 Adjusted (non-GAAP) Operating EPS	**$ 2.41**
2003 GAAP Reported EPS	**$ 1.38**
Boston Generating impairment	0.87
Charges associated with investment in Sithe Energies, Inc.	0.27
Severance	0.24
Cumulative effect of adopting SFAS No. 143	(0.17)
Property tax accrual reductions	(0.07)
Enterprises' Services goodwill impairment	0.03
Enterprises' impairments due to anticipated sale	0.03
March 3 ComEd Settlement Agreement	0.03
2003 Adjusted (non-GAAP) Operating EPS	**$ 2.61**
2004 GAAP Reported EPS	**$ 2.78**
Charges associated with debt repurchases	0.12
Investments in synthetic fuel-producing facilities	(0.10)
Severance	0.07
Cumulative effect of adopting FIN No. 46-R	(0.05)
Settlement associated with the storage of spent nuclear fuel	(0.04)
Boston Generating 2004 impact	(0.03)
Charges associated with investment in Sithe Energies, Inc.	0.02
Costs related to proposed merger with PSEG	0.01
2004 Adjusted (non-GAAP) Operating EPS	**$ 2.78**

Note: EPS figures reflect 2-for-1 stock split effective 5/5/04. Three-year 2004/2001 compound annual growth rate (CAGR): $2.78/$2.21 = 7.9% based on GAAP reported results. Three-year 2004/2001 CAGR: $2.78/$2.24 = 7.5% based on adjusted (non-GAAP) operating results.

Operations Update

John L. Skolds, President, Exelon Energy Delivery and
President, Exelon Generation

Exelon Investor Conference
New York City
August 5, 2005

Exelon Operations

- The Management Model is being applied throughout Exelon operations
  - Improving material condition
  - Improving reliability
  - Improving cost management
  - Consistently replicating good results

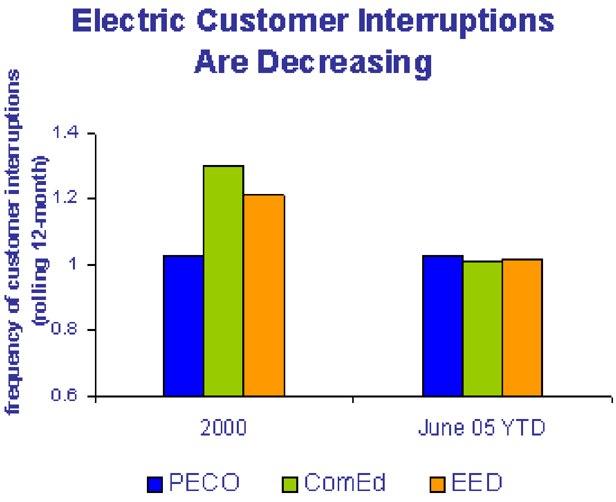
- The Model will continue to be applied under the Nuclear Operating Services Agreement and throughout operations post-merger to achieve:
  - Potential merger synergies
  - The benefits of size and scale
  - A high performance, results-oriented culture

The Management Model drives strong repeatable results

Energy Delivery – Reliability

System initiatives are leading to improved reliability

- Investing in transmission and distribution system reliability
- Improving material condition of bare steel gas system
- Fixing top-priority distribution circuits
- Completing high-impact corrective maintenance
- Early planning and completion of summer critical work



Energy Delivery – Keeping the lights on

Energy Delivery – High Performance

Exelon

Building a high-performance operations culture

- Leveraging the experience of the Nuclear Management Model
- Focusing on sound fundamentals
- Improving work management and scheduling processes to reduce cost and improve efficiency and response
- Preventing human performance errors
- Improving response during and after storms

Energy Delivery – Operational excellence is fundamental

Energy Delivery – Becoming Customer-Focused

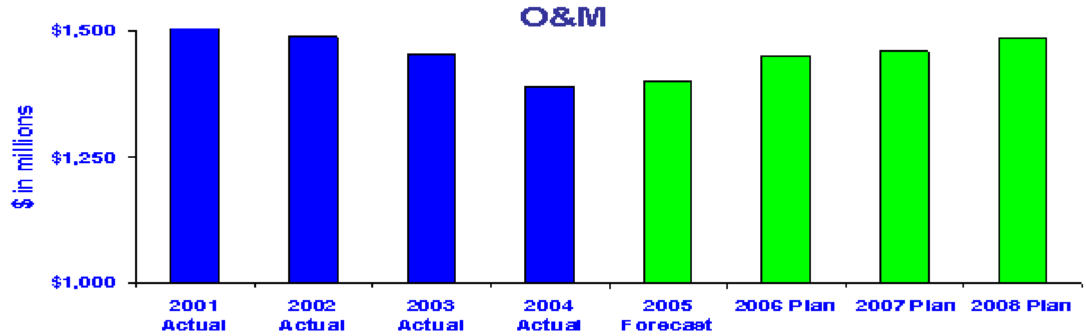
Targeting top quartile in customer satisfaction

- Performing reliably – fewer outages and faster restoration times
- Communicating better during storm and non-storm outages
- Making customer contact a better experience
- Creating a customer-focused culture
- "Telling our story" through media outreach
- Implementing a common customer system

Energy Delivery – 1st quartile customer satisfaction in 2007

Energy Delivery – Optimizing Spending

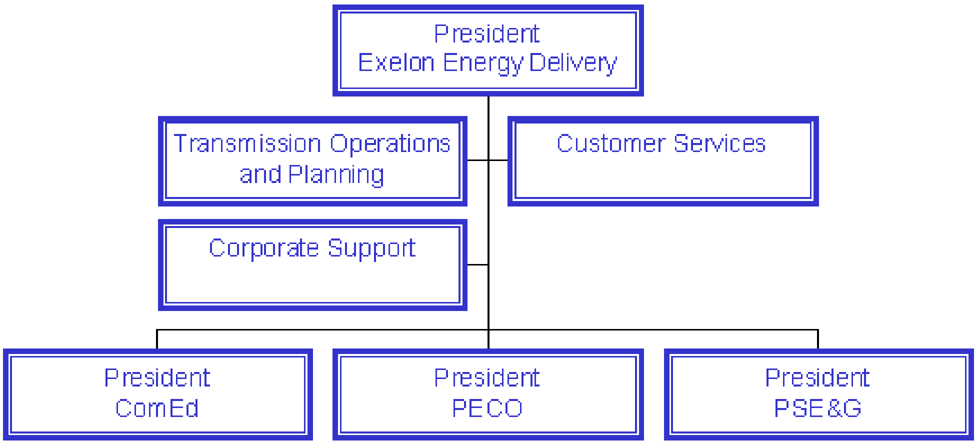
- Reliability improvements achieved while O&M expenses reduced more than 10% since 2001
  - Future expenses not expected to reach 2002 levels until 2008



- Capital strategically invested to support continued system growth and performance improvements
- Improved long-term planning and work management processes reducing spend variability and enhancing productivity
- Spending plans coordinated with State and FERC rate strategies to optimize returns

Energy Delivery – Effective cost management & investment

Energy Delivery – Merger Integration



What will Exelon Electric & Gas Energy Delivery look like?

- Central management to ensure alignment and best practices
- Local utility operations
- Merger will be transparent to the customer

Energy Delivery – Centrally managed with local execution

Exelon Power Performance – Reliability

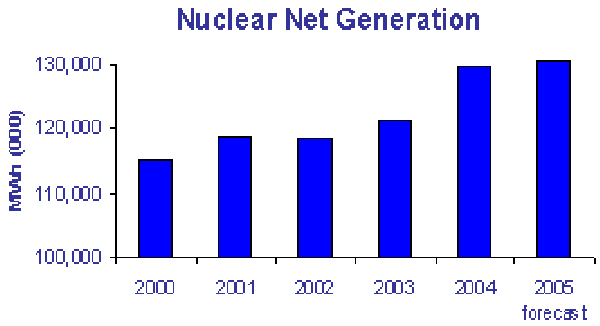
Targeted capital investment and sound operating fundamentals driving fleet efficiency and reliability

- Market-driven investments in plant improvements that increase unit profitability
- Material condition improvement resulting in improved unit reliability, heat rate and capacity
- Capitalizing on market opportunities through improved operating flexibility and market responsiveness

Application of Management Model has resulted in improved operations; will provide similar results in the larger PSEG fossil fleet

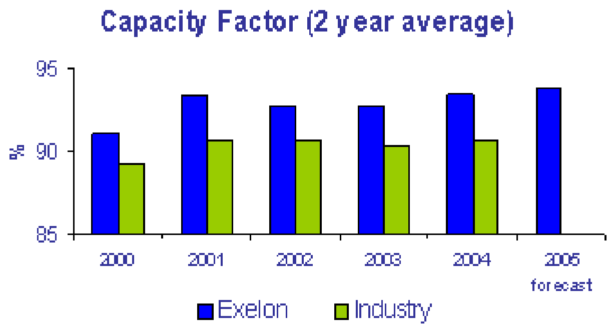
Exelon Power is well positioned to capitalize on market opportunities

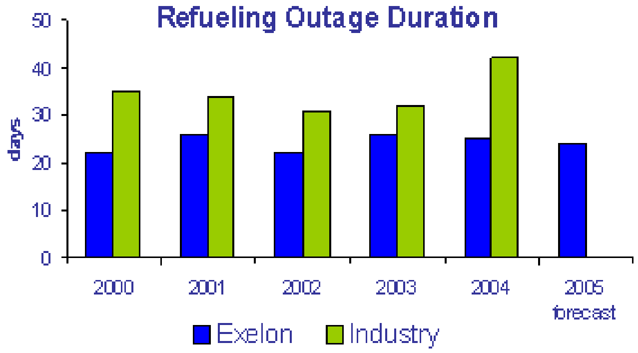
Nuclear Performance – Production



Sustained nuclear production reliability

- Continued growth in generation output
- Consistently high capacity factors
- Continued excellence in refueling outage performance





Exelon Nuclear's sustained reliability is a competitive advantage

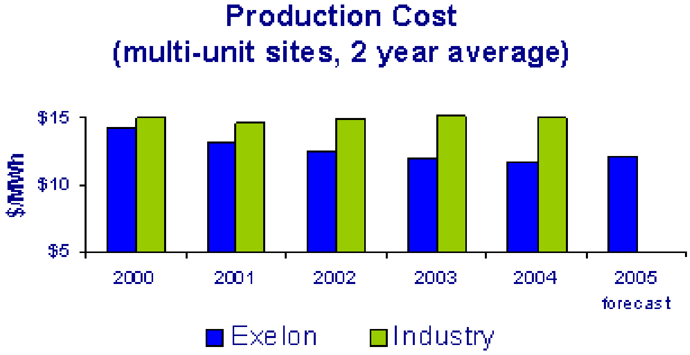
Data sources: Nucleonics Week, Electric Utility Cost Group. Exelon data excludes Salem

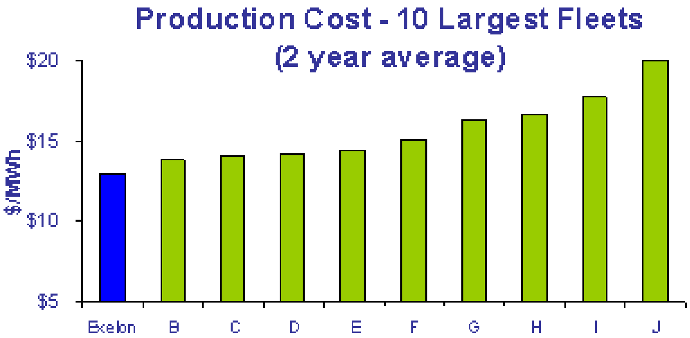
Nuclear Performance – Cost

Exelon capitalizes on its nuclear cost advantage

- Consistent improvement in production cost
- Industry leader in production cost by a substantial margin
- The size & scale of the fleet enables low-cost generation

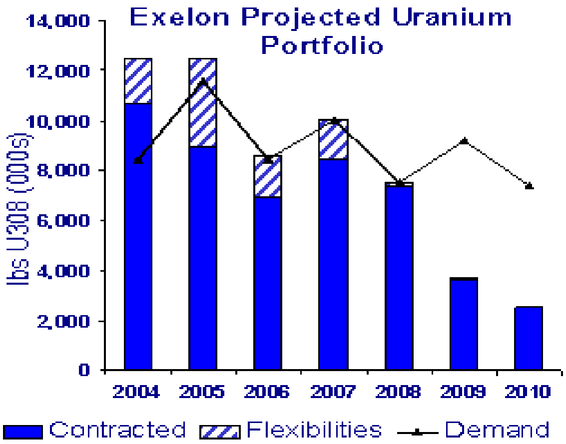
Exelon's low-cost nuclear generation is a competitive advantage

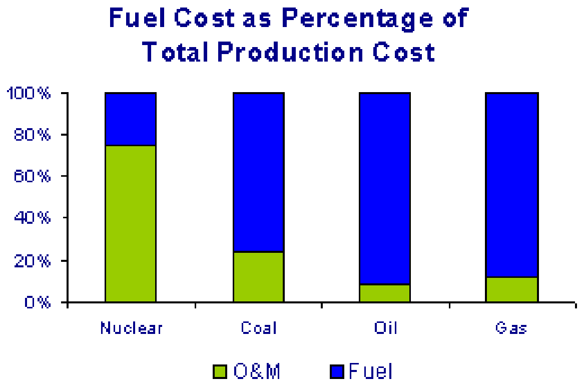


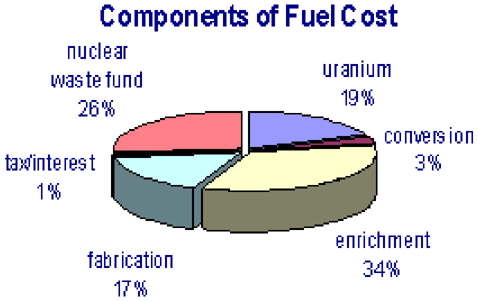


Data sources: Electric Utility Cost Group

Nuclear Performance – Fuel Costs







Uranium market prices have increased, but Exelon is managing its portfolio

- Reduced uranium consumption by 25%
- Contracting strategy protects us from increases through 2008
- Uranium is a small component of total production cost
- Expect long-term fundamentals in $20-25 range due to new uranium production

Exelon Nuclear is managing fuel costs

PSEG/Nuclear Operating Services Agreement

Exelon

- Nuclear Operating Services Agreement with Salem/Hope Creek is in place, fully functioning
  - 24 Exelon managers at the site full-time
  - Supported by transition team
  - Augmented by Exelon specialists providing assistance, assessments
- 2005 priorities defined: sharpened operational focus, equipment reliability, safety conscious work environment, meet financial commitments, successful refueling outages
- Performance to date:
  - Operations and work management processes improved; increased focus on plant equipment issues
    - Project reviews and reprioritization
    - Cost management processes installed
  - Salem generating well above plan; unit 2 refueling best ever
  - Hope Creek continues to experience equipment issues
- Support is structured to ensure no distraction from Exelon Nuclear fleet operations

Power Marketing

Ian P. McLean
President, Power Team

Exelon Investor Conference
New York City
August 5, 2005

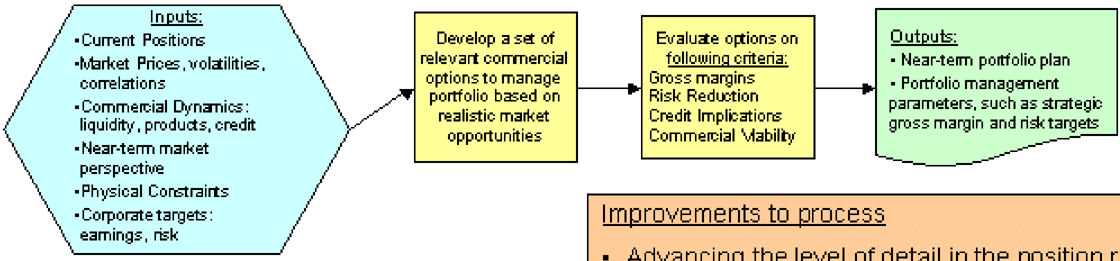
Power Team: Current State of the Portfolio

Exelon.

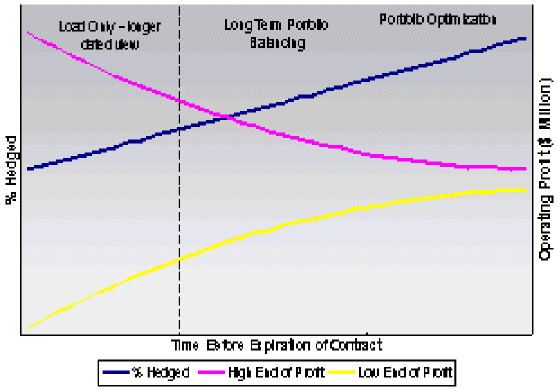
- We are taking advantage of beneficial market conditions
  - Power prices continue to rise
    - Driven by higher fuel prices and tightening fundamentals
    - Benefits our baseload generation
  - Improvements resulted from PJM expansion (ComEd and AEP control areas)
    - Transmission utilization efficiency
    - Forward market liquidity
  - Heat rates in ERCOT are moving higher
- Actively involved in and well positioned for market design changes
  - Capacity market reform in PJM
  - Post-2006 load auction in Illinois
  - Nodal market design in ERCOT

Note: See Appendix for 2004 – 2007 Historical and Forward prices (as of June 29, 2005)

Portfolio Management Process



Portfolio Management Over Time



Improvements to process

- Advancing the level of detail in the position reports
- Extending portfolio process to outer years as market liquidity increases

Timing of portfolio process

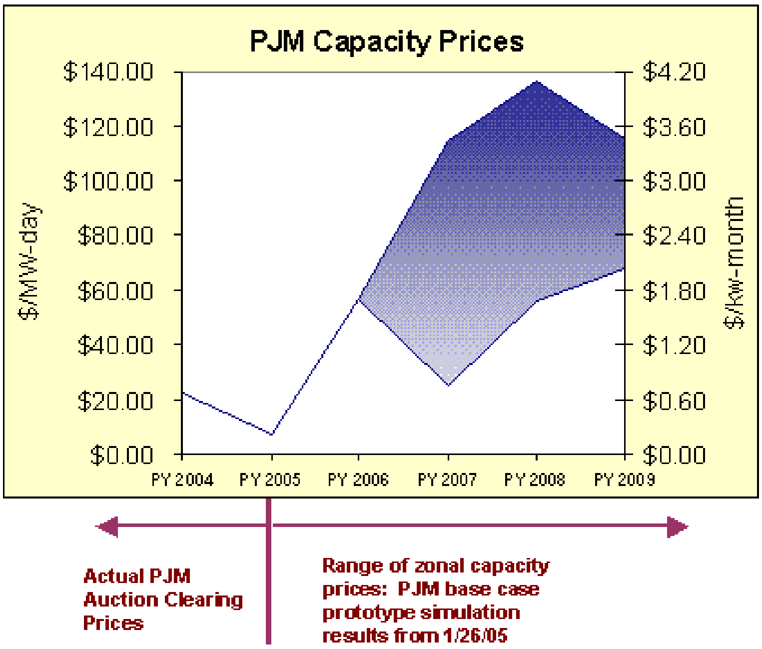
- Update the portfolio plan quarterly
- Monitor parameters weekly

Approach to managing volatility

- Increase percentage hedged as delivery approaches
- Have enough supply to meet peak load
- Cover options created by load obligations so that base load length can be sold
- Leave some length to spot for operational uncertainties and opportunistic sales
- Purchase Coal, Oil, and Natural Gas as power is sold

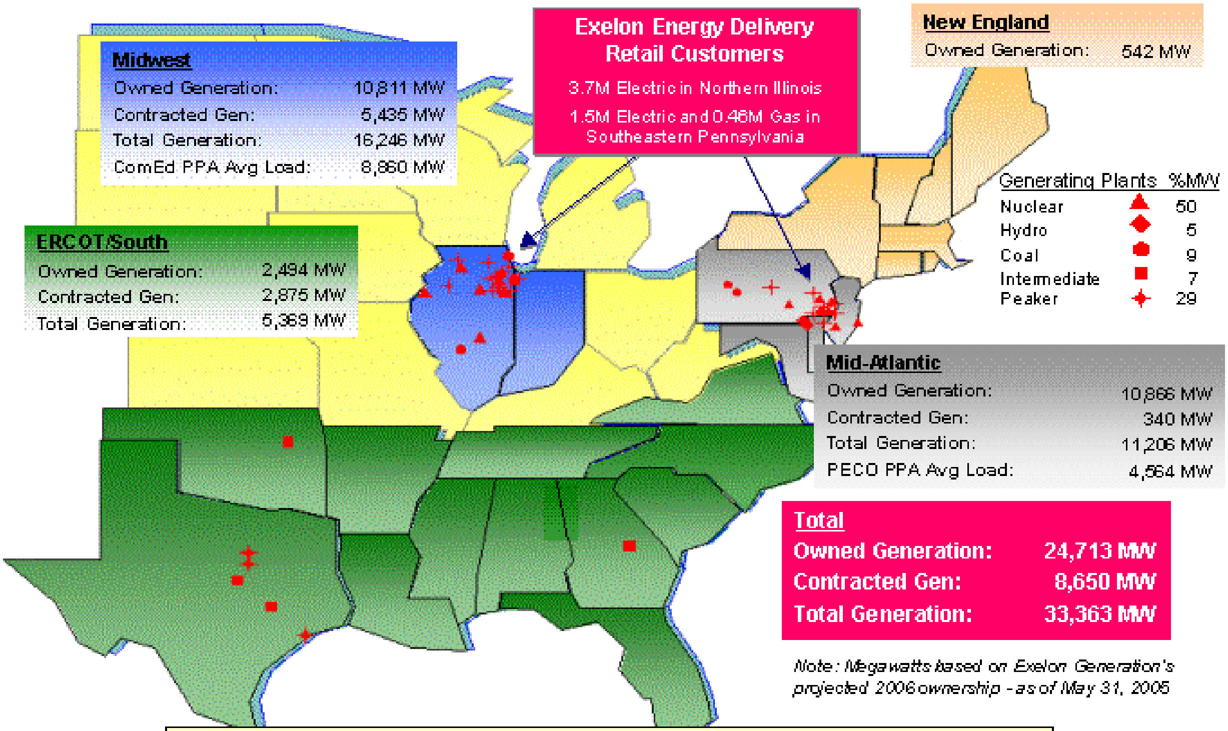
Recent RTO Initiatives

- Initiatives that will support continued reliability
  - Capacity Market Reform in PJM (Reliability Pricing Model-RPM)
    - Final stages of PJM stakeholder development
    - FERC recognizes current capacity construct needs reform
  - Energy and Capacity Market Reform in ERCOT
    - ERCOT is expected to adopt PJM-style Nodal Energy Market
    - Capacity Market reform is generating significant debate



PY = PJM Planning Year (June to May)

Our Regional Positions

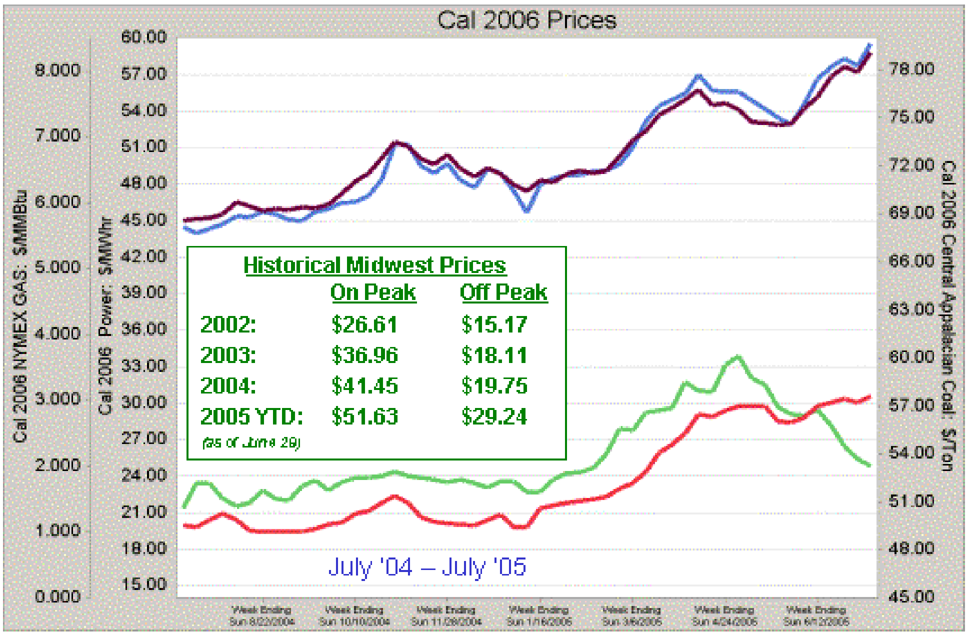


Note: Megawatts based on Exelon Generation's projected 2006 ownership - as of May 31, 2005

Exelon is positioned as a multi-regional, baseload producer with merchant activity in the South

Midwest: Market Dynamics

Exelon



- Cal 2006 NiHub On Peak
- Cal 2006 NiHub Off Peak
- Cal 2006 NYMEX Natural Gas
- Cal 2006 Central Appalachian Coal (without transportation)

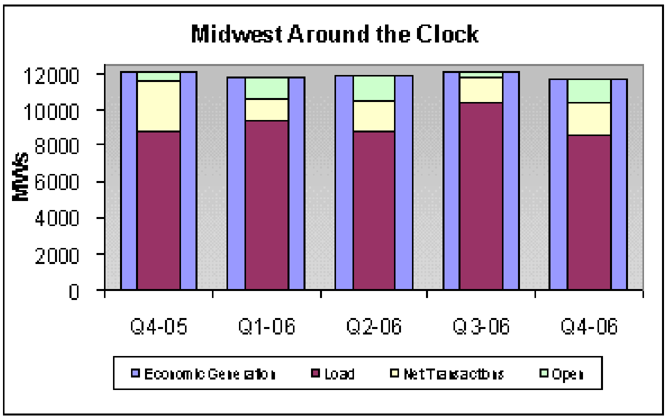
Cal = Calendar year

- PJM has increased liquidity in NiHub trading
- Rising fuel prices (Central Appalachian Coal, Natural Gas)
  - Pushing forward PJM NiHub prices higher
- Capacity prices
  - Cleared $6.91/MW-day for planning year '05/'06

Market dynamics are driving higher power prices in Northern Illinois

Midwest: Portfolio Characteristics

Generation Type	2006 Capacity (MW)	Avg. Variable Cost ($/MWHr)
Nuclear	10,515	$4.50
Coal	2,073	$20.00
Renewable	54	
Peakers	3,604	$100.00
Total Capacity	16,246	
PPA Annual Demand (GWHrs)	77,634	
PPA Average Load (MW)	8,860	
PPA Peak Load (MW)	17,915	

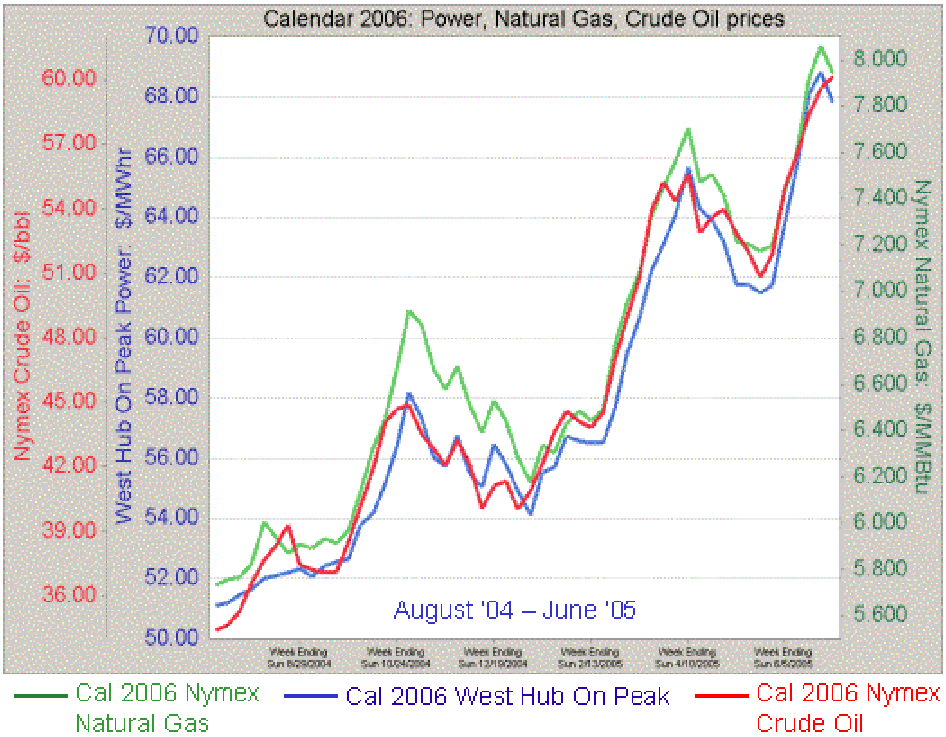


Portfolio Management

- **2005**
  - Balance of year hedged
    - Using power sales and daily power options
  - Coal requirements managed consistently with power sales obligations
- **2006**
  - RES migration 3,475 MW current planning year
    - Next planning year assumptions +/- 1,500 MW
    - Options are utilized to cover RES* switching risk
  - Acquiring load-following capability from the bilateral market to better match the assets with the load obligation
  - Balanced capacity position across PJM footprint
- **2007 and beyond**
  - Developing strategies for post 2006 load auctions
  - Currently hedging in Cal 2007 and 2008 markets

* RES = Retail Energy Supplier

East: Market Dynamics



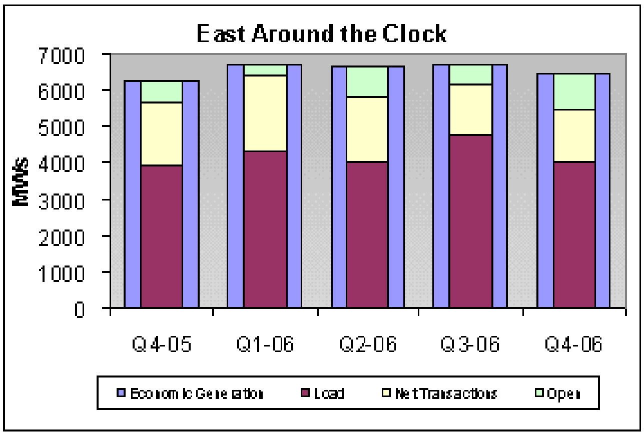
- CCGTs* on the margin for majority of on-peak hours
  - Natural gas prices drive power prices
- Minimal load switching
  - Due to economics
- Capacity market
  - Remains low through planning year '05/'06
  - PJM's capacity market design will drive prices

* CCGT = Combined Cycle Gas Turbine

Power prices are tracking closely to increasing fuel costs

East: Portfolio Characteristics

Generation Type	2006 Capacity (MW)	Avg. Variable Cost ($/MWHr)
Nuclear	5,766	$5.00
Coal	1,441	$35.00
Hydro	1,618	
Renewable	250	
Resid Oil, NG and Peakers	2,131	$75 resid oil $120 gas
Total Capacity	11,206	
PPA Annual Demand	39,983	
PPA Average Load (MW)	4,564	
PPA Peak Load (MW)	7,981	

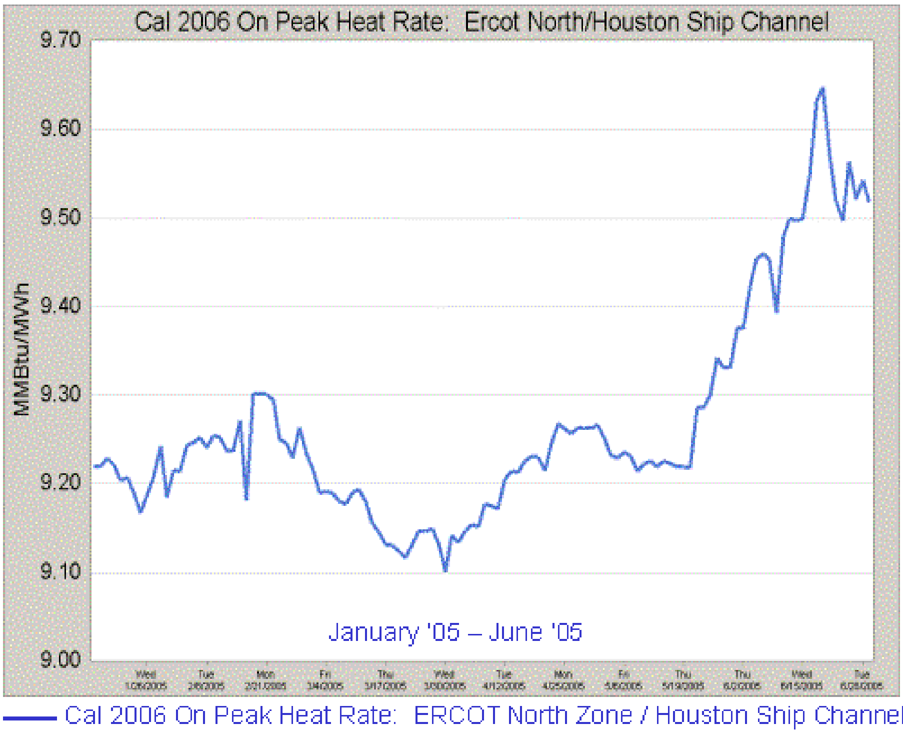


Portfolio Management

- **2005**
  - Well positioned for upside participation
    - Option strategies developed in power and fuels markets (Crude oil, residual oil, and natural gas)
- **2006**
  - Acquiring load-following capability from bilateral market to better match assets with the load obligation
  - Oil and natural gas requirements acquired and shaped to meet our seasonal obligations
  - Active participation in the PJM FTR* auctions
    - Managing congestion risks associated with delivering power to sales and load obligations
- **2007 and beyond**
  - Developing strategies for potential mitigation scenarios associated with the merger
    - Manage remaining baseload position and intermediate needs

* FTR = Financial Transmission Right

ERCOT/South: Market Dynamics

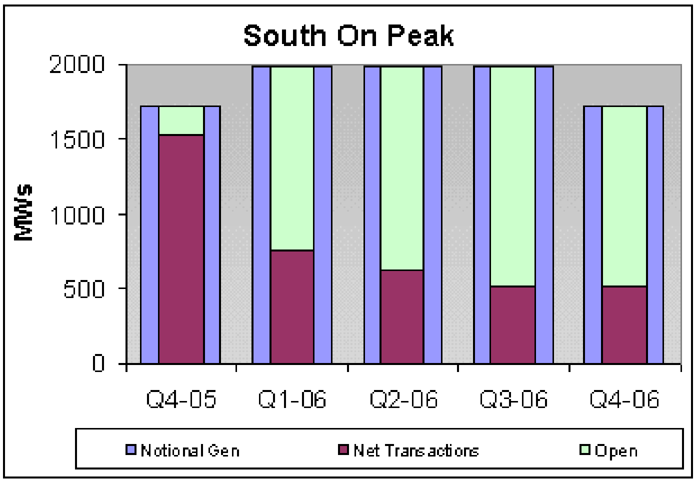


- Gas is on the margin
- Spark spread determines our merchant profitability
- Recent announcements over two-year horizon
  - Over 7,000 MW of mothballed generation
  - Over 1,500 MW of retiring generation

Expected margin for efficient combined cycle generation has increased 30% in the past quarter

ERCOT/South: Portfolio Characteristics

Generation Type	2006 Capacity (MW)	Avg. Variable Cost ($/MWHr)
Combined Cycle	1,975	$65.00
Peakers	3,394	$100.00
Total Capacity	5,369	



Note: Position does not include high heat rate units or the call option sales against them

Portfolio Management

- **2005**
  - Participated in upward heat rate movement for summer by holding extra length
  - Capture margin when peakers called by ERCOT for local reliability by having physical gas supply available
- **2006**
  - Active hedging program in 2006; scale selling into higher markets
  - Daily call option sales over the summer will be managed by using a combination of market-based products and our high heat rate units
- **2007 and beyond**
  - Developing hedge strategies in preparation for a nodal market design
  - Markets are being quoted for individual nodal points in the forward market, but a trading hub has yet to develop

Portfolio Sensitivities for Generation Co.

Gas Price Sensitivity [1] ($ million pre-tax)	Gas +20%	Gas -20%
Sep to Dec 2005	$7	($2)
Calendar 2006	$56	($46)
Power Price Sensitivity [2] ($ million pre-tax)	**Power +$1.00 ATC***	**Power -$1.00 ATC***
Sep to Dec 2005	$4	($3)
Calendar 2006	$28	($27)

* ATC = Around the Clock

Notes:

[1] Gas prices were changed with a correlated change in power, oil, and coal prices

[2] Power prices were changed; fuel prices were held constant

Appendix

Power Marketing

Current Market Prices

	2004	2005[1]	2006	2007
PRICES (as of June 29)				
PJM West Hub ATC ($/mwhr)	$42.35[2]	$49.02	$53.75	$52.54
PJM NiHUB ATC ($/mwhr)	$30.15[3]	$39.82	$42.78	$41.23
NEPOOL MASS HUB ATC ($/mwhr)	$52.13[2]	$63.40	$70.32	$68.24
ERCOT North On Peak ($/mwhr)	$49.53[4]	$64.85	$73.26	$70.54
Henry Hub Natural Gas ($/mmbtu)	$5.85[4]	$7.03	$7.88	$7.53
WTI Crude Oil ($/bbl)	$41.48[5]	$54.70	$59.78	$58.44
On Peak Heat Rates (mmbtu/mwhr) (as of June 29)				
West Hub / Tetco M3	7.57	7.88	7.66	8.02
NiHub / Chicago City Gate	7.18	7.57	7.30	7.46
ERCOT North / Houston Ship Channel	8.68	9.43	9.54	9.58

1. 2005 information is a combination of actual prices through June 29th and market prices for the balance of the year
2. Real Time LMP (Locational Marginal Price)
3. Next day market through April 30, LMP from May to Dec
4. Next day over-the-counter market
5. Average NYMEX settle prices

Merger & Federal Regulatory Update

Elizabeth A. Moler
Executive Vice President, Government and Environmental Affairs and Public Policy

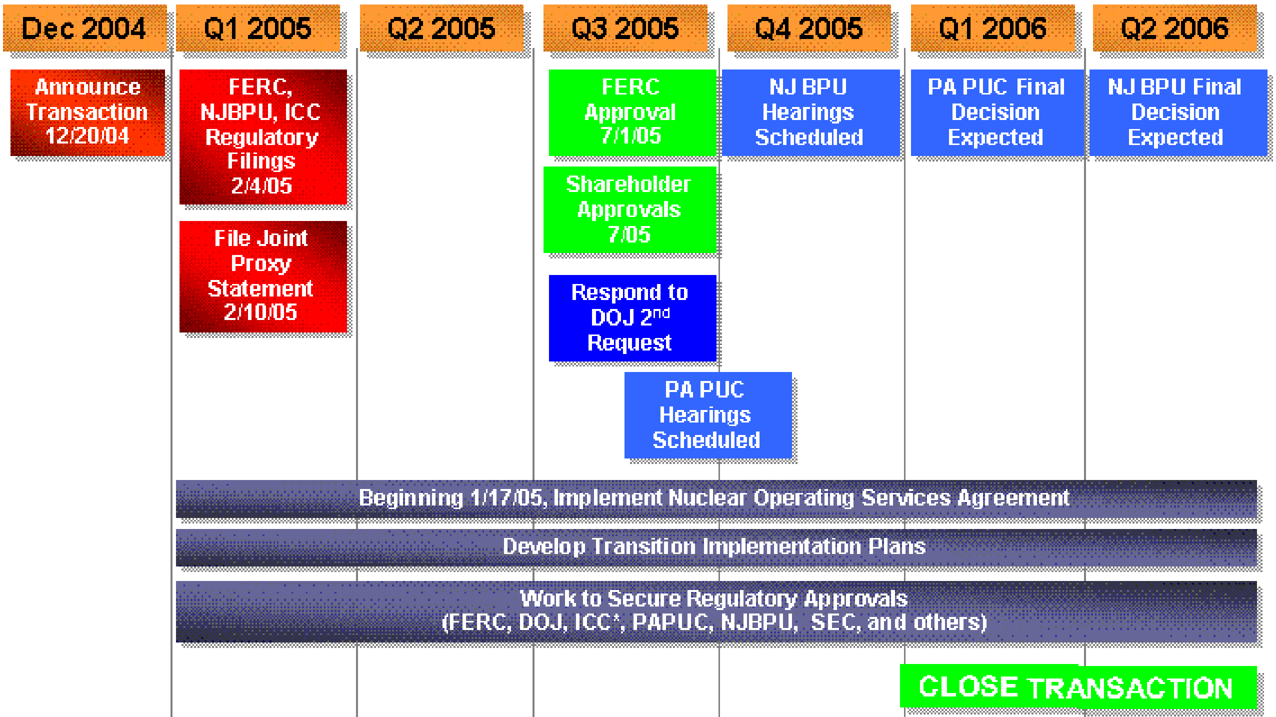
Exelon Investor Conference
New York City
August 5, 2005

Merger Regulatory Update

Status of major filings/approvals:

- **FERC Order Approving Merger Without Hearing Issued 7/1/05**
  - FERC approved our application as proposed with no surprises
  - New merger review provisions in energy bill do not apply
- **DOJ Hart-Scott-Rodino Review**
  - Both companies have certified substantial compliance with the second request for information
  - We anticipate the waiting period will expire September 1
  - DOJ review will continue thereafter, but is not expected to delay closing
- **Pennsylvania**
  - Company rebuttal testimony now filed
  - Schedule being revised; hearings now planned for September/October
  - Final decision expected in January, unless we settle earlier
- **New Jersey**
  - Schedule being revised; hearings now planned for late November/December
  - Final BPU decision expected in May, unless we settle earlier
- **SEC**
  - PUHCA repeal will be effective ~ Feb. 4
  - No PUHCA order needed unless we close before then

Anticipated Timeline



* Notice filing only

Domenici-Barton Energy Policy Act of 2005

Major Provisions of Importance to Exelon:

- Electricity
  - PUHCA Repeal
  - FERC Authority to Establish Mandatory Electric Reliability Standards
  - FERC Transmission Line Siting Authority
  - Transmission Pricing Incentives
- Nuclear
  - Sets Stage for New Nuclear Plants
  - Price-Anderson Renewal, Loan Guarantees, Standby Coverage
- Tax
  - Nuclear Decommissioning Trust Fund Reform
  - Accelerated Depreciation for Transmission, Natural Gas Assets

Illinois Regulatory/Legislative Update

Anne R. Pramaggiore
Vice President, Regulatory and Strategic Services, ComEd

Exelon Investor Conference
New York City
August 5, 2005

A Retrospective: Milestones August 2004 – August 2005

- **September 23, 2004:** ICC Workshop Procurement Working Group submitted its consensus report to the ICC Staff setting out 18 features of optimal Illinois procurement model
- **December 29, 2004:** ICC Staff submitted report to the ICC recommending "Reverse Auction"
- **January–May 2005:** House Electric Deregulation Oversight Committee conducted hearings
- **February 2005:** ComEd and Ameren filed procurement cases at ICC proposing "Reverse Auction" as procurement method post transition
- **April 2005:** Proposed amendment to the Illinois Public Utilities Act to extend the current transition period for two more years failed to pass the House Electric Deregulation Oversight Committee
- **May 17, 2005:** Attorney General (AG) filed motion to dismiss ComEd and Ameren "Reverse Auction" cases
- **June 1, 2005:** ICC Administrative Law Judge (ALJ) denied AG's motion to dismiss
- **June 8, 2005:** Intervenors filed testimony in ComEd procurement case with 11 of 14 parties supporting some form of auction
- **June 22, 2005:** AG filed an interlocutory appeal to ICC for reversal of ALJ's ruling
- **July 13, 2005:** ICC affirmed ALJ's decision to deny AG's motion to dismiss by 5 – 0 vote

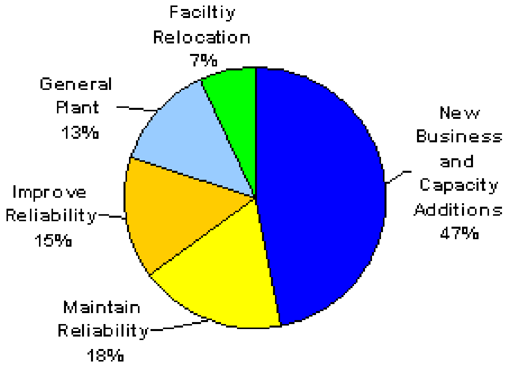
Through workshop process and ICC case, strong support for “Reverse Auction” has developed; AG, Citizens Utility Board (CUB), Cook County State’s Attorney’s Office (CCSAO) remain outlyers

Current Status: Procurement Case

- **June 8th intervenor filing demonstrated strong support for an Illinois "Reverse Auction"**
  - 11 of the 14 case participants support "Reverse Auction" or variation thereof
    - Support from retail and wholesale community, large consumers and ICC Staff
    - Opposition from CUB, AG, CCSAO who call for a return to cost-based ratemaking
- ComEd and Ameren agreed to modifications in rebuttal testimony:
  - 35% load cap
  - 50 MW tranche size
  - Switching between ComEd and Ameren on like products
  - Auction to be held by ComEd and Ameren within first 10 days of September
  - Staff to adopt stronger, more visible role in auction process, enhancing consumer protection features of process

Looking Forward: Delivery Services Case

- Late August Filing
- Vital statistics:
  - Delivery Services Tariff (DST) case driven by infrastructure improvements
  - $1.89B revenue requirement
  - $3.0B gross rate base increase



- ComEd expects DST overall rate impact to mass market customers to be approximately 5% increase

Looking Forward: Upcoming Activities

Exelon

ComEd Procurement Case

• August 19, 2005:	ComEd surrebuttal
• August 29 – September 9, 2005:	Hearings
• October – November 2005:	Legislature's veto session
• November 2005:	ALJ proposed order
• January 24, 2006:	ICC final order
• January – May 2006:	Spring legislative session
• September 2006:	First auction is conducted
• January 2007:	New rates go into effect

ComEd Delivery Services Case

• Late August 2005:	ComEd files case
• February – March 2006:	Hearings
• May – June 2006:	ALJ proposed order
• July 2006:	ICC final order
• January 2007:	New rates go into effect

Exelon

Financial Overview

John F. Young
Executive Vice President, Finance and Markets

Exelon Investor Conference
New York City
August 5, 2005

Financial Overview

- 2005 Performance and Outlook
- 2006 Guidance (stand-alone)
- Ongoing Earnings Drivers (stand-alone)
- Deploying our cash
- Key credit measures
- Merger Update

Year-To-Date Results

(EPS in $)		Jun-05		Jun-04
Adjusted (non-GAAP) Operating EPS	$	1.42	$	1.31
GAAP EPS	$	1.53	$	1.40

First Half 2005 Highlights:

- Pension funding
- Sithe exit
- Favorable weather
- Strong generation margins

Strong first half: 8% growth in operating earnings; GAAP earnings continue to exceed operating earnings

Note: See presentation appendix for adjusted (non-GAAP) operating EPS reconciliations to GAAP.

Year-To-Date Earnings Drivers

Exelon

Operating Earnings		Actual vs. Prior Year YTD
2004 Actual		**$ 1.31**
Profit Drivers:		
Genco RNF (net of PPA impact)		0.13
Pension Expense		0.02
Interest Expense		0.04
Decommissioning Trust Rebalancing - AmerGen		0.03
Loss Drivers:		
Energy Delivery RNF (net of PPA impact):		
- Weather	0.03	
- Transmission Revenue (SECA)	(0.02)	
- Ancillary Services	(0.04)	(0.03)
Planned Nuclear Refueling Outages		(0.02)
Asbestos Reserve		(0.04)
Share Dilution		(0.02)
2005 Actual		**$ 1.42**

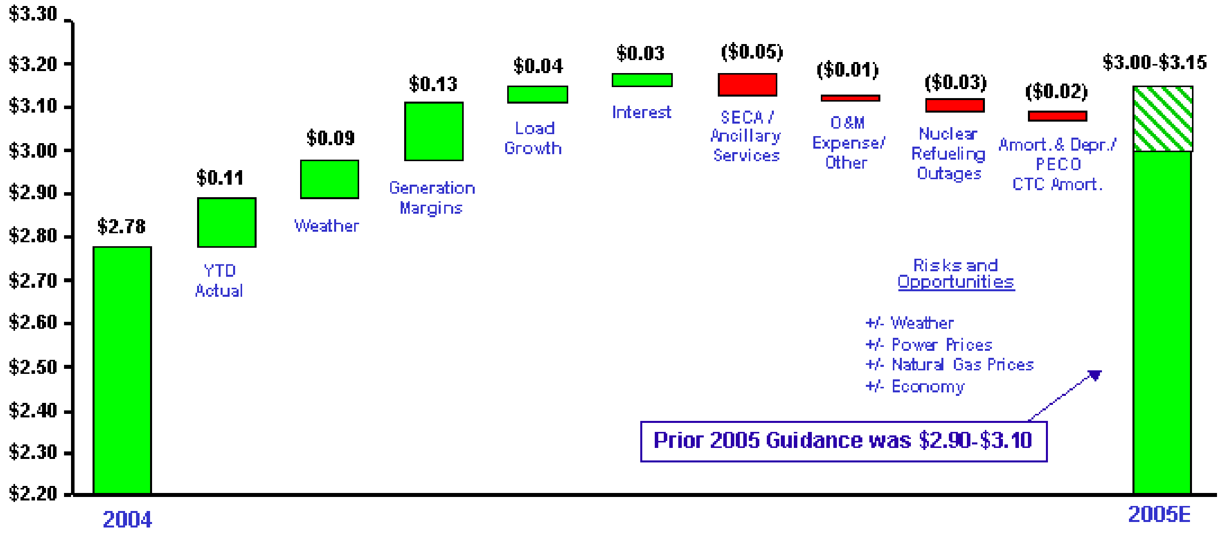
Higher generation margins drove earnings growth YTD

Notes: RNF = Revenue net Fuel/Purchased power; PPA = Purchase Power Agreement; SECA = Seams Elimination Charge/Cost Assignment. See presentation appendix for adjusted (non-GAAP) operating EPS reconciliation to GAAP.

2005 Adjusted (non-GAAP) Operating EPS

Revised Guidance: $3.00 - $3.15

Expected EPS Drivers

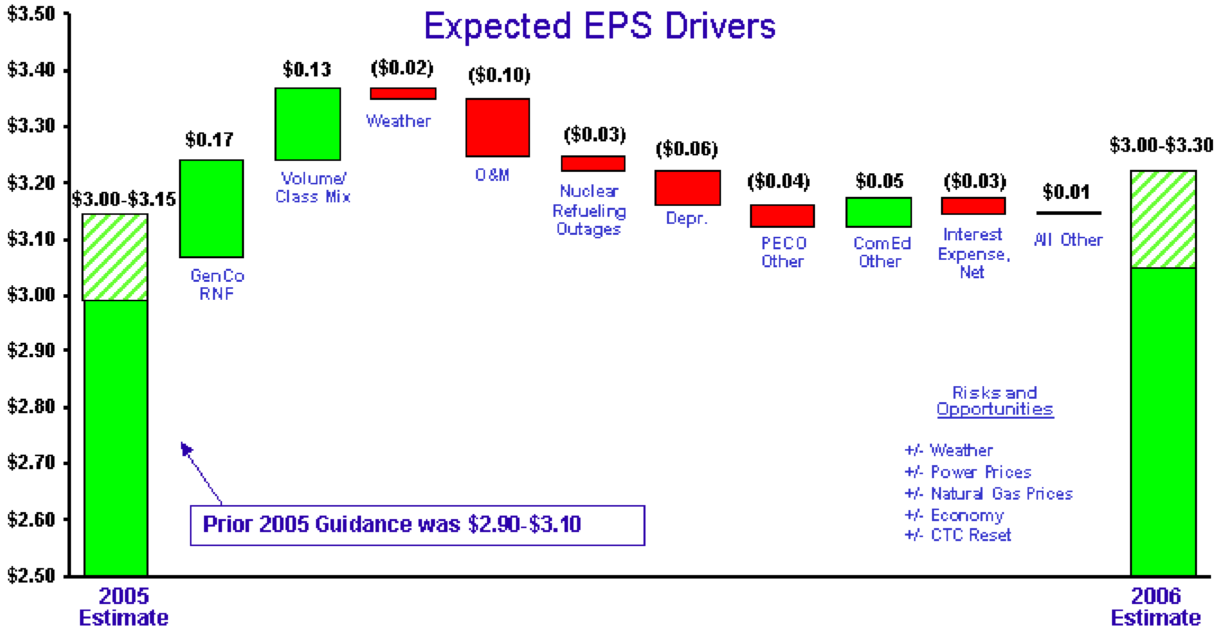


Favorable weather comparables and generation margins driving earnings growth for balance of year

Note: See presentation appendix for reconciliation to GAAP reported EPS.

2006 Adjusted (non-GAAP) Operating EPS – Stand-alone

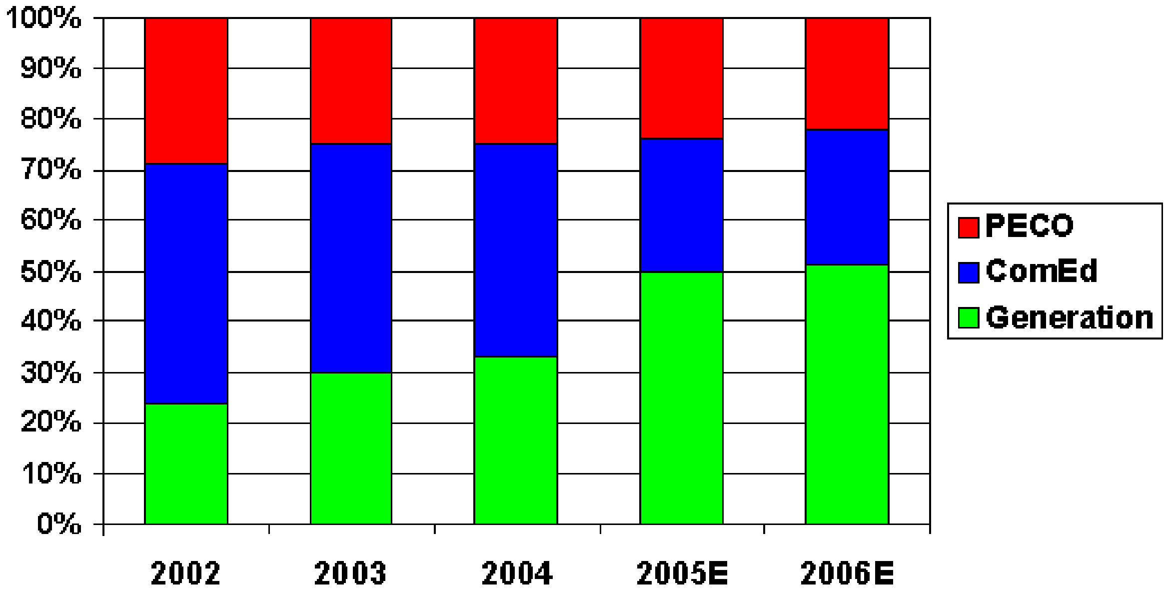
Guidance: $3.00 - $3.30



Higher generation margins and normal load growth, partially offset by higher O&M costs, will continue to drive earnings growth in 2006

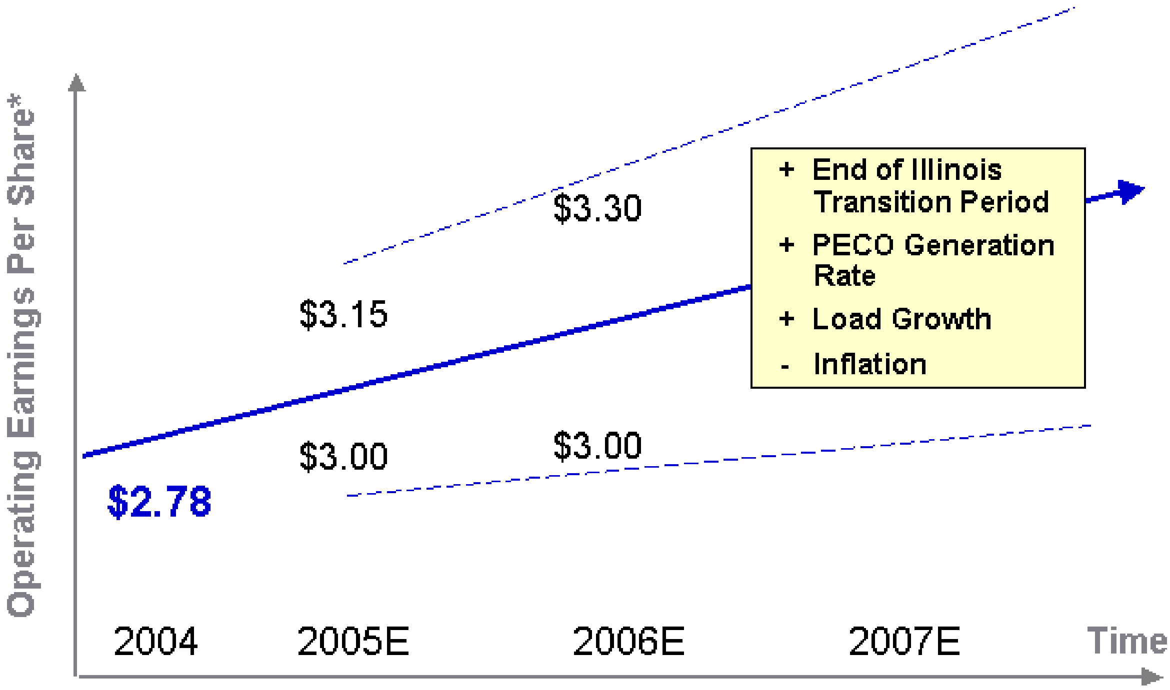
Note: See presentation appendix for reconciliation to GAAP reported EPS.

Composition of Operating Earnings



A further shift in relative earnings contribution from Energy Delivery to Generation will occur in 2007 when ComEd becomes a pure wires company and Generation gets a market price for its Midwest production

Ongoing Earnings Drivers – Stand-alone



Strong growth expected 2006 – 2007, primarily driven by end of frozen rates in Illinois

* Note: See presentation appendix for reconciliation to GAAP reported EPS.

End of Illinois Transition Period

Exelon

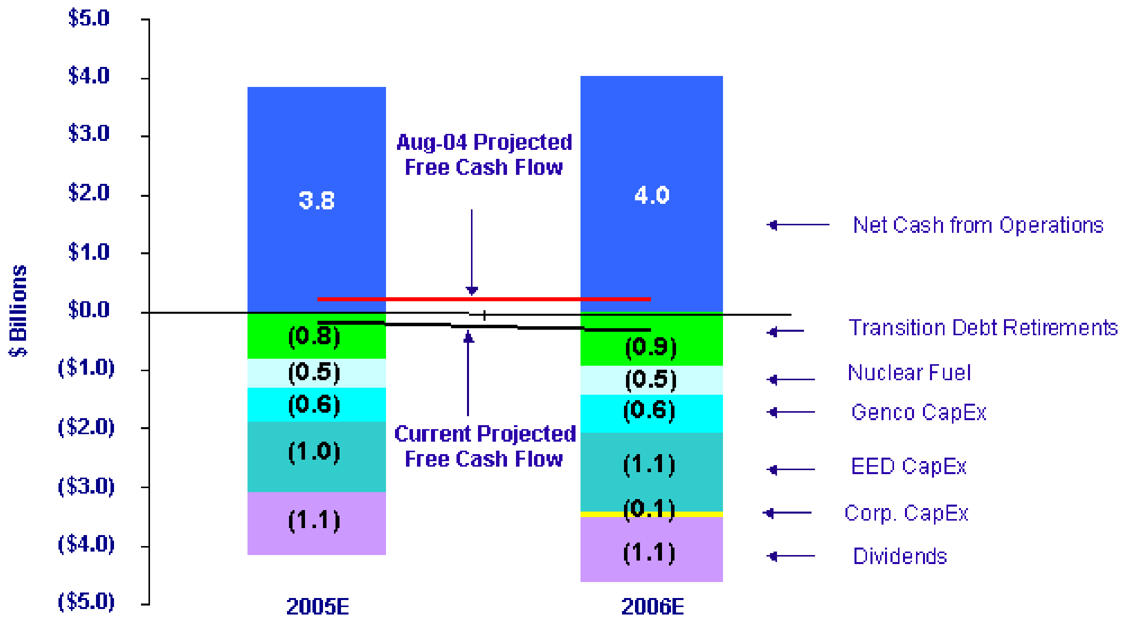
- **ComEd becomes a pure wires business**
  - Returns determined through traditional regulatory processes
  - No generation margin
  - Rate increase expected on delivery services tariff (DST)
- **Exelon Generation gets a market price for all its Midwest production**
  - Approximately 90 TWh nuclear and 10 TWh coal
  - About 2/3 of which is currently supplied to ComEd at a discount to today's market price
- **Composition of earnings shifts from ComEd to Generation**

	ComEd	Genco	Exelon
Generation Margin	-	+	+
DST	+	N/A	+
Net Earnings Impact	-	+	+

- **ComEd is willing to work with stakeholders to mitigate the potential customer impacts of transitioning to market prices for generation**

Net Impact on earnings is expected to be positive for Exelon overall

Deploying Our Cash



Our current cash flow forecast reflects increased investments in the core business – mainly on the regulated side

Note: Net Cash from Operations includes cash from normal operations, decommissioning investment, and debt issued for pension funding in 2005. See presentation appendix for definition of Free Cash Flow.

Projected 2005 Key Credit Measures

Exelon

Exelon stand-alone:

			Credit Ratings[1] S&P/Moody's/Fitch
Exelon consolidated:	FFO / Interest	7.5x	BBB+/Baa2/BBB+
	FFO / Debt	39%	
	Debt Ratio	48%	
Generation:	FFO / Interest	13.6x	A-/Baa1/BBB+
	FFO / Debt	87%	
	Debt Ratio	29%	
ComEd:	FFO / Interest	5.7x	A-/A3/A-
	FFO / Debt	27%	
	Debt Ratio	41%[2]	
PECO:	FFO / Interest	12.6x	A-/A2/A
	FFO / Debt	36%	
	Debt Ratio	45%	

Exelon's Balance Sheet is strong

Notes: Exelon consolidated, ComEd and PECO metrics exclude securitization debt. See presentation appendix for FFO (Funds from Operations)/Interest and and FFO/Debt reconciliations to GAAP.

[1] Senior unsecured ratings for Exelon consolidated and Generation and senior secured ratings for ComEd and PECO

[2] Assumes half of ComEd goodwill is written off

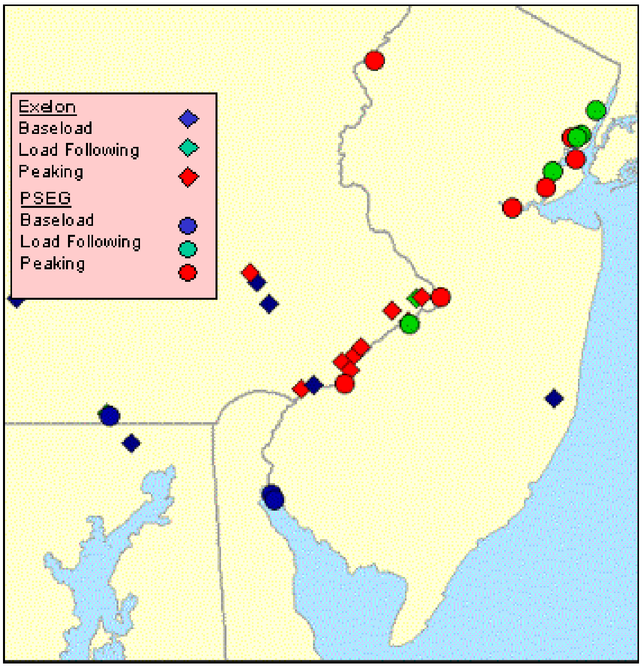
Market Concentration Mitigation

Exelon

2/4/05 – Filed the merger application with FERC
6/30/05 – FERC approved merger

Divestiture Plan

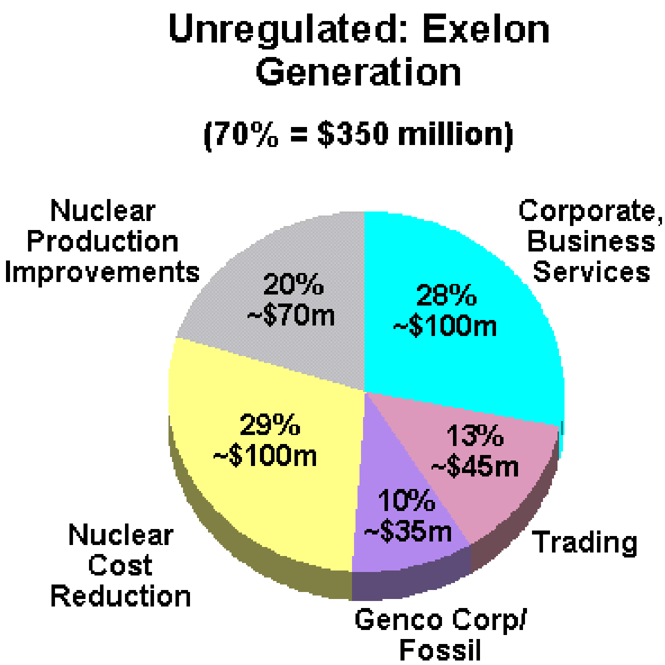
- Must complete within 12 months
- Divest a total of 4,000MW fossil fuel facilities
  - Peaking: 1,200MW
  - Mid-Merit: 2,800MW
    - at least 700MW coal-fired
- "Virtual Divestiture"
  - Transfer control of 2,600MW of baseload nuclear energy

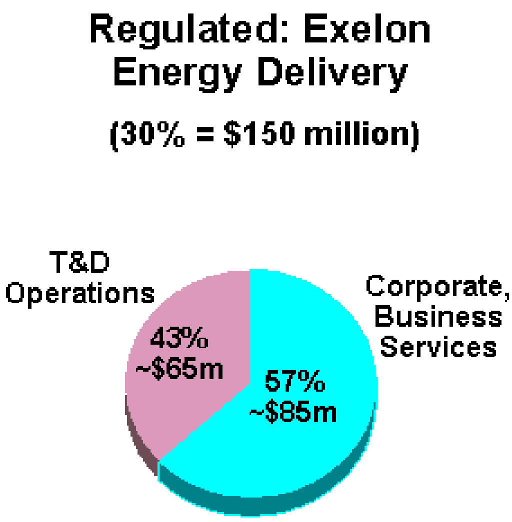


We believe our FERC-approved mitigation plan fully addresses all market concentration issues

PSEG

$500 Million of Synergies Beyond Year 1





Synergies are mostly unregulated and are backed-up by detailed execution plans

Note: Regulated synergies reflect February 4, 2005 testimony.

Financial Benefits of Merger

- Stronger platform to achieve consistent earnings growth
- Improved performance of PSEG nuclear plants – already providing benefit for both companies through Nuclear Operating Services Agreement
- Synergies of $500 million beyond year 1, mostly in unregulated generation business
- Earnings accretion for each company's shareholders in year 1
- 14% higher dividend for Exelon shareholders; PSEG shareholders kept whole
- Strong balance sheet

The merger is operations-driven with strong financial benefits for both Exelon and PSEG shareholders

Summary

Stand-alone

- Raising 2005 earnings guidance to reflect strong first half
- Earnings growth in 2006 driven by higher generation margins, partially offset by higher costs
- Earnings growth in 2007 driven by end of frozen rates in Illinois
- Relative earnings contribution shifting from Energy Delivery to Genco
- Cash flow forecast reflects reinvestment in business – mainly on regulated side
- Balance sheet strong enough to fund projected investments and continue to grow the dividend

Merger

- FERC-approved market concentration mitigation plan in place
- Detailed line of sight to synergies

History of delivering on commitments

Appendix

Financial Overview

Exelon Consolidated

GAAP Earnings to Adjusted (non-GAAP) Operating Earnings - YTD

(in Millions, except EPS)

	YTD2005			YTD2004		
	GAAP	Adjustments	Operating Earnings	GAAP	Adjustments	Operating Earnings
Operating revenues	$ 7,045	$ -	$ 7,045	$ 7,073	$ (248) (e)	$ 6,825
Fuel & purchased power	2,331	57 (a),(b)	2,388	2,548	(244) (a),(e)	2,304
Revenue Net Fuel	4,715	(57)	4,658	4,525	(4)	4,521
Operating & maintenance	1,893	(49) (b),(c),(d),(h)	1,844	1,918	(127) (b),(e),(h)	1,791
Depreciation & amortization	644	(37) (b),(d)	607	612	(27) (b),(e)	585
Taxes other than income	349	-	349	371	(9) (e)	362
Total operating expenses	2,887	(86)	2,801	2,901	(163)	2,738
Operating income	1,828	29	1,857	1,624	159	1,783
Interest expense	(399)	8 (b)	(391)	(433)	14 (b),(e)	(419)
Equity in Earnings	(68)	56 (b)	(12)	(65)	23 (b)	(32)
Other, net	97	-	97	146	(90) (e)	56
Income from continuing operations, pre-tax	1,458	93	1,551	1,282	106	1,388
Income taxes	435	156 (a),(b),(c),(d),(h)	591	382	133 (a),(b),(c),(e),(h)	515
Income from continuing operations	1,023	(63)	960	900	(27)	873
Gains (losses) from discontinued operations	12	(15) (d)	(3)	1	-	1 (g)
Cumulative effect of a change in accounting	-	-	-	32	(32) (f)	(0)
Net income	$ 1,035	$ (78)	$ 957	$ 933	$ (59)	$ 874
Earnings per share (diluted)	$ 1.53		$ 1.42	$ 1.40		$ 1.31

(a) Adjustment to exclude the mark-to-market impact of Exelon's non-trading activities (primarily at Generation).
(b) Adjustment to exclude the financial impact of Exelon's investments in synthetic fuel-producing facilities.
(c) Adjustment to exclude costs associated with Exelon's anticipated merger with Public Service Enterprise Group Inc.
(d) Adjustment to exclude the 2005 financial impact of Generation's investment in Sithe Energies, Inc.
(e) Adjustment to exclude the 2004 financial impact of Boston Generating, LLC.
(f) Adjustment for the cumulative effect of adopting FIN No. 46-R.
(g) Includes the 2004 financial impact of Enterprises.
(h) Adjustment to exclude severance charges.

Note: Items may not add due to rounding.

Consolidated – Key Assumptions

	2004A	2005E	2006E
Nuclear Capacity Factor (%)[1]	93.5	93.9	92.9
Total Genco Sales Ex Trading (GWhs)	202,599	220,700	193,700
Total Sales to Energy Delivery (GWhs)	110,465	119,400	118,700
Total Market and Retail Sales (GWhs)	92,134	101,200	75,000
Volume Retention (%)			
PECO	88	94	95
ComEd	77	79	76
Delivery Growth (%)[2]			
PECO	3.8	0.2	2.6
ComEd	3.3	1.2	2.2
Elec. Wholesale Mkt. ATC Price ($/MWh)			
PJM Midwest (NiHUB)	31.15	40.00	43.00
PJM Mid-Atlantic (West Hub)	42.34	49.00	54.00
Effective Tax Rate (%)	36.5	37.5	37.5

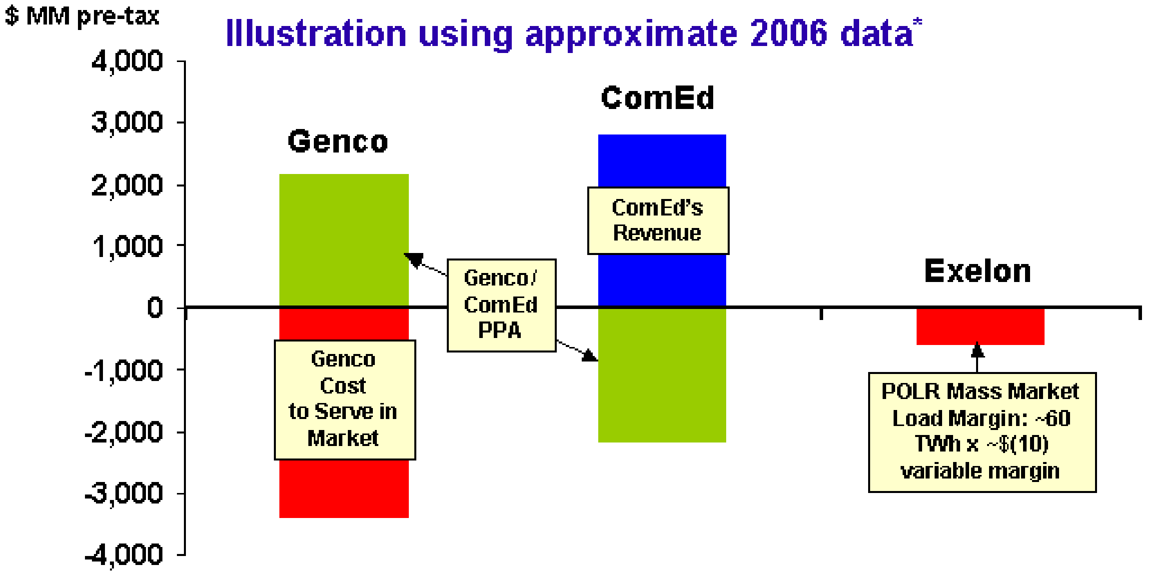
Note: Data for Exelon stand-alone

A= Actual; E = Estimate; ATC = Around the clock

(1) Excludes Salem

(2) Weather Normalized

Serving ComEd's Mass Market Load Obligation



* Assumes 60 TWh ComEd POLR Mass Market Load in 2006, $36 Genco/ComEd PPA price, $57/MWh cost-to-serve and $47/MWh implied average revenue in current bundled tariff. Mass Market represents residential and small commercial and industrial customer classes (<1 MW).

The end of frozen rates in Illinois in 2007 means the end of serving ComEd's POLR obligation at a discount to the expected market price

Note: POLR = Provider of Last Resort

ComEd Delivery Services Investments

($ in Millions)	2000	2004*	Chg.
Distribution Rate Base	$ 3,617	$ 5,355	48%
Weighted Average Cost of Capital - 2004 estimated	9.0%	8.7%	
After Tax Rate Base Return Requirement	269	410	
Gross Revenue Conversion Factor	1.67	1.66	
Authorized Return Grossed Up for Taxes	$ 448	$ 680	
Operating Expenses before Income Taxes	1,115	1,280	15%
Total Delivery Service Revenue Requirement	1,563	1,960	25%
Less: Delivery Service Revenues Provided by Other Tariffs	55	84	53%
Revenue Requirement	$ 1,508	$ 1,876	24%

Overall requested system Delivery Services Tariff rate increase expected to be about 15%; reflects increases in sales volumes due to load growth and changes in customer class sales mix since 2000

The end of frozen rates in Illinois in 2007 means ComEd can earn a fair return on its distribution investments

* Based on actual GAAP data. Reflects 42%/58% debt/equity ratios (including goodwill and transition debt). Assumes 10.5% ROE. Financial data is simplified and rounded for illustrative purposes.

Estimated 2004 ComEd Distribution ROE

Exelon

		($M)
A	Estimated 2004 DST Revenue *	1,574
B	Revenue Requirement	1,876
C	Over/(Under) Earning (A-B)	(302)
D	2004 Rate Base	5,355
E	2004 Common Equity Ratio	58%
F	Estimated Regulatory Equity (D*E)	3,106
G	Estimated ROE Shortfall (C*(1-40%)/F)	-5.8%
H	Assumed ROE	10.5%
I	Estimated 2004 ROE on Distribution (G+H)	4.7%

* Assumes all ComEd customers are served under the current DST rate.

ComEd Transmission Investments

($ in Millions)	2004
Transmission Rate Base	$ 1,276
Weighted Average Cost of Capital - 2004 estimated	8.7%
After Tax Rate Base Return Requirement	98
Gross Revenue Conversion Factor	1.66
Authorized Return Grossed Up for Taxes	$ 163
Operating Expenses before Income Taxes	142
Total Estimated Transmission Revenue Requirement	$ 305

Note: Financial data is simplified and rounded for illustrative purposes.

ComEd Goodwill

- **Impairment assessment performed at least annually (4th quarter) to determine if estimated fair value (FV) of ComEd supports recorded goodwill**
  - Assessment uses discounted cash flow analysis to estimate FV
    - Dependent on variables including interest rates, utility sector market performance, market power prices, post-2006 rate/regulatory structures, operating and cap ex requirements
  - Assessment performed in two steps:
    - Step 1: Compare FV of ComEd to its book value (BV) including goodwill – if FV exceeds BV, no impairment; if not, then go to Step 2
    - Step 2: Compare FV of goodwill to BV of goodwill – if FV exceeds BV, no impairment; if not, an impairment loss is reported as reduction to goodwill and charged to operating expense
- **Goodwill impairment has no cash flow impact**
- **No impairment recorded at ComEd to date, but reasonable possibility goodwill will be impaired going forward**
- **Any future impairment charges at ComEd will likely be offset in Exelon's consolidated results**
  - Impairment test at Exelon level considers cash flows of entire EED segment, including both ComEd and PECO; PECO has no goodwill and its estimated FV substantially exceeded its BV under the 2004 test
- **Goodwill impairment has no impact on ComEd's ROE rate cap during the transition period through 2006**
- **Impact on ComEd distribution rate case:**
  - Goodwill not included in rate base (no return of goodwill)

ComEd Balance Sheet/Capital Structure

	12/31/03		12/31/04		Projected 12/31/05(1)	
	$ in Billions	% of Total Cap.	$ in Billions	% of Total Cap.	$ in Billions	% of Total Cap.
Goodwill	4.7	-	4.7	-	2.4	-
Debt	6.4	50%	4.9	42%	4.6	47%
Common Equity	6.3	50%	6.7	58%	5.2	53%
Debt(2)	4.8	43%(2)	3.5	34%(2)	3.6	41%(2)
Common Equity	6.3	57%(2)	6.7	66%(2)	5.2	59%(2)

(1) Assumes a scenario where one-half of goodwill is written off and $0.3B securitization debt matures in 2005.
(2) Excludes securitization debt from total debt and total capitalization.

Market Concentration Mitigation

Exelon

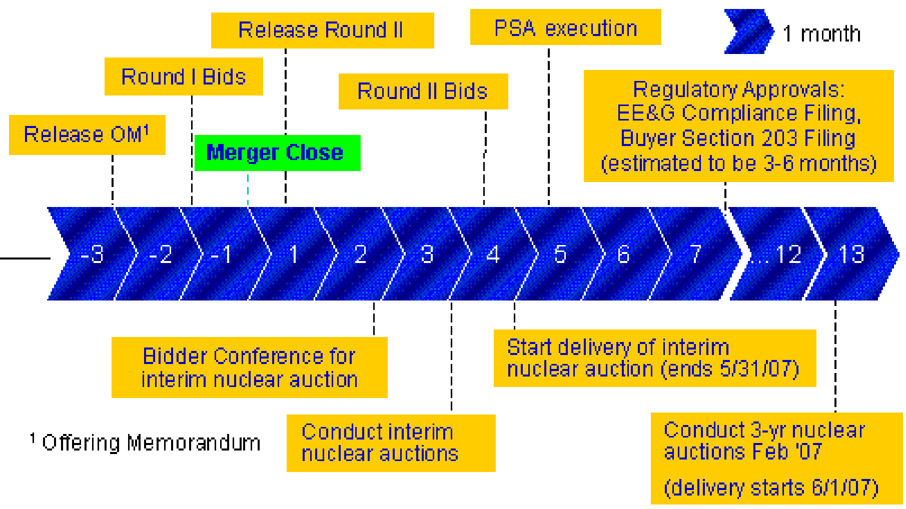
Fossil Divestiture

- **Selected Merrill Lynch as advisor**
- **DOJ approval pending**
- **2-round RFP process**
- **Target purchase and sales agreement (PSA) within 6 months of merger close**
- **Interim mitigation in place on merger close**

Virtual Divestiture

- **Compliance filing on Auction Manager/ Monitor filed 8/1/05**
- **DOJ approval pending**
- **In final stages of Auction Manager selection**
- **First long-term auction (3-yr product) to be conducted Feb '07**

Planned Timeline



[1] Offering Memorandum

The timing of our mitigation plan is linked to the timing of merger close

PSEG

2005/2006 Earnings Guidance

Exelon's outlook for 2005 adjusted (non-GAAP) operating earnings excludes unrealized mark-to-market adjustments from non-trading activities, income resulting from investments in synthetic fuel-producing facilities, the financial impact of the company's investment in Sithe and certain severance costs. The outlook for 2006 adjusted (non-GAAP) operating earnings is Exelon stand-alone and excludes income resulting from investments in synthetic fuel-producing facilities. These estimates do not include any impact of future changes to GAAP. Earnings guidance is based on the assumption of normal weather.

Cash Flow Definition

Exelon.

We define free cash flow as:

- Cash from operations (which includes pension contributions and the benefit of synthetic fuel investments),
- Cash used in investing activities,
- Debt issued for pension funding,
- Cash used for transition debt maturities,
- Common stock dividend payments,
- Other routine activities (e.g., severance payments, system integration costs, tax effect of discretionary items, etc.) and cash flows from divested operations

FFO Calculation and Ratios
Net Income
Add back non-cash items:
+ Depreciation, amortization (including nucl fuel amortization), AFUDC/Cap Int
+ Change in Deferred Taxes
+ Gain on Sale and Extraordinary Items
+ Trust-Preferred Interest Expense
- Transition Bond Principal Paydown

FFO

FFO Interest Coverage

FFO + Adjusted Interest

Adjusted Interest

Net Interest Expense (Before AFUDC & Cap Interest)
- Trust-Preferred Interest Expense
- Transition Bond Interest Expense
+ 10% of PV of Operating Leases

Adjusted Interest

FFO Debt Coverage

FFO

Adjusted Average Debt (1)

Debt:
LTD
STD
- Transition Bond Principal Balance

Add debt equivalents:
+ A/R Financing
+ PV of Operating Leases

Adjusted Debt
(1) Use average of prior year and current year adjusted debt balance

Debt to Total Cap

Adjusted Book Debt

Total Adjusted Capitalization

Debt:
LTD
STD
- Transition Bond Principal Balance

Adjusted Book Debt

Capitalization:
Total Shareholders’ Equity H Preferred Securities of Subsidiaries
Adjusted Book Debt

Total Adjusted Capitalization

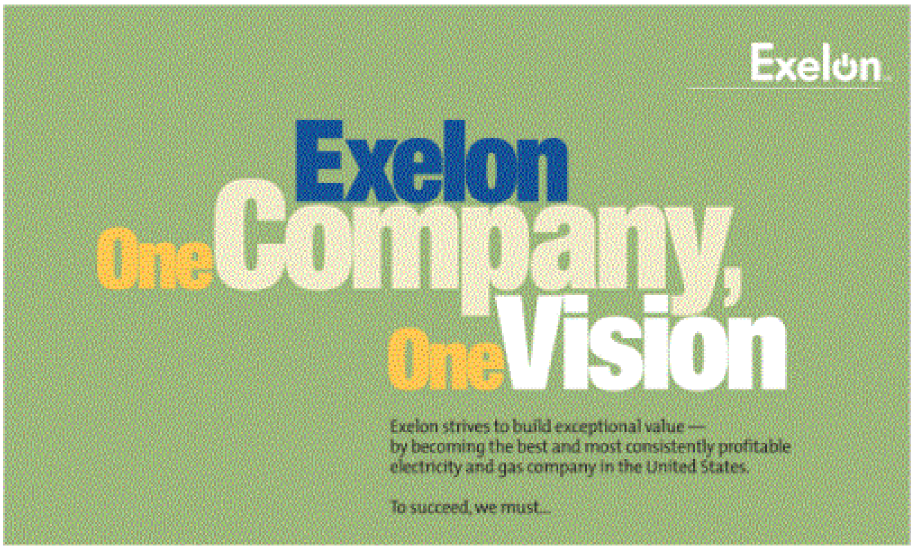
Note: FFO and Debt related to non-recourse debt are excluded from the calculations.

Wrap-up / Q&A

John Rowe
Chairman, President & Chief Executive Officer

Exelon Investor Conference
New York City
August 5, 2005

Pursuing the Vision



Live Up to our Commitments

Perform at World-Class Levels

Disciplined Financial Management

Realizing the Promise, Pursuing the Vision

Nuclear Fleet Profile

	Number of units	Net average annual rating 2004*	License expiration date	Comments
Braidwood	2	2,363	2026, 2027	
Byron	2	2,336	2024, 2026	
Clinton	1	1,030	2026	
Dresden	2	1,742	2029, 2031	License renewal approved by NRC 10/04
LaSalle	2	2,288	2022, 2023	
Limerick	2	2,309	2024, 2029	
Oyster Creek	1	625	2009	License renewal application filed 7/05 **
Peach Bottom	2	2,262	2033, 2034	License renewal approved by NRC 5/03
Quad Cities	2	1,737	2032	License renewal approved by NRC 10/04
TMI-1	1	837	2014	License renewal decision under review
Total	17	17,529		

* Shown at 100% of capacity

** A 12/04 NRC order permits Oyster Creek to operate beyond its license expiration if the NRC has not completed its renewal application review

Summary of NuStart Project

July 2005

Background

The NuStart consortium was formed for the purpose of serving as a unified industry entity to respond to a Department of Energy (DOE) solicitation to receive 50/50 cost-share funding for projects designed to address the challenges facing a new nuclear investment. The overall goal of the consortium is to preserve the nuclear option for future investment decisions by reducing the time to market for a new plant. No decision to build a new nuclear plant has been made by NuStart or any of its members at this time.

Participants in NuStart Consortium:

1. Constellation
2. Duke Energy
3. EDF International North America
4. Entergy
5. Exelon
6. Florida Power and Light
7. Progress Energy
8. Southern Company
9. Tennessee Valley Authority (TVA)
10. Westinghouse
11. General Electric

Project Objectives:

- Demonstrate new licensing process by preparing and submitting Combined Operating License (COL) applications to the Nuclear Regulatory Commission for review and approval.
- Complete the design engineering work for the selected advanced reactor technologies, the Westinghouse Advanced Passive (AP) 1000 and the General Electric Economic Simplified Boiling Water Reactor (ESBWR).

Project Milestones:

•	NuStart Formed	March 2004
•	Proposal submitted to DOE	April 2004
•	Notified by DOE as award candidate	November 2004
•	Cooperative Agreement finalized with DOE	May 2005
•	Select sites for subject of COLs	September 2005
•	Submit Design Certification application for ESBWR	September 2005
•	Receive Design Certification for AP1000	December 2005
•	Submit COL applications	2007/08
•	Receive approved COLs from NRC	2010/11

Project Funding:

- Eight of the nine power companies (excluding TVA) will be providing approximately $7M each for a total of $56M
- TVA to provide $.6M of in-kind services
- General Electric and Westinghouse will collectively provide $204M
- Total industry contribution: $260M
- DOE matching funds: $260M
- Total project cost: $520M

ComEd Restructuring Legislation

Enacted Dec. 1997

Rate Reductions

- Residential - 15% effective 1/1/98 ~ $400 million total
  5% effective 10/1/2001 ~ $100 million total

Direct Access Phase-In Schedule

- Residential
  5/1/2002 100% of residential customers have supplier choice.
- Commercial and Industrial, including Governmental

  All C&I customers had supplier choice effective 12/31/00.

Transition Cost Recovery Provisions

1) Bundled rates are frozen through 2006 (originally 2004) at 1996 levels after taking the residential rate reductions described above.

2) Unbundled delivery service rates apply to customers who choose an alternate supplier or the market rate for energy (ComEd PPO).

- Utilities recover transition costs via a Competitive Transition Charge (CTC) from customers who select an alternate supplier. The CTC will apply through 2006 for all classes. The CTC will be calculated based on the following formula:

CTC = Tariff/contract revenues *minus*
Delivery service revenue *minus*
Market value of electricity *minus*
Mitigation factor

(See current and proposed delivery rate schedules attached.)

Mitigation Factor

The mitigation factor is a credit averaging 0.5 cents/kWh offered by the utility to delivery service only customers.

- The mitigation factor for commercial and industrial customers is:

10/1/99-12/31/02	0.5 cents per kWh or 8%
2003-2004	0.5 cents per kWh or 10%
2005	0.6 cents per kWh or 11%
2006	0.9 cents per kWh or 12%

- The mitigation factor for residential customers is calculated as a percentage of base rates after the rate reductions are in effect. The applicable percentages are as follows:

2002	6% of base rates after rate reductions
2003-2004	7% of base rates after rate reductions
2005	8% of base rates after rate reductions
2006	10% of base rates after rate reductions

Transition Period Provision

During the transition period utilities will be able to reorganize, sell or assign assets; retire or remove plants from service; unbundle or restructure tariffs on a revenue neutral basis (with impact limitations described in Earnings and Viability below); and accelerate depreciation or amortization of assets without ICC approval. The ICC could intercede if it believed the transaction jeopardized reliable service.

Earnings and Viability

The maximum allowable rate of return will be pegged to the 30-year T-Bond rate, plus 8.5%. If earnings exceed the allowed rate of return by more than 1.5%, 50% of the excess earnings would be shared with customers. If the rate of return is below the T-bond Rate, the utilities can apply to the ICC for a rate increase.

Securitization

Utilities are allowed to utilize securitization of transition period revenues as a means to mitigate stranded costs. The proceeds primarily are to be used to retire debt and equity, and to repay or retire fuel obligations if the Commission finds such use is the public interest.

Amount allowable for securitization is capped by 50% of capitalization. In December 1998, ComEd securitized $3.4 billion.

ComEd ROE Cap – Earnings Sharing Formula

- Applies through the end of the transition period (Dec. 31, 2006)
- Index Calculation: 12-month simple average of "Monthly Treasury Long-Term Average Rates"

  Plus: 7% Index Adder

  Plus: 1.5% Index Margin
- ComEd's two-year average ROE must exceed the two-year average of this index for the same two years before invoking a 50% earnings sharing provision
- Only the incremental earnings contributing to the percentage in excess of the index is subject to sharing
- Goodwill is included as equity for purposes of calculating ComEd's ROE; a goodwill impairment would have no impact on the ROE rate cap during the transition period

Commonwealth Edison Company

Determination of Residential Customer Transition Charge (Class Summary Page)
Based on Market Value Defined in Rider PPO — Power Purchase Option (Market Index) Applicable Period A (June 2005 — May 2006)
(All units are in cents per kilowatt-hour)

Customer Transition Charge Customer Class	Base Rate Revenue (1)(2) (A)	Delivery Service Revenue (3) (B)	Market Value (4) (C)	2005 Mitigation Amount (5) (D)	**June 2005 - December 31, 2005 CTC** (E) = (A) - (B) - (C) - (D)	2006 Mitigation Amount (6) (F)	**January 1, 2006 - May, 2006 CTC** (G) = (A) - (B) - (C) - (F)
Residential Delivery Service Customers							
Single Family Without Space Heat	8.715	3.470	4.272	0.697	**0.276**	0.872	**0.101**
Multi Family Without Space Heat	8.961	4.546	4.411	0.717	**0.000**	0.896	**0.000**
Single Family With Space Heat	5.836	2.433	4.232	0.467	**0.000**	0.584	**0.000**
Multi Family With Space Heat	6.169	2.994	4.346	0.494	**0.000**	0.617	**0.000**
Fixture-included Lighting Residential Delivery Service Customers	8.655	10.003	3.422	0.692	**0.000**	0.866	**0.000**

Notes:

(1) Based on three years of residential historical data ending January 2002 and residential rates in effect beginning October 1, 2001.

(2) Base rate revenues consist of customer service and energy charges. Base rate revenues do not include facility, meter, or other equipment rentals, franchise fees or other franchise cost additions, fuel adjustment clause charges, decommissioning expense adjustment clause charges, taxes, local government compliance clause charges, compensation for energy generated by a person or entity other than ComEd, or Renewable Energy Resources and Coal Technology Development Assistance Charge and Energy Assistance Charge for the Supplemental Low-Income Energy Assistance Fund.

(3) The amount of revenue that the Company would receive under Rate RCDS — Retail Customer Delivery Service (Rate RCDS) and Rider TS — Transmission Services (Rider TS) for standard delivery of energy to customers in the CTC Customer Class.

(4) The Market Value for a CTC Customer Class has the same value as the per kilowatt-hour Load Weighted Average Market Value (LWAMV) as defined in Rider PPO — Power Purchase Option (Market Index) for the applicable delivery service customer class.

(5) The residential mitigation amount as defined in Rate CTC is 8% of the base rate revenue for the calendar year 2005.

(6) The residential mitigation amount as defined in Rate CTC is 10% of the base rate revenue for the calendar year 2006.

Commonwealth Edison Company

Determination of Nonresidential Customer Transition Charge (Summary Page)
Based on Market Value Defined in Rider PPO — Power Purchase Option (Market Index) Applicable Period A (June 2005 — May 2006)
(All units are in cents per kilowatt-hour)

Customer Transition Charge Customer Class	Base Rate Revenue (l)(2) (A)	Delivery Service Revenue (1)(3) (B)	Market Value (4) (C)	2005 Mitigation Amount (5) (D)	**June 2005 - December 31, 2005 CTC (6)(7)** (E) = (A)-(B)-(C)-(D)	2006 Mitigation Amount (8) (F)	**January 1, 2006 - May 2006 CTC (6, 7)** (G) = (A)-(B)-(C)-(F)
Nonresidential Delivery Service Customers							
With Only Watt-hour Only Meters	11.258	3.897	4.435	1.238	**1.688**	1.351	**1.575**
0 kW to and including 25 kW Demand	9.288	2.307	4.350	1.022	**1.609**	1.115	**1.516**
Over 25 kW to and including 100 kW Demand	8.344	2.062	4.372	0.918	**0.992**	1.001	**0.909**
Over 100 kW to and including 400 kW Demand	7.428	1.680	4.338	0.817	**0.593**	0.900	**0.510**
Fixture-included Lighting Nonresidential Delivery Service Customers	13.554	10.003	3.401	1.491	**0.000**	1.626	**0.000**
Street Lighting Delivery Service Customers — Dusk to Dawn	3.852	2.052	3.388	0.600	**0.000**	0.900	**0.000**
Street Lighting Delivery Service Customers — All Other Lighting	7.172	2.021	3.934	0.789	**0.428**	0.900	**0.317**
Railroad Delivery Service Customers (9)							
Pumping Delivery Service Customers	6.465	1.625	4.054	0.711	**0.075**	0.900	**0.000**

Notes:

(1) Transfer from Column (H) and Column (M) of Determination of Customer Transition Charge, on Pages 2 to 9 of attached work papers.

(2) Base rate revenues consist of customer, demand, and energy charges. Base rate revenues do not include facility, meter, or other equipment rentals, franchise fees or other franchise cost additions, fuel adjustment clause charges, decommissioning expense adjustment clause charges, taxes, local

government compliance clause charges, compensation for energy generated by a person or entity other than ComEd, or Renewable Energy Resources and Coal Technology Development Assistance Charge and Energy Assistance Charge for the Supplemental Low-Income Energy Assistance Fund.

(3) The amount of revenue that the Company would receive under Rate RCDS — Retail Customer Delivery Service (Rate RCDS) and Rider TS — Transmission Services (Rider TS) for standard delivery of energy to customers in the CTC Customer Class.

(4) The Market Value for a CTC Customer Class has the same value as the per kilowatt-hour Load Weighted Average Market Value (LWAMV) as defined in Rider PPO — Power Purchase Option (Market Index) for the applicable customer class for Applicable Period A.

(5) The mitigation amount as defined in Rate CTC is the greater of 0.6 cents per kilowatt-hour or 11% of the base rate revenue for the calendar year 2005.

(6) This Applicable Period A Customer Transition Charge (CTC) is not applicable if you are taking service under a multi-year CTC option under Rider CTC — MY — Customer Transition Charges — Multi-Year (Rider CTC-MY).

(7) CTCs are subject to change without specific notice if one of the components used in the determination of the CTC, as described in Rate CTC, is modified. If the CTC is equal to zero, this account will not be eligible for service under Rider PPO — Power Purchase Option (Market Index) (Rider PPO).

(8) The mitigation amount as defined in Rate CTC is the greater of 0.9 cents per kilowatt-hour or 12% of the base rate revenue for the calendar year of 2005.

(9) There are two customers in the Railroad class and each customer will have a Customer-specific CTC.

Restructuring Settlement

This summary of the major elements of the 1998 settlement reflects amendments made in 2000 following announcement of the PECO Unicom merger.

- Recovery of $5.26 billion of stranded costs over a 12-year transition period beginning January 1, 1999 and ending December 31, 2010, with a return of 10.75 percent.
- Rate caps will vary over the transition period. (See Table on Page 2.)
- On January 1, 1999 PECO unbundled rates into three components:
  - a transmission and distribution rate of 2.98 cents per kWh.
  - a competitive transition charge (CTC) designed to recover the $5.26 billion of stranded costs. Revenue collected through the CTC will be reconciled annually based on actual sales.
  - a shopping credit initially set at 4.46 cents per kWh on a system-wide basis.
- Authorization for PECO to securitize up to $5 billion of stranded costs. (PECO has securitized fully to its $5B limit.) The intangible transition charges associated with transition bonds terminate no later than December 31, 2010.
- Flexible pricing, within a specified range, for residential default customers.
- Customer choice phased in between January 1, 1999 and January 2, 2000.
- Authorization for PECO to transfer its generation assets to a separate entity.
- Ability of electric generation suppliers (EGS) to provide metering and billing services to retail customers who have direct access.
- As required by law, on January 1, 2001 the provider of default service for 20 percent of residential customers was bid competitively.
- If 35 percent and 50 percent of all customers are not shopping by 2001 and 2003, respectively, a number of customers sufficient to equal those trigger points shall be randomly selected and assigned to licensed suppliers by a PUC-determined process.
- PLR Requirement: PECO is PLR through 2010.·

Schedule of System Average Rates
¢/kWh

Effective Date	Transmission(a) (1)	Distribution (2)	T&D Rate Cap(b) (3)	CTC/ITC (4)	Credit for Delivery Service Only (5)	Generation Rate Cap(c) (6)
January 1, 2004	0.45	2.41	2.86	2.43	4.55	6.98
January 1, 2005	0.45	2.41	2.86	2.40	4.58	6.98
January 1, 2006	0.45	2.53	2.98	2.66	4.85	7.51
January 1, 2007	N/A	N/A	N/A	2.66	5.35	8.01
January 1, 2008	N/A	N/A	N/A	2.66	5.35	8.01
January 1, 2009	N/A	N/A	N/A	2.66	5.35	8.01
January 1, 2010	N/A	N/A	N/A	2.66	5.35	8.01

Note: Original settlement rates.

(a) Transmission prices listed are for illustration only. The PUC does not regulate rates for transmission Service.

(b) T&D Rate Cap (column 3) = sum of columns (1)+(2).

(c) Generation Rate Cap (column 6) = sum of columns (4)+(5).

Notes:

- Average figures for CTC/ITC from 2004-2010 in column 4 are fixed, subject to reconciliation for actual sales levels.
- The credit (paid to delivery-service-only-customers) figures in column 5 will be adjusted to reflect changes due to the CTC/ITC reconciliation.
- Average transmission and distribution service rates will not exceed the figures in column 3.
- The generation portion of bills for customers who remain with regulated PECO generation supply will not, on average, exceed figures in column 6.
- Calculation of average rates for 2004: 9.84¢/kWh = 2.86 (column 3) + 2.43 (column 4) + 4.55 (column 5)

PECO ENERGY
CTC Amortization

Annual Stranded Cost
Amortization and Return (a)

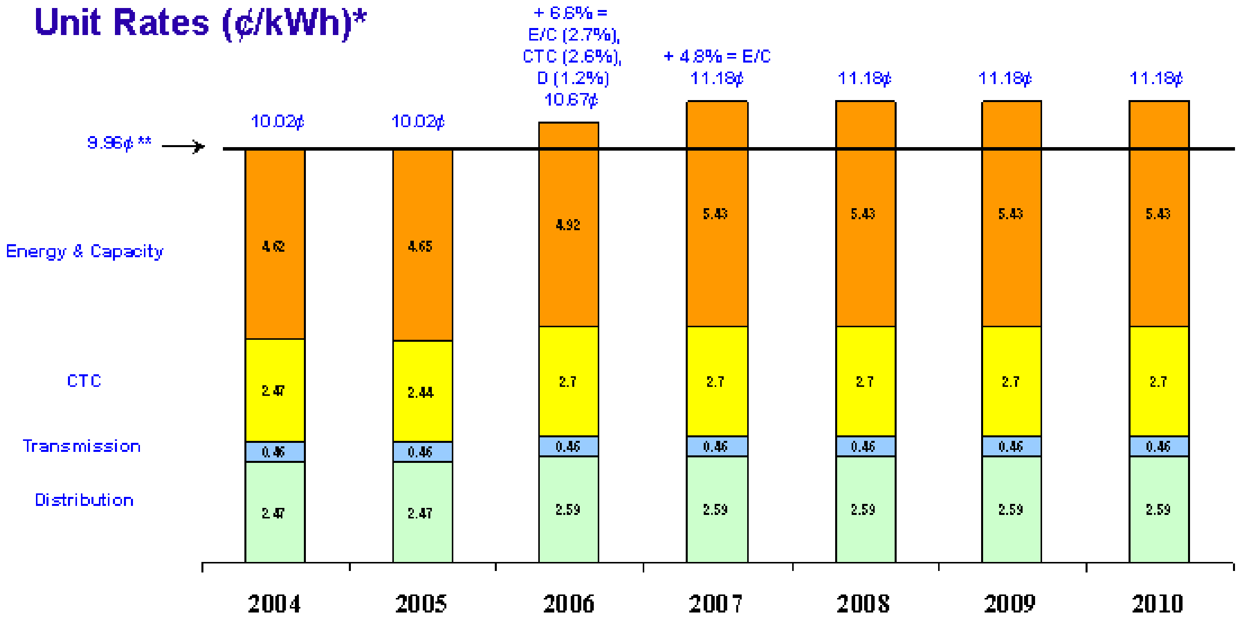
Year	Annual Sales MWh	CTC ¢/kWh	Revenue, excluding Gross Receipts Tax Total ($000)	Return @ 10.75% ($000)	Amortization ($000)
2004	34,933,789	2.43	811,540	444,798	366,742
2005	35,213,260	2.40	807,933	403,555	404,378
2006	35,494,966	2.66	902,623	353,070	549,553
2007	35,778,925	2.66	909,844	290,627	619,217
2008	36,065,157	2.66	917,123	220,312	696,811
2009	36,353,678	2.66	924,459	141,229	783,231
2010	36,644,507	2.66	931,855	52,381	879,474

(a) Subject to reconciliation of actual sales and collections. Under the settlement, sales are estimated to increase 0.8 percent per year.

Other Features

- The transmission & distribution rate cap of 2.98 cents per kWh includes .01 cent for a sustainable energy and economic development fund during the rate cap period.
- PECO is permitted to transfer ownership and operation of its generating facilities to a separate corporate entity. The generating facilities will be valued at book value at the time of the transfer.
- Market share thresholds were established as of January 1, 2001 to promote competition. The PLR would be selected on the basis of a PUC-approved energy and capacity market price bidding process. PECO-affiliated suppliers would be prohibited from bidding for this block of customers.
- As of January 1, 2001, PECO (as PLR) will price its service to residential customers within a specified range.
- A Qualified Rate Order authorizing securitization of up to $4 billion is included (subsequently increased to $5 billion).

PECO Electric Restructuring & Merger Settlements



* Rates increased from original settlement by 1.6% to reflect the roll-in of increased Gross Receipts Tax and $0.02/kWh for Universal Service Fund Charge and Nuclear Decommissioning Cost Adjustment.

** Original settlement total rate cap based on rates at 1/1/97.

July 2005

PECO Bundled Rates

PECO's bundled rates (which include charges for transmission & distribution, stranded cost recovery and a capacity and energy charge, or shopping credit) were capped through 2010. The bundled rate is scheduled to increase in 2006 and 2007 with the following estimated impact on Exelon's cash and EPS:

Year	T&D Rate Cap	Generation Rate Cap	Bundled Rate	Revenue	Stranded Cost Amortization*	Net Income Impact	EPS Impact	Cash Impact**
	(cents/kWh)			Incremental Impact ($ in millions)				
2005E	2.93	7.09	10.02	-	-	-	-	-
2006E	3.05	7.62	10.67	240	150	60	$0.09	160
2007E	3.05	8.13	11.18	190	70	80	$0.12	130

Notes: Estimates based on Exelon forecasted energy sales; approximate 35% effective income tax rate assumption.
Rates shown here reflect latest annual reconciliations from original settlement for Gross Receipts Tax, Universal Service Fund Charge and Nuclear Decommissioning Cost Adjustments; these reconciliations have no material net income or cash impact.
* Per table on page 104 of 2004 Form 10-K filing
** Cash impact before principal payments on securitization debt

July 2005

Securities Ratings for Exelon and its Subsidiary Companies

	Securities	Standard & Poor's [1]	Moody's Investors Service	Fitch
Exelon	Senior unsecured debt	BBB+	Baa2	BBB+
	Commercial paper	A2	P2	F2
ComEd	Senior secured debt	A-	A3	A-
	Commercial paper	A2	P2	F2
PECO	Senior secured debt	A-	A2	A
	Commercial paper	A2	P1	F1
Generation	Senior unsecured debt	A-	Baa1	BBB+
	Commercial paper	A2	P2	F2

[1] On December 20, 2004, Standard and Poor's placed the ratings of Exelon and its subsidiaries on credit watch with negative implications in response to the announced merger between Exelon & PSEG.

August 1, 2005

Exelon Corporation

Transitional Bond Summary

($ in millions)	Dec-00	Dec-01	Dec-02	Dec-03	Dec-04	Dec-05	Dec-06	Dec-07	Dec-08	Dec-09	Dec-10
ComEd											
Year End Principal Balance	$2,720	$2,380	$2,040	$1,700	$1,360	$1,020	$ 680	$ 340	$ —	$ —	$ —
Principal Payments		$ 340	$ 340	$ 340	$ 340	$ 340	$ 340	$ 340	$ 340	$ —	$ —
PECO											
Year End Principal Balance	$4,838	$4,582	$4,255	$4,015	$3,725	$3,295	$2,775	$2,135	$1,505	$805	$ —
Principal Payments		$ 256	$ 327	$ 240	$ 290	$ 430	$ 520	$ 640	$ 630	$700	$805
Total											
Year End Principal Balance	$7,558	$6,962	$6,295	$5,715	$5,085	$4,315	$3,455	$2,475	$1,505	$805	$ —
Principal Payments		$ 596	$ 667	$ 580	$ 630	$ 770	$ 860	$ 980	$ 970	$700	$805

Exelon

August 2005

Exelon Corporation (Holding Co.)
Long-Term Debt Outstanding By Issue
As of June 30, 2005

Series	Interest Rate	Date Issued	Maturity Date	Debt Outstanding	Current Portion	Long-Term Debt
Senior Notes — Exelon Corporation						
2005 Senior Notes	4.45%	06/09/05	06/15/10	$ 400,000,000	$0	$ 400,000,000
2005 Senior Notes	4.90%	06/09/05	06/15/15	$ 800,000,000	$0	$ 800,000,000
2005 Senior Notes	5.625%	06/09/05	06/15/35	$ 500,000,000	$0	$ 500,000,000
2001 Senior Notes	6.75%	05/08/01	05/01/11	$ 500,000,000	$0	$ 500,000,000
Total Senior Notes — Exelon Corporation				$2,200,000,000	$0	$2,200,000,000
Total Exelon Corporation Long-Term Debt				$**2,200,000,000**	$0	$2,200,000,000

ComEd
Long-Term Debt Outstanding By Issue
As of June 30, 2005

Series	Interest Rate	Date Issued	Maturity Date	Debt Outstanding	Current Portion	Long-Term Debt
First Mortgage Bonds						
93	7.000%	07/01/93	07/01/05	$ 162,910,000	$162,910,000	$ 0
76	8.250%	10/01/91	10/01/06	95,000,000	0	95,000,000
78	8.375%	10/15/91	10/15/06	31,021,000	0	31,021,000
Pollution Control-1996A	4.400%	06/27/96	12/01/06	110,000,000	0	110,000,000
Pollution Control-1996B	4.400%	06/27/96	12/01/06	89,400,000	0	89,400,000
99	3.700%	01/22/03	02/01/08	295,000,000	0	295,000,000
83	8.000%	05/15/92	05/15/08	120,000,000	0	120,000,000
Pollution Control-1994B	5.700%	01/15/94	01/15/09	15,900,000	0	15,900,000
102	4.740%	08/25/03	08/15/10	212,000,000	0	212,000,000
98	6.150%	03/13/02	03/15/12	450,000,000	0	450,000,000
92	7.625%	04/15/93	04/15/13	125,000,000	0	125,000,000
IL Dev. Fin. Authority - 2002 A	Variable	06/04/02	04/15/13	100,000,000	0	100,000,000
94	7.500%	07/01/93	07/01/13	127,000,000	0	127,000,000
IL Dev. Fin. Authority - 2003 D	Variable	12/23/03	01/15/14	19,975,000	0	19,975,000
Pollution Control-1994C	5.850%	01/15/94	01/15/14	17,000,000	0	17,000,000
IL Fin. Authority - 2005	Variable	03/17/05	03/01/17	91,000,000	0	91,000,000
101	4.700%	04/07/03	04/15/15	260,000,000	0	260,000,000
IL Dev. Fin. Authority - 2003 A	Variable	05/08/03	05/15/17	40,000,000	0	40,000,000
IL Dev. Fin. Authority - 2003 B	Variable	09/24/03	11/01/19	42,200,000	0	42,200,000
IL Dev. Fin. Authority - 2003 C	Variable	11/19/03	03/01/20	50,000,000	0	50,000,000
100	5.875%	01/22/03	02/01/33	253,600,000	0	253,600,000
Total First Mortgage Bonds				$2,707,006,000	$162,910,000	$2,544,096,000
Sinking Fund Debentures						
Sinking Fund Debenture	3.875%	01/01/58	01/01/08	4,000,000	1,000,000	3,000,000
Sinking Fund Debenture	4.625%	01/01/59	01/01/09	2,000,000	400,000	1,600,000
Sinking Fund Debenture	4.750%	12/01/61	12/01/11	5,600,000	800,000	4,800,000
Total Sinking Fund Debentures				$ 11,600,000	$ 2,200,000	$ 9,400,000
Notes Payable						
Notes	6.400%	10/15/93	10/15/05	107,024,000	107,024,000	0
Notes	7.625%	01/09/97	01/15/07	145,000,000	0	145,000,000
Notes	6.950%	07/16/98	07/15/18	140,000,000	0	140,000,000
Total Notes Payable				392,024,000	107,024,000	285,000,000
Total Long-Term Debt				**$3,110,630,000**		
Long-Term Debt to Financing Trusts						
Class A-6 Transitional Funding Trust Notes, Series 1998	5.630%	12/16/98	06/25/07	639,998,590	299,998,590	340,000,000
Class A-7 Transitional Funding Trust Notes, Series 1998	5.740%	12/16/98	12/25/08	510,000,000	0	510,000,000
Subordinated Debentures	6.350%	03/17/03	03/15/33	206,186,000	0	206,186,000
Subordinated Debentures	8.500%	01/24/97	01/15/27	154,640,000	0	154,640,000
Total Long-Term Debt to Financing Trusts				**$1,510,824,590**	$299,998,590	$1,210,826,000

PECO Energy
Long-Term Debt Outstanding By Issue
As of June 30, 2005

Series	Interest Rate	Issue Date	Maturity Date	Debt Outstanding	Current Portion	Long-Term Debt
First and Refunding Mortgage Bonds						
FMB	5.90%	04/23/04	05/01/34	$ 75,000,000	$ 0	$ 75,000,000
FMB	3.50%	04/28/03	05/01/08	450,000,000	0	450,000,000
FMB	5.95%	11/01/01	11/01/11	250,000,000	0	250,000,000
FMB	4.75%	9/23/02	10/1/12	225,000,000	0	225,000,000
Total First Mortgage Bonds				$1,000,000,000	$ 0	$1,000,000,000
Mortgage—Backed Pollution Control Notes						
Delaware Co. 1988 Ser. A	var. rate	04/01/93	12/01/12	50,000,000	0	50,000,000
Delaware Co. 1988 Ser. B	var. rate	04/01/93	12/01/12	50,000,000	0	50,000,000
Delaware Co. 1988 Ser. C	var. rate	04/01/93	12/01/12	50,000,000	0	50,000,000
Salem Co. 1988 Ser. A	var. rate	04/01/93	12/01/12	4,200,000	0	4,200,000
Total Mortgage-Backed Pollution Control Notes				$ 154,200,000	$ 0	$ 154,200,000
Notes Payable — Accts. Rec. Agreement	variable		11/14/05	37,586,111	37,586,111	0
Total Long-Term Debt				$ **1,191,786,111**		
Long-Term Debt to PETT* and Other Financing Trusts						
1999 A-6	6.0500%	03/26/99	03/01/07	796,791,475	210,805,100	585,986,375
1999 A-7	6.1300%	03/26/99	09/01/08	896,653,425	0	896,653,425
2000 A-3	7.6250%	05/02/00	03/01/09	398,838,452	0	398,838,452
2000 A-4	7.6500%	05/02/00	09/01/09	351,161,548	0	351,161,548
2001 A-1	6.5200%	03/01/01	09/01/10	805,460,000	0	805,460,000
PECO Energy Capital Trust III Series D	7.38%	04/06/98	04/06/28	81,325,825	0	81,325,825
PECO Energy Capital Trust IV	5.75%	06/24/03	06/15/33	103,092,784	0	103,092,784
Total Long-Term Debt to PETT and Other Financing Trusts				$**3,433,323,509**	$210,805,100	$3,222,518,409

* PETT — PECO Energy Transition Trust

Exelon Generation

Long-Term Debt Outstanding By Issue
As of June 30, 2005

Series	Interest Rate	Issue Date	Maturity Date	Debt Outstanding	Current Portion	Long-Term Debt
Senior Notes						
2001 Senior Unsecured Notes	6.95%	6/14/01	6/15/11	$ 700,000,000	$ 0	$ 700,000,000
2003 Senior Unsecured Notes	5.35%	12/16/03	1/15/14	500,000,000	0	500,000,000
Total Senior Unsecured Notes				$ 1,200,000,000	$ 0	$ 1,200,000,000
Unsecured Pollution Control Notes						
Montgomery Co. 2001 Ser. B	var. rate	9/5/01	10/1/30	68,795,000	0	68,795,000
Delaware Co. 2001 Ser. A	var. rate	4/25/01	4/1/21	39,235,000	0	39,235,000
Montgomery Co. 2001 Ser. A	var. rate	4/25/01	10/1/34	13,150,000	0	13,150,000
Delaware Co. 1993 Ser. A	var. rate	8/24/93	8/1/16	24,125,000	0	24,125,000
Salem Co. 1993 Ser. A	var. rate	9/9/93	3/1/25	23,000,000	0	23,000,000
Montgomery Co. 1994 Ser. A	var. rate	2/14/95	6/1/29	82,560,000	0	82,560,000
Montgomery Co. 1994 Ser. B	var. rate	7/2/95	6/1/29	13,340,000	0	13,340,000
York County 1993 Ser. A	var. rate	8/24/93	8/1/16	18,440,000	0	18,440,000
Montgomery Co. 1996 Ser. A	var. rate	3/27/96	3/1/34	34,000,000	0	34,000,000
Montgomery Co. 2002 Ser. A	var. rate	7/24/02	12/1/29	29,530,000	0	29,530,000
Indiana Co. 2003 A	var. rate	6/3/03	6/1/27	17,240,000	0	17,240,000
Delaware Co. 1999 Ser. A	var. rate	10/01/04	04/01/21	50,765,000	0	50,765,000
Montgomery Co. 1999 Ser. A	var. rate	10/01/04	10/01/30	91,775,000	0	91,775,000
Montgomery Co. 1999 Ser. B	var. rate	10/01/04	10/01/34	13,880,000	0	13,880,000
Total Unsecured Pollution Control Notes				$ 519,835,000	$ 0	$ 519,835,000
Notes Payable and Other						
Notes Payable	6.33%		8/8/09	49,304,753	9,860,951	39,443,803
Capital Lease Obligations				46,581,169	2,114,924	44,466,245
Total Notes Payable and Other				$ 95,885,922	$ 11,975,875	$ 83,910,048
Total Exelon Generation Long-Term Debt				**$ 1,815,720,922**	$ 11,975,875	$ 1,803,745,048

Exhibit 99.2

NEWS RELEASE

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FOR IMMEDIATE RELEASE

Exelon Raises 2005 Earnings Guidance, Provides Guidance for 2006

CHICAGO (Aug. 5, 2005) Exelon today raised its guidance for 2005 GAAP earnings per share to a range of $3.05 to $3.20 and its guidance for 2005 adjusted (non-GAAP) operating earnings per share to a range of $3.00 to $3.15. The company also provided guidance for 2006 adjusted (non-GAAP) operating earnings per share of between $3.00 and $3.30 (on a stand-alone basis) during a conference with analysts and investors today. The company's earnings guidance is based on the assumption of normal weather in the second half of 2005 and the full year of 2006. These estimates do not include any impact of future changes to GAAP.

Positive drivers of earnings growth in 2005 and 2006 include higher generation margins and load growth at ComEd and PECO.

"Since its inception, Exelon has provided one of the best total returns in our industry. The last twelve months have been no exception," said John W. Rowe, Exelon's chairman, president and CEO.

"Our success is attributable to many things, including dramatic improvements in our nuclear and other operations, and rigorous financial discipline," said Rowe. "But in a very real sense, our success is competition's success. Over the past five years, we have worked tirelessly to promote wholesale competition and to implement the mandate of our state policymakers. The evidence is increasingly clear that our shareholders, our customers and our employees are all benefiting as a consequence. And we believe that our impending merger with PSEG will continue that process."

Adjusted (non-GAAP) operating earnings, which generally exclude significant one-time charges or credits that are not normally associated with ongoing operations and unrealized mark-to-market adjustments from non-trading activities, are provided as a supplement to results reported in accordance with GAAP. Management uses such adjusted (non-GAAP) operating earnings measures internally to evaluate the company's performance and manage its operations. Exelon's outlook for 2005 adjusted (non-GAAP) operating earnings excludes unrealized mark-to-market adjustments from non-trading activities, income resulting from investments in synthetic fuel-producing facilities,

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the financial impact of the company's investment in Sithe and certain severance costs. The outlook for 2006 adjusted (non-GAAP) operating earnings excludes unrealized mark-to-market adjustments from non-trading activities and income resulting from investments in synthetic fuel-producing facilities. Earnings guidance is based on the assumption of normal weather.

A webcast of Exelon's Aug. 5 investor conference will be archived and available on the Investor Relations section of Exelon's Web site at www.exeloncorp.com.

This news release 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 Corporation's 2004 Annual Report on Form 10-K in (a) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations-Business Outlook and the Challenges in Managing the Business for each of Exelon, ComEd, PECO and Generation and (b) ITEM 8. Financial Statements and Supplementary Data: Exelon-Note 20, ComEd-Note 15, PECO-Note 14 and Generation-Note 16 and (2) Exelon's Current Report on Form 8-K filed on May 13, 2005 in (a) Exhibit 99.2 Management's Discussion and Analysis of Financial Condition and Results of Operations — Exelon — Business Outlook and the Challenges in Managing the Business and (b) Exhibit 99.3 Financial Statements and Supplementary Data — Exelon Corporation 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). A discussion of risks associated with the proposed merger of Exelon and Public Service Enterprise Group, Incorporated (PSEG) is included in the joint proxy statement/prospectus that Exelon filed with the SEC pursuant to Rule 424(b)(3) on June 3, 2005 (Registration No. 333-122704). Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this news release. 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 news release.

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Exelon Corporation is one of the nation's largest electric utilities with approximately 5.2 million customers and more than $14 billion in annual revenues. The company has one of the industry's largest portfolios of electricity generation capacity, with a nationwide reach and strong positions in the Midwest and Mid-Atlantic. Exelon distributes electricity to approximately 5.2 million customers in northern Illinois and Pennsylvania and gas to more than 460,000 customers in the Philadelphia area. Exelon is headquartered in Chicago and trades on the NYSE under the ticker EXC.