
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 19, 2004
(Date of earliest
event reported)

Commission File Number	Name of Registrant; 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

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Item 9. Regulation FD Disclosure

On August 19, 2004, Exelon Corporation (Exelon) will hold an investor conference in New York City. Attached as exhibits to this Current Report on Form 8-K are a news release regarding the conference and the slides and handouts to be used at the meeting.

Exhibit Index

Exhibit No.	Description
99.1	News release
99.2	Slides and handouts

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 filed by such registrant on its own behalf. No registrant makes any representation as to information relating to any other registrant.

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' 2003 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' 2003 Annual Report on Form 10-K — ITEM 8. Financial Statements and Supplementary Data: Exelon — Note 19, ComEd — Note 15, PECO — Note 14 and Generation — Note 13 and (c) other factors discussed in filings with the United States Securities and Exchange Commission (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.

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/ Robert S. Shapard

Robert S. Shapard
Executive Vice President and
Chief Financial Officer
Exelon Corporation

August 19, 2004

Exhibit 99.1

News Release

From: Exelon Corporation
Corporate Communications
P.O. Box 805379
Chicago, IL 60680-5379

Contact: Jennifer Medley, Media Relations
312.394.7189
Michael Metzner, Investor Relations
312.394.7696

FOR IMMEDIATE RELEASE

Exelon Raises 2004 Earnings Guidance, Provides Guidance for 2005

CHICAGO (Aug. 19, 2004) — Exelon today raised its guidance for 2004 adjusted (non-GAAP) operating earnings per share to a range of $2.75 to $2.90. The company also provided guidance of between $2.85 and $3.05 for 2005 adjusted (non-GAAP) operating earnings per share 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 2004 and the full year of 2005.

Drivers of earnings growth in 2005 and beyond include continued savings from The Exelon Way, higher wholesale prices, load growth and lower interest expense.

Chief Financial Officer Bob Shapard said Exelon is also on track to meet its free cash flow goal and its Exelon Way cost savings targets for the year. The Exelon Way is the company's broad initiative to improve cash flow by $300 - $600 million annually by focusing on operational excellence, simplifying procedures and standardizing processes.

"Since its inception, Exelon has provided its shareholders with one of the best total returns in our industry. Moreover, we still have room to grow, both in share price and in dividend," said John W. Rowe, Exelon's chairman and chief executive officer.

Exelon expects to generate $3.7 billion of cash from 2004 through 2006 after funding capital expenditures and its current level of dividends. According to Shapard, roughly $2.7 billion of this cash will be used to retire debt, including $1.2 billion of ComEd debt retirements this year. More than $1 billion in cash will remain available for other uses such as increased dividends and stock buybacks. Exelon recently announced it will target a dividend payout of 50 to 60 percent of ongoing earnings beginning in 2005. The intended dividend payout rate depends on Exelon achieving its objectives, including planned cash flow and balance sheet strengthening, which Shapard said Exelon is well on its way to achieve. The Board of Directors must approve the dividends each quarter after review of Exelon's circumstances at the time.

Exelon also provided an update on Illinois' transition to a fully competitive electricity market at the end of 2006. Retail rates were cut by 20 percent in 1997 and have since been frozen. ComEd, along with other marketplace participants, is participating in a series of workshops hosted by the Illinois Commerce Commission (ICC) to resolve outstanding issues associated with the end of the transition period. Workshops will be completed in September, with an ICC report to the Illinois General Assembly planned for this fall.

A Web cast of the investor conference will be archived and available on the Investor Relations section of Exelon's Web site (www.exeloncorp.com).

Adjusted (non-GAAP) operating earnings for 2004 and 2005 excludes income resulting from investments in synthetic fuel-producing facilities, the cumulative effect of adopting FIN 46-R, The Exelon Way severance, costs for accelerating the liability management program and any profit or loss related to Boston Generating. These estimates do not include any impact of future changes to GAAP.

Certain of the matters discussed in this news release 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 discussed herein as well as those discussed in Exelon Corporation's 2003 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 Our Business for Exelon, ComEd, PECO and Generation and (b) ITEM 8. Financial Statements and Supplementary Data: Exelon-Note 19, ComEd-Note 15, PECO-Note 14 and Generation-Note 13, and (c) 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 (Registrants). Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this press release. 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 press release.

Exelon Corporation is one of the nation's largest electric utilities with approximately 5 million customers and $15 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 million customers in Illinois and Pennsylvania and gas to approximately 460,000 customers in the Philadelphia area. Exelon is headquartered in Chicago and trades on the NYSE under the ticker EXC.

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Exhibit 99.2

Exelon

Forward-Looking Statements

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by a registrant include those factors discussed herein, as well as the items discussed in (a) the Registrants' 2003 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' 2003 Annual Report on Form 10-K—ITEM 8. Financial Statements and Supplementary Data: Exelon—Note 19, ComEd—Note 15, PECO—Note 14 and Generation—Note 13, and (c) other factors discussed in filings with the United States Securities and Exchange Commission (SEC) by Exelon Corporation, Commonwealth Edison Company, PECO Energy Company and Exelon Generation Company, LLC (Registrants). Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this presentation. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

Exelon

Leading The Way

John Rowe
Chairman & Chief Executive Officer

Exelon Investor Conference
New York City
August 19, 2004

Today's Agenda

Leading The Way

8:00 a.m.–8:30 a.m.	John Rowe – Introduction and Federal Regulatory Overview
8:30 a.m.–9:15 a.m.	Oliver Kingsley, Jack Skolds, Chris Crane – Leading Operations
9:15 a.m.–9:45 a.m.	Ian McLean, Ken Cornew – Power Marketing Update
9:45 a.m.–10:00 a.m.	Break
10:00 a.m.–10:30 a.m.	John Young – Generation: Strategic Overview and Economic Drivers
10:30 a.m.–11:00 a.m.	Anne Pramaggiore, Ken Cornew – IL Update and POLR Pricing
11:00 a.m.–11:30 a.m.	Robert Shapard – Financial Overview
11:30 a.m.–12:00 p.m.	John Rowe – Strategic Overview/Q&A

Exelon

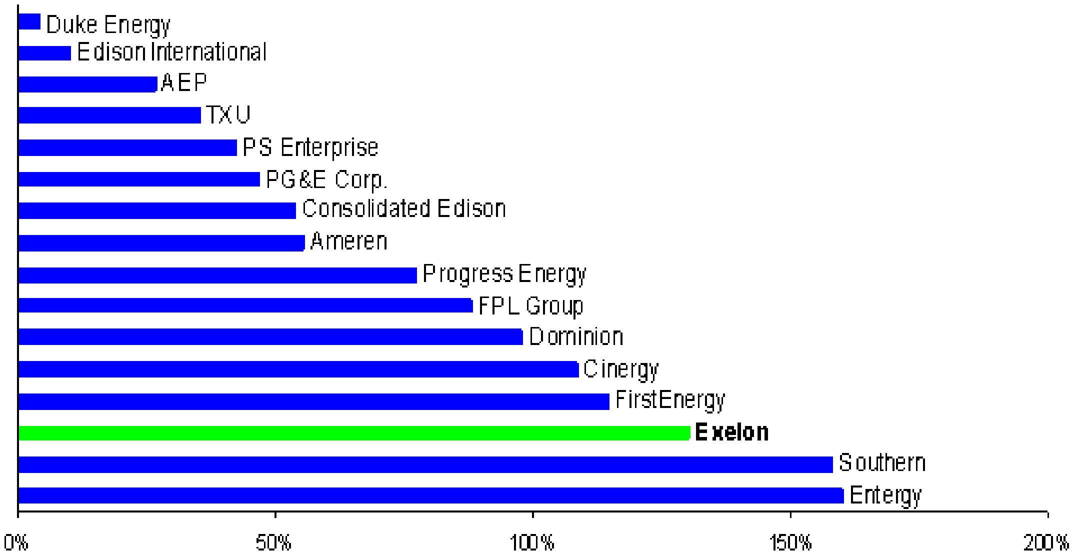
	2003	US Electric Companies
US Retail Electric Customers	5.1 Million	1st
Nuclear Capacity	17,000 MWs	1st
US Capacity Resources	37,800 MWs*	4th
Revenues	$15.8 Billion	2nd
Market Cap (as of 8/6/04)	$23.8 Billion	1st

* Operating capacity at 12/31/03; includes long-term contracts and excludes Sithe and New England assets

Sources: Company reports, Thomson Financial, Bloomberg

Total Return Comparisons

1/1/00 – 7/31/04



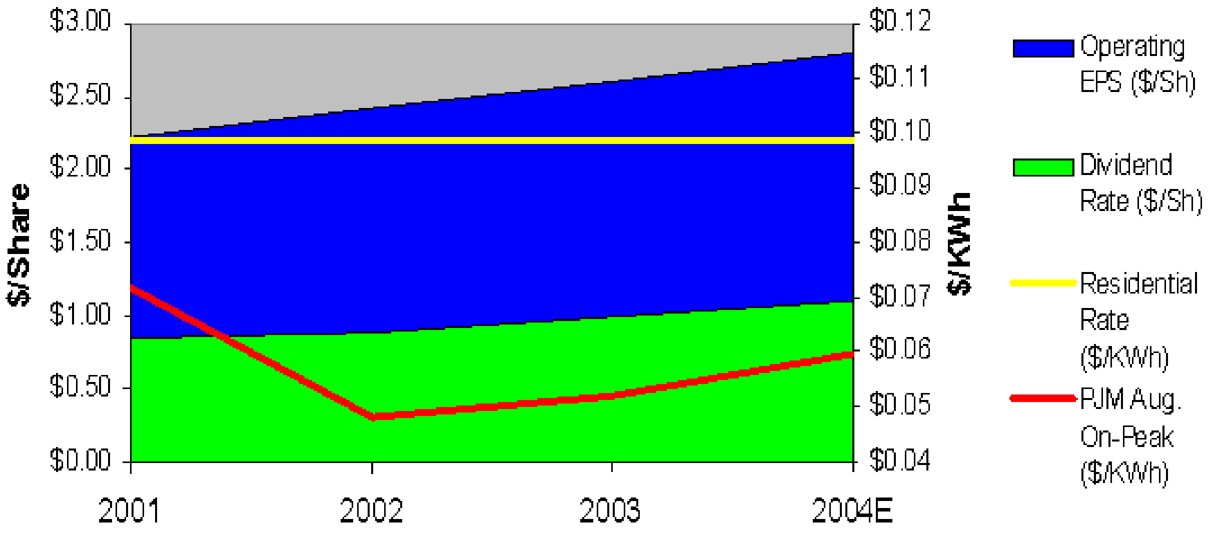
Source: Bloomberg

Peer Comparisons

	2000-2003 CAGR		2003 EBITDA		2005E
	EPS (%)	Div. (%)	Int. Cov. (X)	Yield (%)	P/E (X)
Exelon	**10.6**	**24.3**	**7.2***	**3.4**	**12.3**
AEP	-7.8	-11.7	4.6*	4.4	13.4
Ameren	-4.0	0	5.7	5.6	14.8
Cinergy	0.3	0.7	4.4	4.8	13.5
Consolidated Ed.	-3.4	0.9	4.5	5.6	14.8
Dominion Res.	10.6	0	4.0	4.1	12.2
Duke Energy	-15.9	-20.6	3.3	5.0	17.2
Edison Int.	20.4	Elim. div.**	2.3	3.0	13.5
Entergy	10.6	9.5	4.9	3.1	12.5
FirstEnergy	-11.6	0	3.7*	3.8	13.4
FPL Group	3.7	3.6	7.0	4.0	13.0
PG&E Corp.	-15.7	Elim. div.	3.3	0	12.7
Progress Energy	-2.3	2.8	4.0	5.4	11.6
PS Enterprise	1.6	0	3.7*	5.4	11.6
Southern	-2.6	1.2	6.0	4.8	14.5
TXU	-16.4	-40.7	3.0*	1.3	10.0
Average (Excl EXC)	**-2.2**	**-4.2**	**4.3**	**4.0**	**13.2**

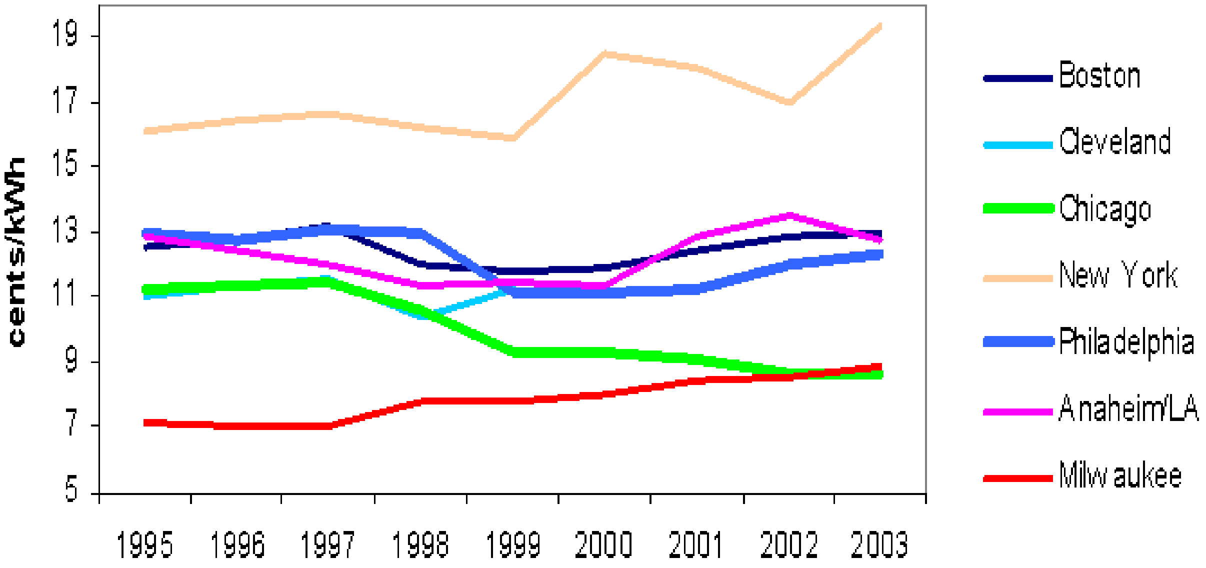
Sources: Thomson Financial, Bloomberg   Market data as of 8/6/04   CAGR = Compound annual growth rate
*Exelon estimates: excludes transition debt interest, EXC coverage ratio also excludes Boston Generating Facility debt
** Edison International reinstated dividend 1/04.   Note: See presentation appendix for reconciliation to Exelon GAAP EPS.

Steady Growth Despite Volatile Markets – Without Rate Increases



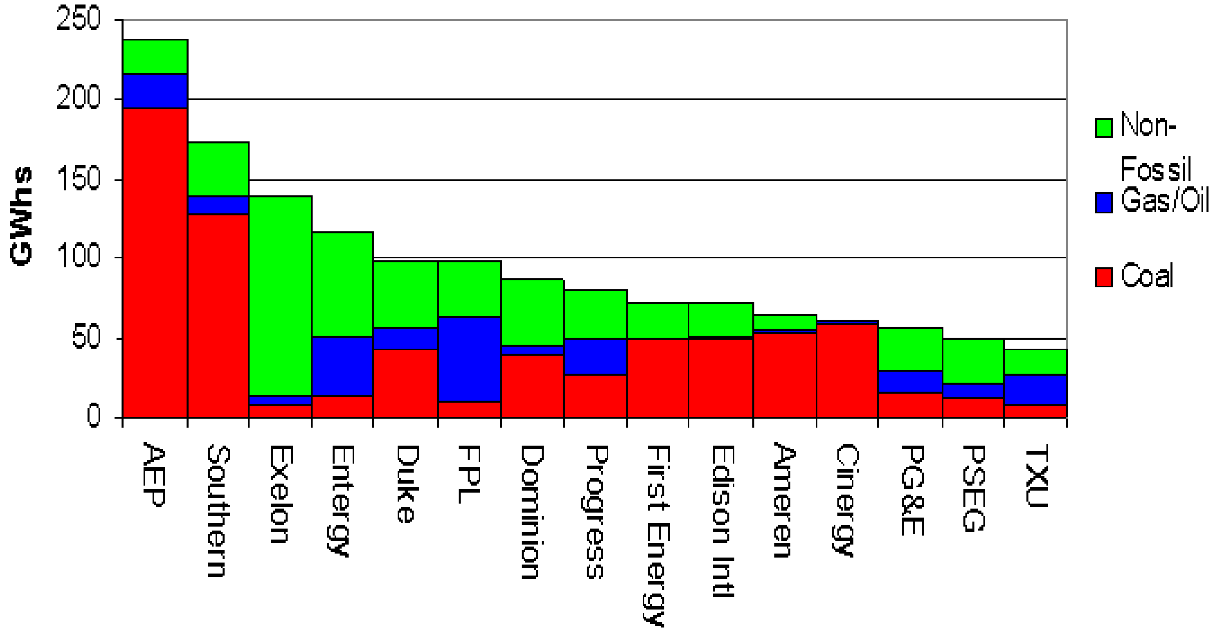
Note: See presentation appendix for reconciliation of adjusted (non-GAAP) operating EPS to GAAP EPS.

Metropolitan Residential Electric Rates



Source: EEI Typical Bill and Average Rate report – Winter 2004 (2003 data)

An Environmental Asset



2002 Generation by Fuel Source

Appendix:

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

2000 GAAP Reported EPS	**$**	**1.44**
Change in common shares		(0.53)
Extraordinary items		(0.04)
Cumulative effect of accounting change		—
Unicom pre-merger results		0.79
Merger-related costs		0.34
Pro forma merger accounting adjustments		(0.07)
2000 Adjusted (non-GAAP) Operating EPS	**$**	**1.93**
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**

Note: EPS figures reflect 2-for-1 stock split effective 5/5/04. Three-year 2003/2000 compound annual growth rate (CAGR): $1.38/$1.44 = - -1.4% based on GAAP reported results. Three-year 2003/2000 CAGR: $2.61/$1.93 = 10.6% based on adjusted (non-GAAP) operating results.

Appendix:

Stock Ownership—John W. Rowe

As of August 16, 2004:

Stock ownership goal under Exelon’s stock ownership requirement: 229,446

Shares owned by Mr. Rowe (including deferred shares and shares held by his spouse): 387,780

Stock options held by Mr. Rowe:

Vested: 1,997,239

Unvested: 795,833

Note: Mr. Rowe has a 10b5-1 plan to exercise and sell before the end of February 2005 the remaining 171,872 options under the original option grant he received when he became Chairman and CEO of Unicom in March 1998.

Leading Operations

Oliver D. Kingsley, Jr., President &
Chief Operating Officer

John L. Skolds, President, Exelon Energy Delivery

Christopher M. Crane, President, Exelon Nuclear

Exelon Investor Conference
New York City
August 19, 2004

Foundation for Leading Operations

- A defined management model that drives sustainable performance in
  - Operational excellence
  - Productivity improvement
  - Cost management
- Depth of talent and experience
  - Structured leadership development and recruiting
  - A bench capable of meeting current and future challenges
- Rigorous performance management
  - Target top quartile performance
  - Strong track record of delivering on commitments

Exelon's management model is the basis for operational discipline, sustainable performance, and the ability to replicate success.

Exelon Way Driving Improvement

- IT operational improvements, consolidation, and control
- Supplier consolidation, enhanced competition, renegotiated contracts
- Outsourcing of non-core functions
- Organization alignment and consolidation; centrally managed functional support
- More than 1500 full-time employees eliminated since Exelon Way began; 200-300 additional reductions expected by year-end

Process improvements driven by Exelon Way support sustainability of financial results.

Energy Delivery – Building the Foundation

Energy Delivery Management Model

- **Comprehensive framework for consistent execution of all we do**
  - Provides alignment around our vision, beliefs, strategic focus areas, and key business elements
  - Drives real performance improvement via an actionable business planning process
- **Playbook for driving standardization**
  - Defines the "One way, best way" to run the business
  - Aligns different parts of the business and minimizes inefficiencies
- **Performance assessment and continuous improvement tool**
  - Establishes processes for continuous assessment and improvement
  - Measures performance in an objective, meaningful manner

Management Model will be complete in 2004.

Building the Foundation

Energy Delivery Management Team – recent changes include a mix of proven leaders from across Exelon

- John Costello, Sr. VP Technical Services – former Sr. VP of Customer and Marketing Services, leading new Technical Services organization
- Doyle Beneby, reporting to John Costello as VP of Engineering and System Performance – former General Manager, Peaking Division of Exelon Power
- Ruth Ann Gillis, Sr. VP Exelon and Executive VP ComEd – former Sr. VP Exelon and President Exelon Business Services Company, leading ComEd
- Bridget Reidy, Sr. VP Customer and Marketing Services – former Sr. VP Exelon Business Services Company and Chief Supply Officer, leading Customer and Marketing Services
- Preston Swafford, Sr. VP Operations – former Nuclear Operations VP, leading core electric/gas operations and maintenance group

A team of proven leaders with successful track records is in place.

Building the Foundation

Focusing on the Fundamentals

- Productivity Improvement
  - Changes to field work planning and scheduling “Cycle Plan”, in order to improve productivity by 10-15%
- Cost Management
  - Application of new distribution capacity planning tools - $30M in reduced capital construction for 2005
  - New processes for project engineering and construction scheduling – 15-25% reduction in cost for many 2005 projects
  - Numerous other initiatives under The Exelon Way
- Operational Excellence
  - 32% fewer human performance errors over same period last year

Sustainable improvements in the fundamentals demonstrate our ability to apply the Exelon Way to Energy Delivery.

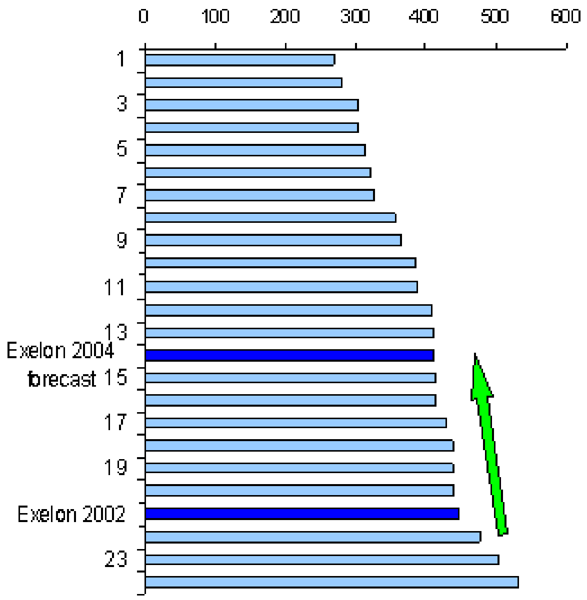
System Reliability

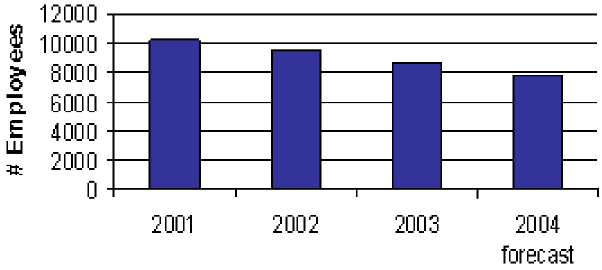
- **2003 Northeast Blackout – completed transmission operations self-assessment**
  - Immediate corrective actions completed June 1
  - Longer term plan for operational enhancements

- **Material Condition Improvement Plan – underway**
  - External, independent assessment completed
  - Stringent review of power plant and transmission switchyard maintenance underway
  - Maintenance task backlogs targeted for reduction

"Keeping the lights on" is paramount.

Cost Reduction


Benchmarking - $/customer

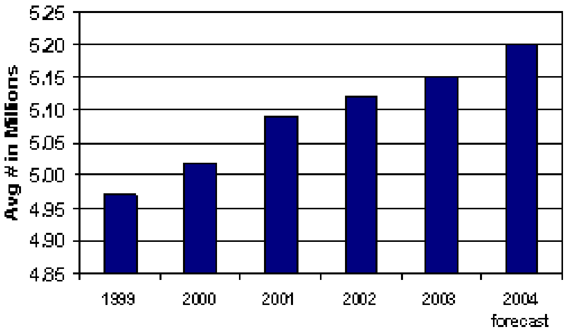

Energy Delivery Employees

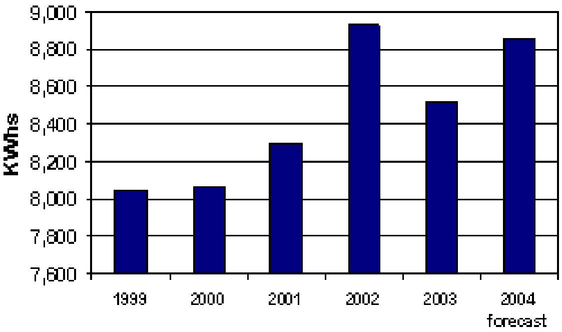
- **Exelon Way process improvements continue to increase productivity and streamline operations**
- **"Completing the merger" eliminated more than 550 positions in past 12 months**

Total cost per customer continues to improve.

Growing Customer Base and Usage

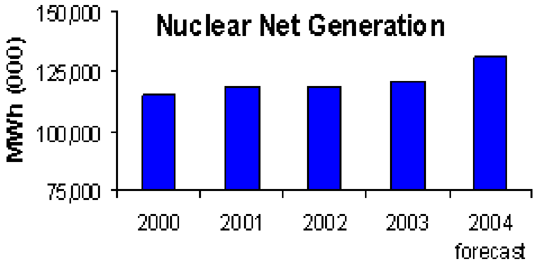
- Customer base is growing steadily – 4.7% since 1999
- Residential electric usage is increasing
- Residential sales are expected to increase by 4.3% in 2004


Energy Delivery Customers

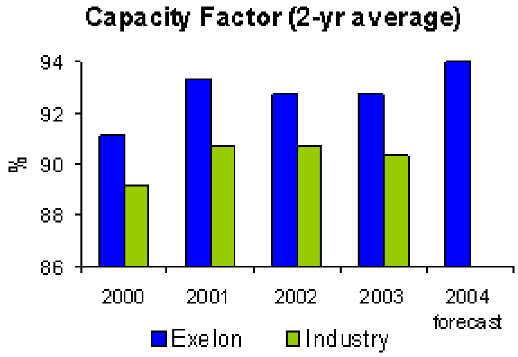

Residential Customer Usage

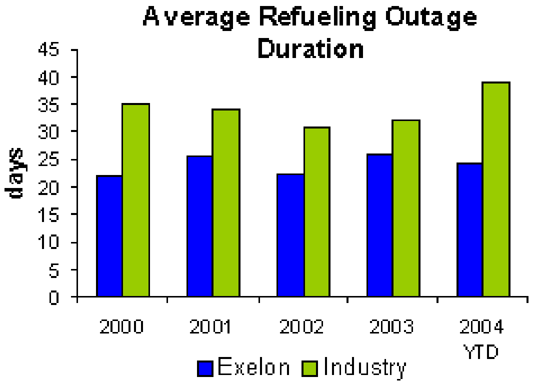
Customer base is growing and using more energy

Nuclear Performance - Production



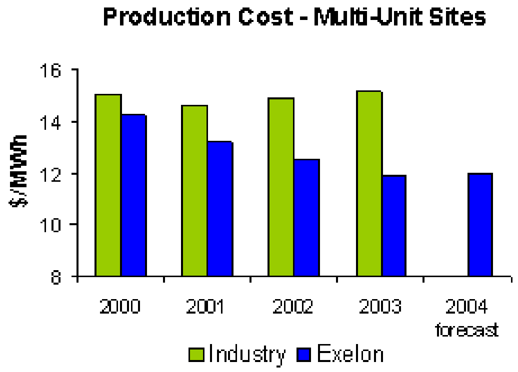
- Consistent growth in generation output
- Consistently high capacity factors
- Consistent performance and industry leadership in refueling outage execution

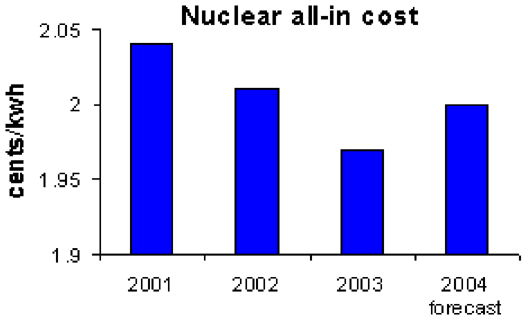




Nuclear production performance is consistently good.

Nuclear Performance - Cost





Exelon Nuclear is consistently cost competitive

- Consistent improvement in production cost
- Consistent improvement in all-in cost
- Exelon's 5 big dual unit sites are the 5 lowest cost plants in the U.S. -- they define the top decile of performance

Exelon Nuclear's low cost generation is a significant competitive advantage.

Management Strength & Continuity

Exelon

- Exelon Nuclear has a strong bench of skilled, seasoned leaders
  - The senior management team has extensive Exelon experience
    - Key nuclear senior corporate management have experience as Exelon site vice presidents
  - All ten site vice presidents have served as plant managers
- We maintain a balance of external recruits and internally developed talent
- We enforce a planned career development experience program for all key operating jobs that requires specific plant experience
- Retention is under control, and Nuclear has been able to supply talent throughout the company

Exelon Nuclear can count on management continuity and depth of experience.

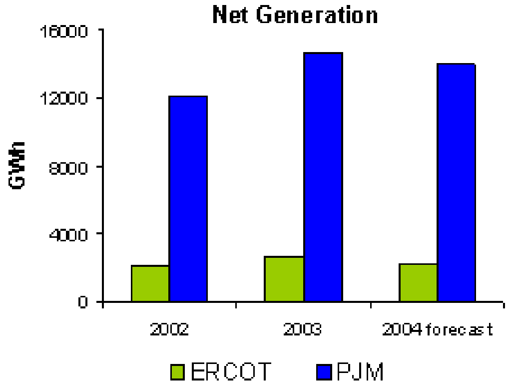
Nuclear Leadership in Operations

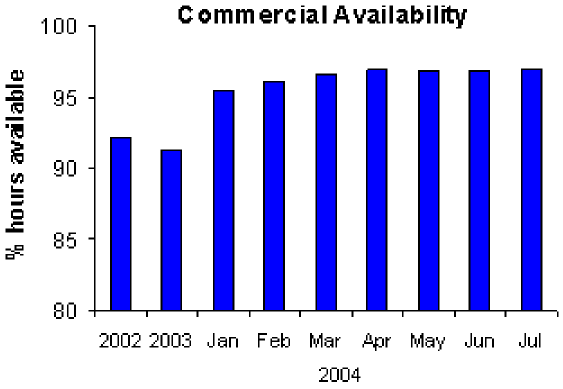
- The management model is fully implemented in Exelon Nuclear
  - Standard best programs and processes fleet-wide
  - Proven templates to get work done right
  - Standardization of tools and methods to capture synergies, share resources
  - Standard budgets and cost management tools across sites
  - Enables consistent, replicable results

- Exelon Nuclear maintains leadership positions in the U.S. nuclear industry
  - Materials Improvement Initiative
  - New Nuclear Plant Licensing
  - Industry Security Response
  - Executive leadership positions in INPO, NEI, EPRI, and Owners groups

Exelon Nuclear is a leader in nuclear business practices and policy development.

Exelon Power Improvements





- Condition-based overhauls are resulting in production improvements and economic gains
  - Production improvements: coal unit mill performance, steam unit boiler reliability, turbine reliability, feedwater heaters, condensers
  - >350 MW gained or recaptured through uprates and material condition improvement
  - Heat rate improvements achieved through unit overhauls have improved economic efficiency
- Ongoing process of asset optimization

Improved material condition, outage execution, and coordination are driving increased generation.

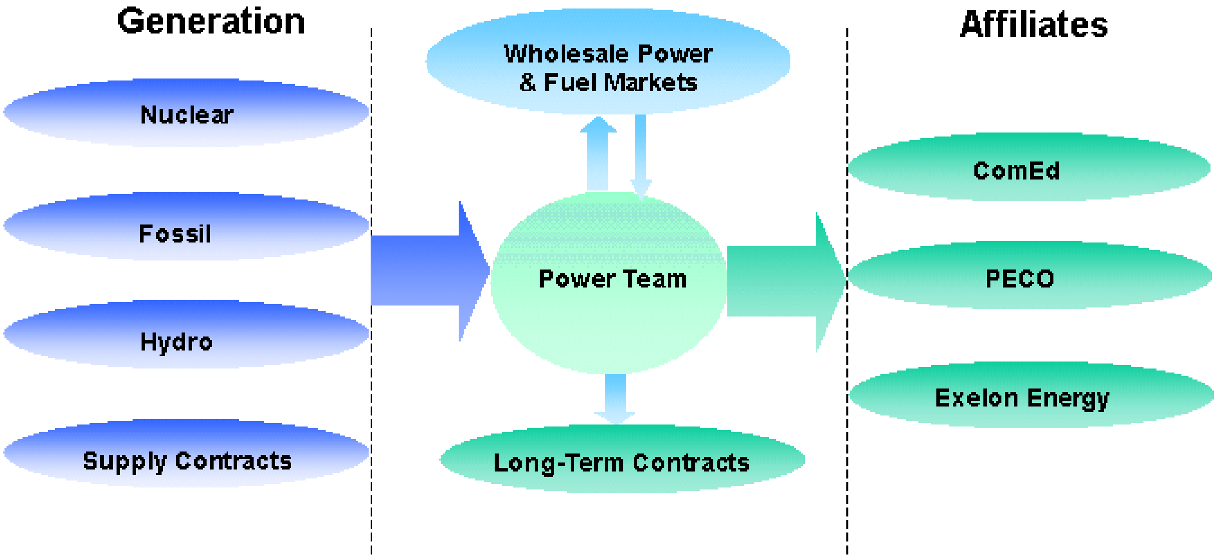
Power Marketing Update

Ian P. McLean
President, Power Team

Kenneth W. Cornew
Senior Vice President, Power Team

Exelon Investor Conference
New York City
August 19, 2004

Power Team: Value Added Intermediary



Generation

Nuclear

Fossil

Hydro

Supply Contracts

Wholesale Power & Fuel Markets

Power Team

Long-Term Contracts

Affiliates

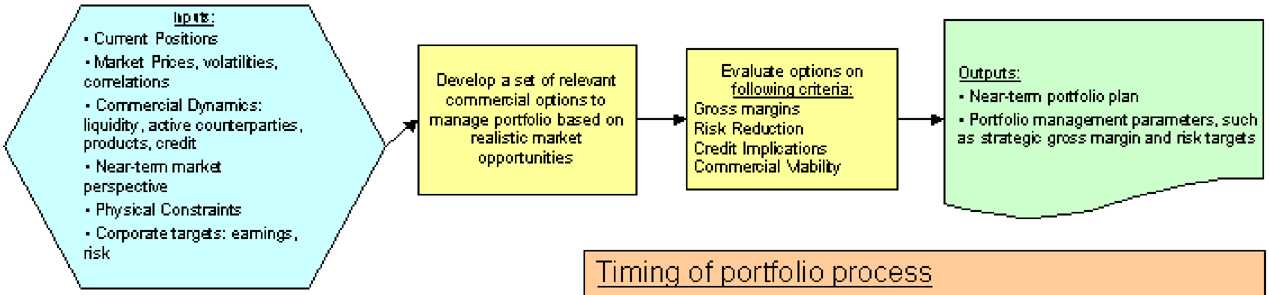
ComEd

PECO

Exelon Energy

Power Team manages the interaction between the generation portfolio and the wholesale customers and markets in order to reduce risk and optimize Exelon Generation profitability.

Portfolio Management Process



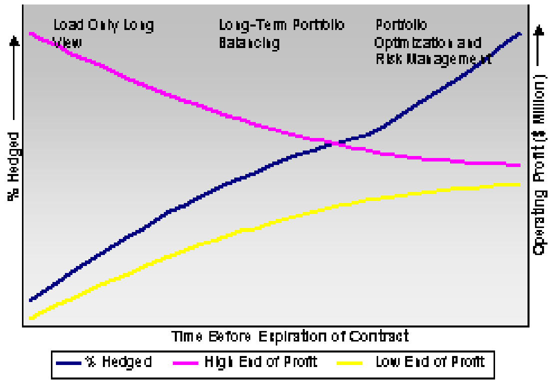
Inputs:
- Current Positions
- Market Prices, volatilities, correlations
- Commercial Dynamics: liquidity, active counterparties, products, credit
- Near-term market perspective
- Physical Constraints
- Corporate targets: earnings, risk

Develop a set of relevant commercial options to manage portfolio based on realistic market opportunities

Evaluate options on following criteria:
Gross margins
Risk Reduction
Credit Implications
Commercial Viability

Outputs:
- Near-term portfolio plan
- Portfolio management parameters, such as strategic gross margin and risk targets

Approach to Portfolio Management Over Time



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

The Wholesale Market Is Still Evolving

- Lack of “Organized Markets”
  - Bilateral markets as another source of value
- Despite regions having surplus, there are customers with significant unmet needs in the next several years
  - Contract expiration
  - Load growth
- Very few active and creditworthy players
- Increased need for risk management
  - Reserve margins beginning to tighten
  - Gas volatility increasing

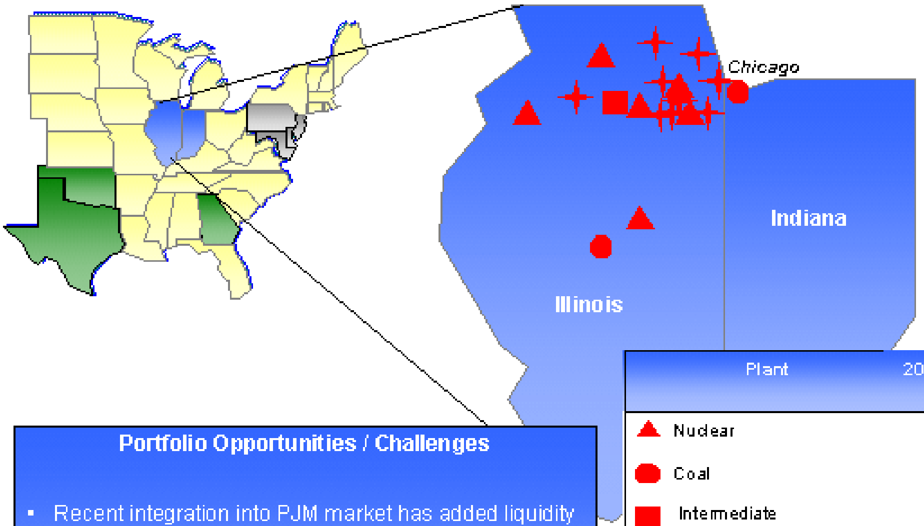
Exelon is one of a handful of companies positioned to capitalize on these dynamics.

Coordinated Marketing Strategy

- Generation marketing strategy is aimed at delivering results
  - Improving margins
  - Securing long-term customer base
  - Managing earnings risk
- Long-term focus on strategy, planning and analysis
- All unregulated operations under one roof
- Coordinated use of short, mid, and long-term channels
- Reduce merchant exposure to strengthen balance sheet

Exelon's strategy – proactive focus on capturing opportunities.

Midwest Portfolio Characteristics



Plant	2005 Capacity (MW)	Avg. Variable Cost ($/MWh)
▲ Nuclear	10,877	$ 4.50
● Coal	1,623	$ 20.00
■ Intermediate	0	$ 34.00
✦ Peakers*	3,631	$ 75.00
Total Capacity	16,131	
Demand - PPA		
Annual GWh (2005)	75,293	
Peak Load (MW)	18,375	

* Assuming $6.30/MMBtu gas price

Portfolio Opportunities / Challenges

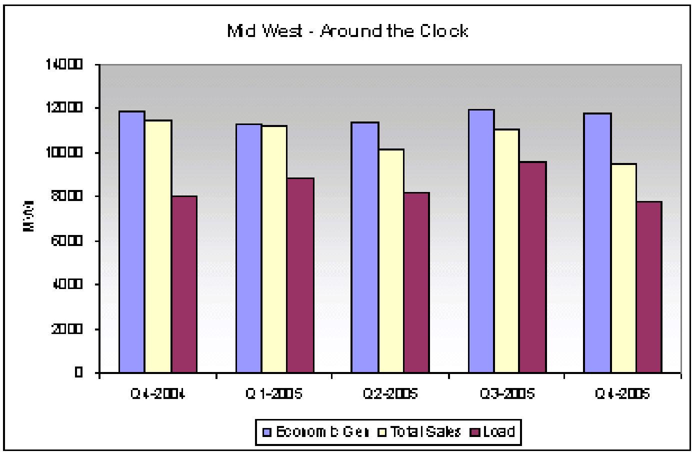
- Recent integration into PJM market has added liquidity to the standard and structured product markets
- Length from base-load units to participate in higher market prices
- Load following capability is purchased from third parties and the power pool
- Lack of liquidity in off-peak market creates a challenge for portfolio management
- Analysis of the effects of AEP integration into PJM is underway

Midwest: Key Elements

Commodity	Impact	Comments
Natural Gas Prices	◑	• Gas is on the margin for some on peak hours, and we are primarily a base-load generator
Oil Prices	○	• Oil is not on the margin a significant amount of time and does not drive prices
Gas Spark	◔	• Compared to base-load length, spark length does not significantly drive margins
Oil Spark	○	• Minimal oil capacity in the portfolio

Significant ●

Insignificant ○



Forecast

Portfolio Management 2004

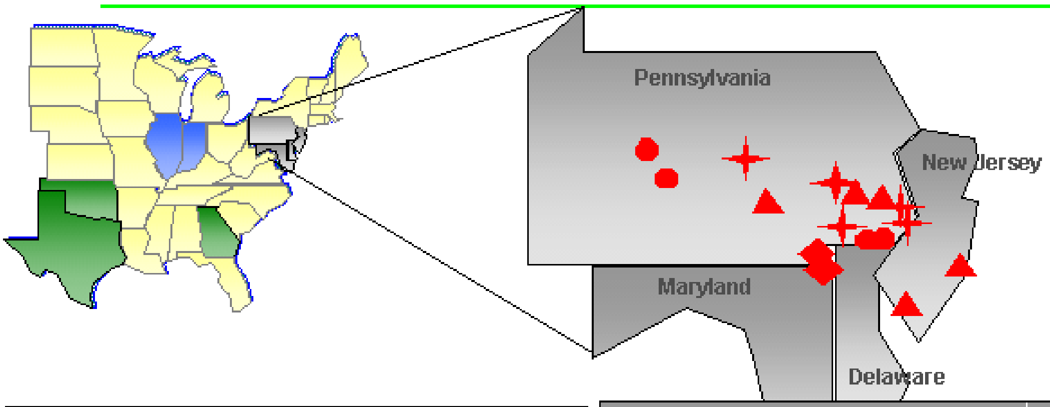
- Hedged for the remainder of the year around the clock
- Manage operational risk of baseload length in the off peak hours

Portfolio Management in 2005

- Includes changes in generation stack due to roll off of PPAs
- Length remains in the second, third and fourth quarters
- Natural gas needs for peakers is covered as power sales are made
- Acquired intermediate products from bilateral market to better match assets and load obligations
- RES migration assumptions can vary in a range of 2000 MWs; utilize options to cover floating RES risk

RES = Retail Energy Supplier

Mid-Atlantic Portfolio Characteristics



Portfolio Opportunities / Challenges

- We operate in a centrally dispatched power pool
- More liquidity in the PJM region creates more capability to hedge
- CCGTs are on the margin for a majority of the on-peak hours and many of the summer off-peak hours
- Length from base load units to participate in higher market prices
- Capability to follow load is dependent on structured transactions and utilization of the pool

CCGTs = Combined-cycle gas turbines

Plant	2005 Capacity (MW)	Average Variable Cost ($/Mwh)
▲ Nuclear	5,767	5.00
◆ Hydro	1,618	NA
● Coal	1,441	$34.00
■ LFG/Cogen/Contract	406	$50.00
✦ Resid Oil and Peakers*	1,975	$65 resid oil / $100 gas
Total Capacity	11,207	
Demand - PPA		
Annual (Gwh) (2005)	37,829	
PPA Peak Load (MW)	7,820	

* Assuming $6.30/MMBtu gas price

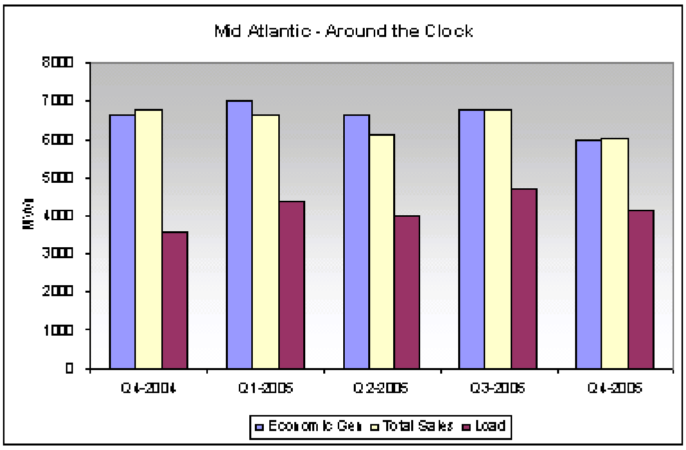
LFG = Landfill gas

Mid-Atlantic: Key Elements

Commodity	Impact	Comments
Natural Gas Prices	◐	- Gas is increasingly on the margin - We have a substantial amount of base-load capacity. Therefore, gas price movements drive the power market and affect our margins.
Oil Prices	◐	- Oil on the margin a significant proportion of the time
Gas Spark	◔	- We have a relatively insignificant amount of gas peakers as compared to base-load length
Oil Spark	◐	- Significant oil-based capacity in the portfolio

Significant ●

Insignificant ○



Forecast

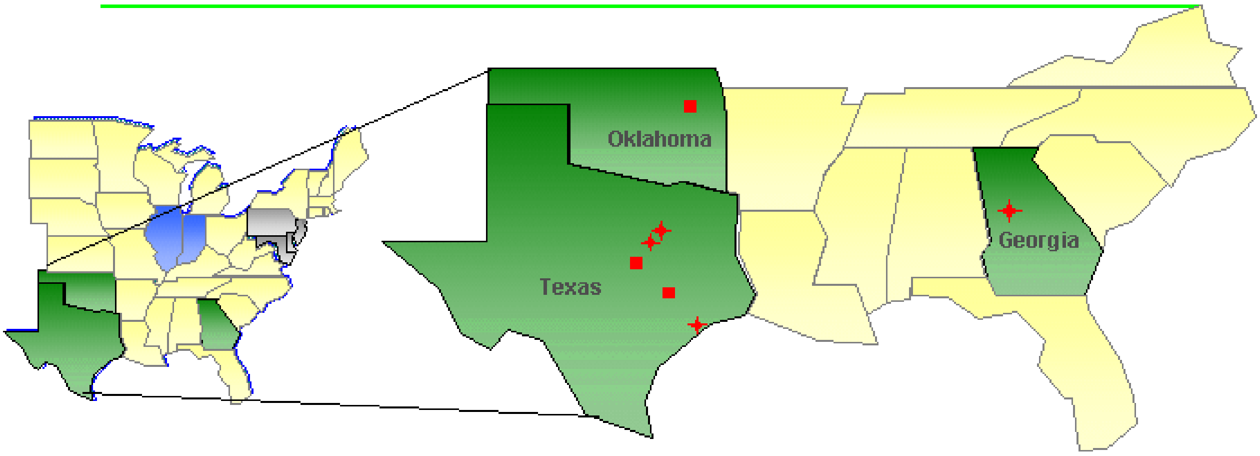
Portfolio Management 2004

- Hedged in outage months
- Upside participation with daily dispatchable units

Portfolio Management 2005

- Getting well hedged as 2005 approaches
- Acquired intermediate products to complement existing asset portfolio
- Upside participation and downside protection provided with option strategies in power and fuels markets
- Increased native load obligations with switching assumptions
- Congestion management strategies are aligned with portfolio management process

ERCOT/South Portfolio Characteristics



Portfolio Opportunities / Challenges

- The portfolio assets are in the ERCOT, SPP and SERC regions
- The combined cycle units are generally hedged forward; remaining length and peaker length used for opportunistic sales
- ERCOT ISO often runs the peakers for local reliability reasons

Plant	Capacity	Average Variable Cost ($/Mwh)
🟥 Combined Cycle*	1,975 MW	$50.50
✦ Peakers*	3,394 MW	$75.00
Total Capacity	5,369 MW	
Summer Toll**	2,334 MW	

* Assuming $6.30/MMBtu gas price

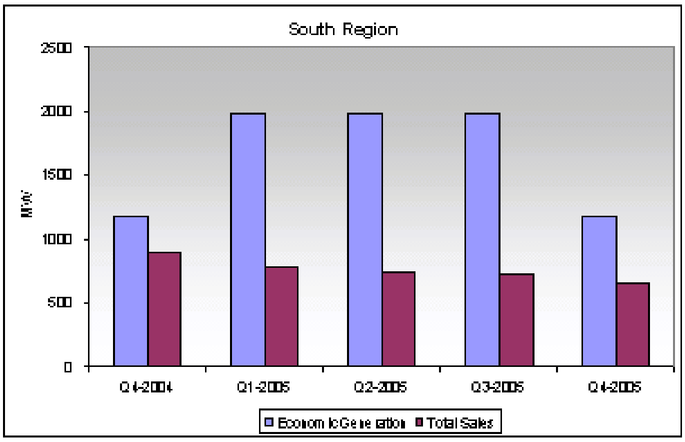
** TXU tolling deal totaling 2,334 MW

ERCOT/South: Key Elements

Commodity	Impact	Comments
Natural Gas Prices	◔	• Gas on the margin a significant proportion of the time; however, spark determines regional profit
Oil Prices	○	• Oil not on the margin in the region
Gas Spark	●	• The entire portfolio is spark based; 40% are high efficiency combined-cycle units
Oil Spark	○	• Minimal oil capacity

Significant ●

Insignificant ○



Forecast

Portfolio Management in 2004
Portfolio well hedged for the balance of the year
Portfolio Management in 2005
Portfolio has been partially hedged for 2005; market liquidity is increasing as 2005 approaches
Natural gas is purchased for all forward power sales
High heat rate units provide support for sales strategy and the ability to sell call options

Note: Economic Generation only – excludes higher heat rate units; excludes TXU Toll against Handley, Mountain Creek

Portfolio Sensitivities for Generation Co.

Gas Price Sensitivity [1] ($ million pre-tax)	Gas +20%	Gas –20%
2004	$13	($13)
2005	$15	$4
Power Price Sensitivity [2] ($ million pre-tax)	**Power +$1.00**	**Power -$1.00**
2004	$5	($4)
2005	$22	($20)
Coal Price Sensitivity [3] ($ million pre-tax)	**PRB [4] Coal +$1.00**	**PRB [4] Coal -$1.00**
2004	$1	($1)
2005	$6	($6)

Notes:
1. Gas prices were changed with a correlated change in power prices (power prices in the South and East are more significantly affected by gas prices than in the Midwest); coal prices were held constant
2. Power prices were changed; fuel prices were held constant
3. Effect of coal prices passed through to length in the off-peak Midwest position; all other commodities held constant
4. Powder River Basin Coal

Generation: Strategic Overview and Economic Drivers

John F. Young
President, Exelon Generation

Exelon Investor Conference
New York City
August 19, 2004

Exelon Generation: An Overview

Exelon Generation

Competitive Energy Supply Business

Exelon Nuclear

Operates and maintains Exelon's nuclear assets

Nuclear Capacity: 16.6 GW

Exelon Power

Operates and maintains Exelon's fossil and hydro units

Fossil Capacity: 7.1 GW
Hydro Capacity: 1.6 GW

Power Team

Optimizes value of energy supply business, manages earnings risk and markets long-term power

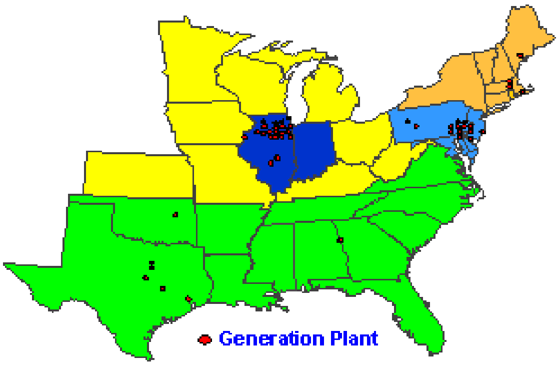
Contracted Capacity: 12.7 GW

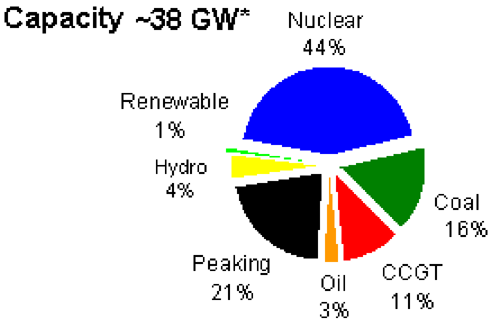
Exelon Generation:

- Premier nuclear operator, achieving top quartile performance during 2000 – 2003
- Reliable and commercially responsive fossil operations, significantly improved over previous years
- Experienced leader in wholesale power marketing and risk management
- Operational and commercial excellence in the integrated competitive energy supply business

Our Regional Positions

Midwest	Mid-Atlantic	ERCOT & South
▪ Owned Generation: 11.4 GW ▪ Contracted Generation: 9.6 GW ▪ ComEd Control Area Peak Load: 22.1 GW	▪ Owned Generation: 11.2 GW ▪ Contracted Generation: 0.3 GW ▪ PECO Control Area Peak Load: 8.2 GW	▪ Owned Generation: 2.5 GW ▪ Contracted Generation: 2.9 GW ▪ TXU Tolling Contract: 2.3 GW

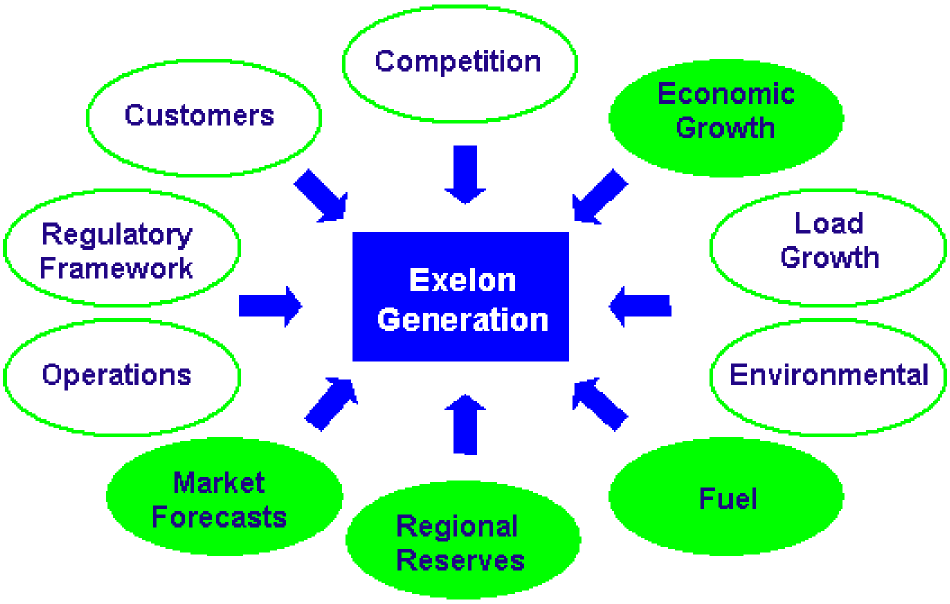




*Includes long-term contracts
CCGT = combined-cycle gas turbine

Exelon follows a linked load and generation strategy across three primary regions.

Drivers of Our Business



Competition

Customers

Economic Growth

Regulatory Framework

Exelon Generation

Load Growth

Operations

Environmental

Market Forecasts

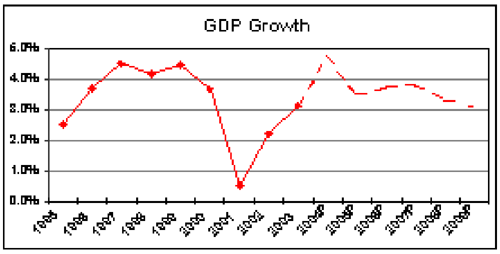
Regional Reserves

Fuel

Exelon understands its business drivers.

Economic Growth Drives the Regional Demand for Electricity

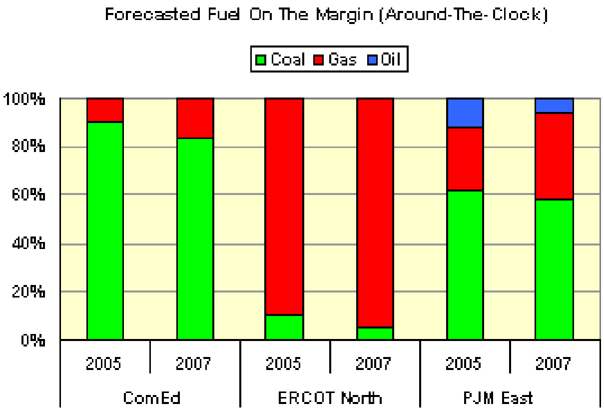
- Real U.S. GDP is expected to grow at an average of 3.5% over the next five years
- Economic growth will vary by region
  - Mid-Atlantic 3.4%
  - Midwest 3.2%
  - Texas 4.2%
- Nationwide, electricity use is expected to grow at about 2.2% per year, strongest growth in the South and West



P= Projected

International Fuel Markets Impact Domestic Electricity Prices

- Fuel prices are higher than in the '90's, unlikely to return to the same low levels
- Strong demand and little excess supply have driven oil prices higher
- High oil prices and tight domestic supply cause high gas prices, LNG may provide relief by the end of the decade
  - Gas is increasingly becoming the fuel on the margin, setting power prices
- Coal spot market prices have increased sharply over the last year, likely to decline over time as capacity increases



Higher fossil fuel prices give an advantage to Exelon's low-cost nuclear generation.

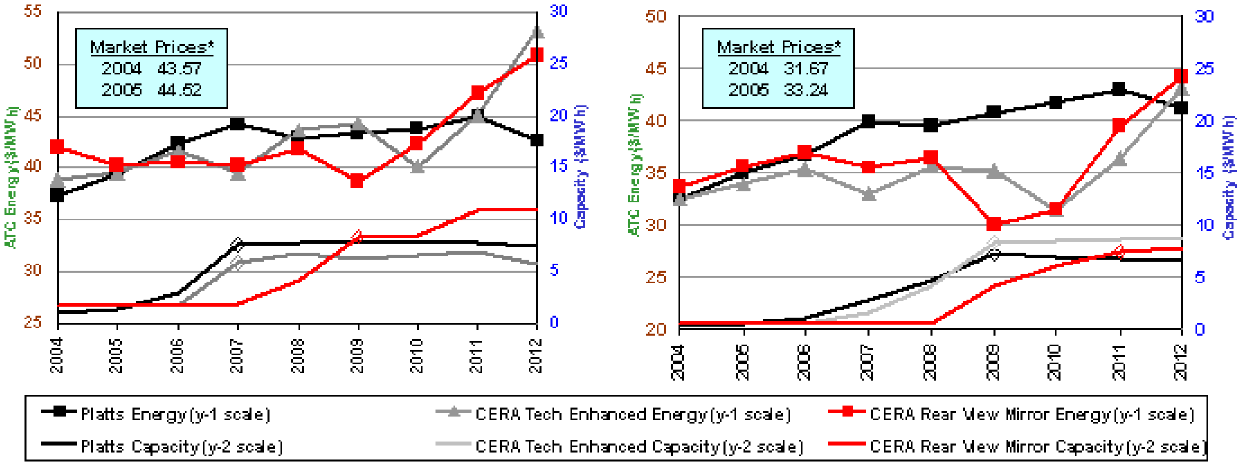
Regional and Sub-Regional Reserve Margins Are Declining

- Exelon's regional and sub-regional (MAIN ComEd, PJM East and ERCOT North) projected planning reserve margins are expected to decline at a faster rate than previously forecasted due to:
  - Economic recovery translating into higher projected electricity growth rates
  - Recent retirement/mothballing of generation assets
- Sub-regional markets are projected to rely more on existing transmission for importing economic power

Decreasing reserve margins are expected to lead to higher values for capacity and an increasing concern about reliability.

Consultant Price Forecasts

PJM Energy and Capacity ($/MWh) **MAIN Energy and Capacity ($/MWh)**



◇ Projected new supply added * Current observable market prices

Sources: Platts Research and Consulting Outlook For Power in North America (Q2 2004)
CERA New Realities, New Risks: North American Power and Gas Scenarios (December 2003)

Industry price forecasts are driven by load growth, retirements and fuel prices.

Exelon Generation: Value Maximization

Strategic Decisions

- Integrated business model
- Balanced generation portfolio – fuel diversity, geographic location and dispatch mix
- Continuous asset rationalization
- Knowledge of market fundamentals
- Financial discipline

Assets

Integrated Business Positioned for Future Opportunities

Assets

Operational Excellence

Commercial Excellence

Assets

- Rigorous performance management
- Productivity improvement
- Aggressive management of fuel, O&M and capital cost

- Solid risk management, optimizing output of generation fleet and contracted capacity
- Commercial responsiveness and reliability, prepared to "run for the market"
- Long-term marketing to provide earnings growth and an enhanced balance set
- Low cost fuel supply

Exelon Generation: Sustained Excellence

- Operating plans based on business imperatives
- Continued focus on performance discipline
- Experienced leader in risk management
- Deep bench of talent and experience
- Effectively integrated portfolio strategy
- Positioned to capitalize on market dynamics

Illinois Update and POLR Pricing

Anne R. Pramaggiore
Vice President, ComEd

Kenneth W. Cornew
Senior Vice President, Power Team

Exelon Investor Conference
New York City
August 19, 2004

Post-2006 Overview

- Debate around Post-2006 issues occurring in ICC-sponsored workshop process:
  - Commissioner Erin O'Connell-Diaz serves as Chair of the workshop process
  - Workshops began April 29, 2004, with a kick-off symposium and will end in September 2004
  - ICC plans to submit Report to Illinois General Assembly on Post-2006 workshop outcome in fourth quarter 2004
  - First half of workshop process served as a forum for education of stakeholders on key issues, including specific supply procurement models, wholesale market development, demand side management and RTO mechanics
  - In final half of workshop process, stakeholders have generated robust debate of key procurement models, their features and impacts

ICC Workshop Process Timeline

ICC Process Launch
Stakeholder
Positions Identified

April '04

Key Milestones:

- ICC Workshop Process finalized 4/1
- 5 Working Groups and Conveners appointed:
  - Procurement
  - Rates
  - Competition
  - Service Obligations
  - Energy Assistance
- Intervenor Comments filed with ICC 4/22
- ICC Kick-off Symposium 4/29

Education
Process

May - June '04

Key Milestones:

- 12 Scenarios Developed:
  - NJ/MD/Full Requirements
  - Horizontal/Integrated Resource Planning
  - Rate Freeze extension
  - Affiliate Full Requirements
  - Return to Regulation
- 5/20 Illinois State Symposium
  - NJ panel
  - Role of renewable energy; energy efficiency; demand response
- Joint ICC Working Group Session 6/22 – 6/23
  - RTO discussion
  - State Model Panel discussion
    - NJ
    - MD
    - TX
    - CA

Scenario
Analysis

July '04 - August '04

Key Milestones:

- Issues analysis and consensus development
- Joint workshop on RTO market monitoring 7/20

Commission
Report

September - November '04

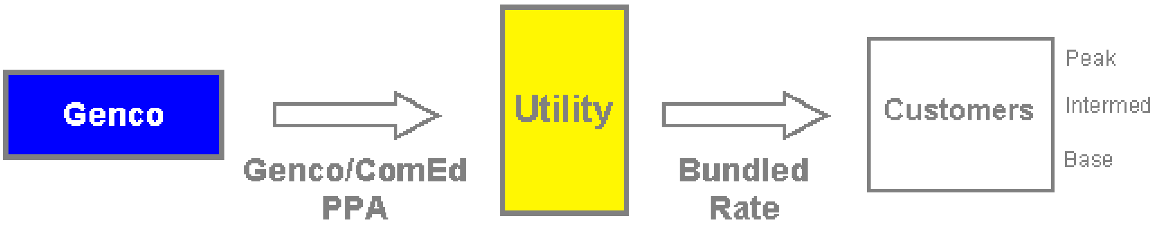
Key Milestones:

- Working Groups Report to ICC
- Commission Report to Illinois General Assembly

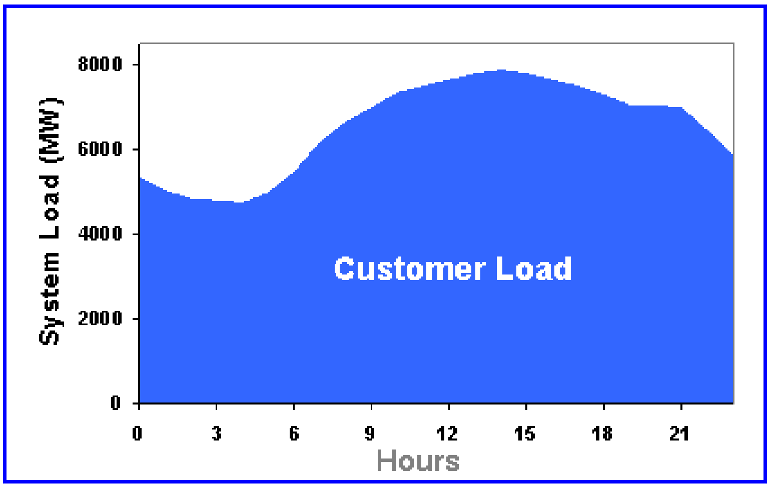
ICC Workshop Process Recap

- 12 scenarios are being analyzed, most are variations of two basic models:
  1. "Full Requirements" procurement model (NJ/MD)
  2. "Portfolio Management" procurement model (CA)
- Strong support for competitive procurement has emerged, with ongoing debate concerning:
  - The specific procurement model
  - The degree and timing of stakeholder and regulatory involvement in the procurement process
  - The adequacy of wholesale market development
  - Rate stability for residential customers

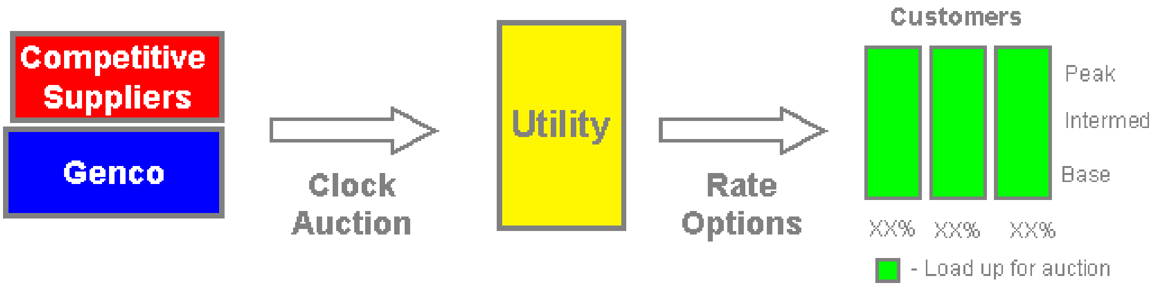
Current Model



- Genco is sole supplier of customer load through a PPA with ComEd
- Bundled service for customers >3MW has been declared competitive



Competitive Procurement Model



Competitive Suppliers

Genco

Clock Auction

Utility

Rate Options

Customers

Peak

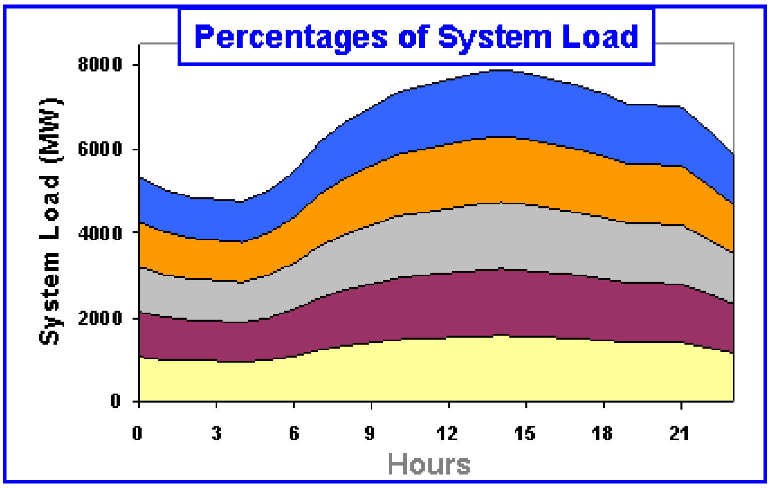
Intermed

Base

XX% XX% XX%

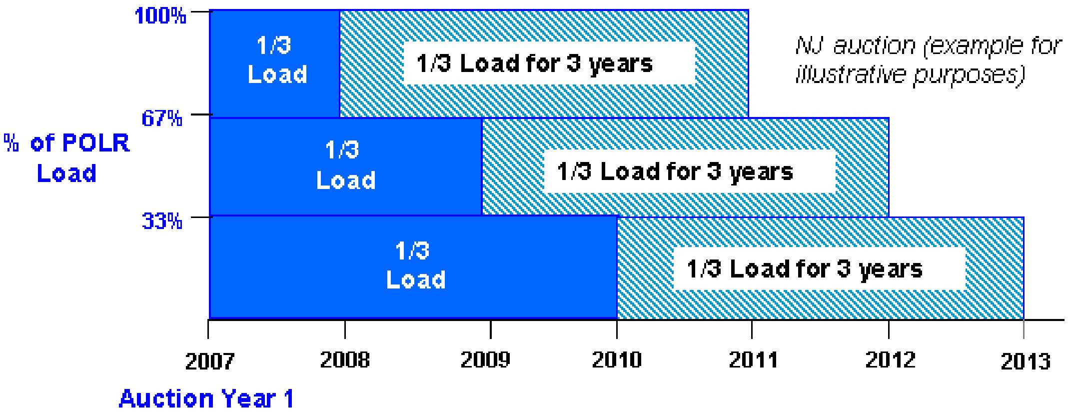
🟩 - Load up for auction

- Multiple winning bidders would supply customer load in vertical slices (fixed % of hourly energy demand)
- New rates determined by auction results



Percentages of System Load

NJ Auction Design Example



NJ auction (example for illustrative purposes)

- Rate stability concerns can be addressed through staggered purchases of full requirements product.
- In this example, the first year auction divides the POLR load into thirds with 1/3 bid as a one-year product, 1/3 bid as a two-year product and 1/3 bid as a three-year product.
- In subsequent years, all auctions are for three-year products.

BGS Auction

Exelon

Overview

- Basic Generation Service (BGS): Over 11,000 MW of load auctioned across 4 utilities in New Jersey in February 2004
- Over 15 winners in the auctions
- Winning bids for POLR product were 50-60% above the standard block product at PJM West Hub

Lessons Learned

- Risk management of the BGS full requirement contracts for the winners was critical
  - Gas and power prices spiked significantly after the auction
- Congestion risk needs to be managed largely through physical assets within the congested zone
- Market liquidity has an impact on the costs over the standard block product
  - Limited liquidity in the Midwest as compared to PJM likely to increase costs of full requirement contracts

Full Requirements Contracts

- POLR (Provider of Last Resort) is a Full Requirements Contract
  - Delivering party takes all obligations associated with serving a load at a fixed price
  - Obligations include energy, capacity and ancillary services
  - Delivering party assumes all the risks in the full requirements contract including customer migration risk

Components of a Full Requirements Price

A. Underlying Energy
- Standard Block Energy Price
- Load Shape Price
- Volume Risk

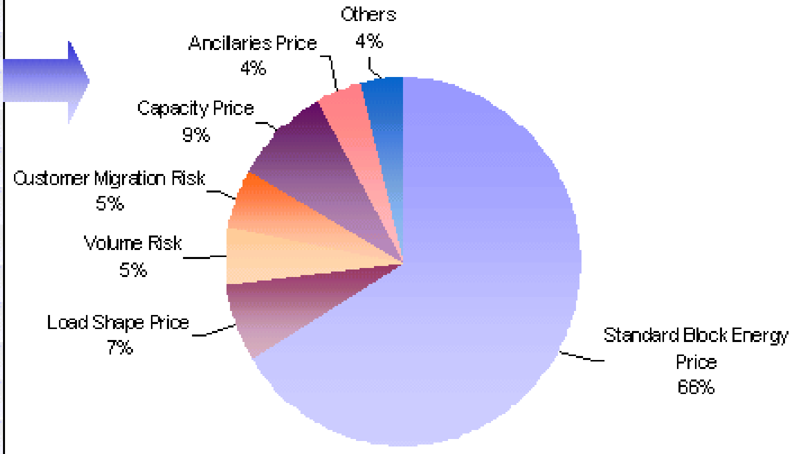
B. Customer Migration Risk

C. Capacity Price

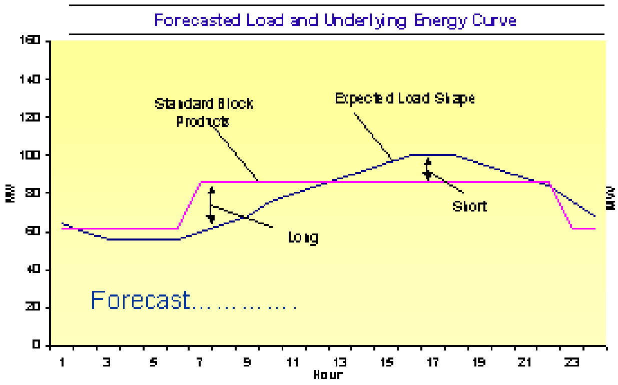
D. Ancillaries Price

E. Other Risks
- Transmission (Congestion)
- Credit
- Regulatory

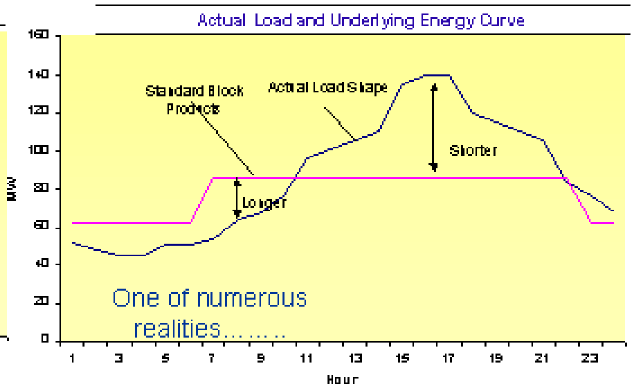
Components of an Example Full Requirements Contract



Risk Management of Full Requirements



Forecasted Load and Underlying Energy Curve



Actual Load and Underlying Energy Curve

Components of a Full Requirements Price	Risk Management Strategy	Level of Risk Mitigation
A. Underlying Energy		
- Standard Block Energy Price	Buy standard blocks / self supply	High
- Load Shape Price	Buy shaped products / self supply	High
- Volume Risk	Option strategies / self supply	Medium
B. Customer Migration Risk	Option strategies	Low
C. Capacity Price	Buy capacity / self supply	High
D. Ancillaries Price	Buy ancillary services / self supply	High
E. Other Risks		
- Congestion	Congestion related options / local supply	Medium
- Credit	Contractual risk management	High
- Regulatory	Contractual management	Low

Financial Overview

Robert S. Shapard
Executive Vice President & Chief Financial Officer

Exelon Investor Conference
New York City
August 19, 2004

Financial Overview

- 2004 Performance and Outlook
- 2005 Guidance
- Ongoing Earnings Drivers
- ComEd Transition
    - 2007 Energy Pricing
    - 2007 Distribution Rates
    - Goodwill
- Financial Plan
    - Dividend Policy
    - Debt Targets
    - Use of Available Cash

Year-To-Date Results

(EPS in $)		Jun-04		Jun-03
Adjusted (non-GAAP) Operating EPS	$	1.29	$	1.22
GAAP EPS	$	1.40	$	1.12

(Cash in Million $)		Jun-04		2004 Goal
Cash Flow From Normal Business	$	200	$	300
Free Cash Flow	$	588	$	750

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

Year-To-Date Results

Adjusted (non-GAAP) Operating EPS		Actual vs. Prior Year YTD
2003 Actual		**$ 1.22**
Profit Drivers:		
Weather		-
Enterprises (approximately breakeven)		0.09
Genco RNF (primarily wholesale prices)		0.06
Lower Interest Expense		0.05
AmerGen		0.02
Loss Drivers:		
Energy Delivery RNF		
- CTC	(0.11)	
- Growth/Volume	0.09	(0.02)
Depreciation and Amortization		(0.05)
More Nuclear Outages		(0.03)
Sithe (mark-to-market)		(0.02)
Share Dilution		(0.02)
Other		-
2004 Actual		**$ 1.29**

Note: RNF = Revenue net Fuel/Purchased power

See presentation appendix for adjusted (non-GAAP) operating EPS reconciliation to GAAP.

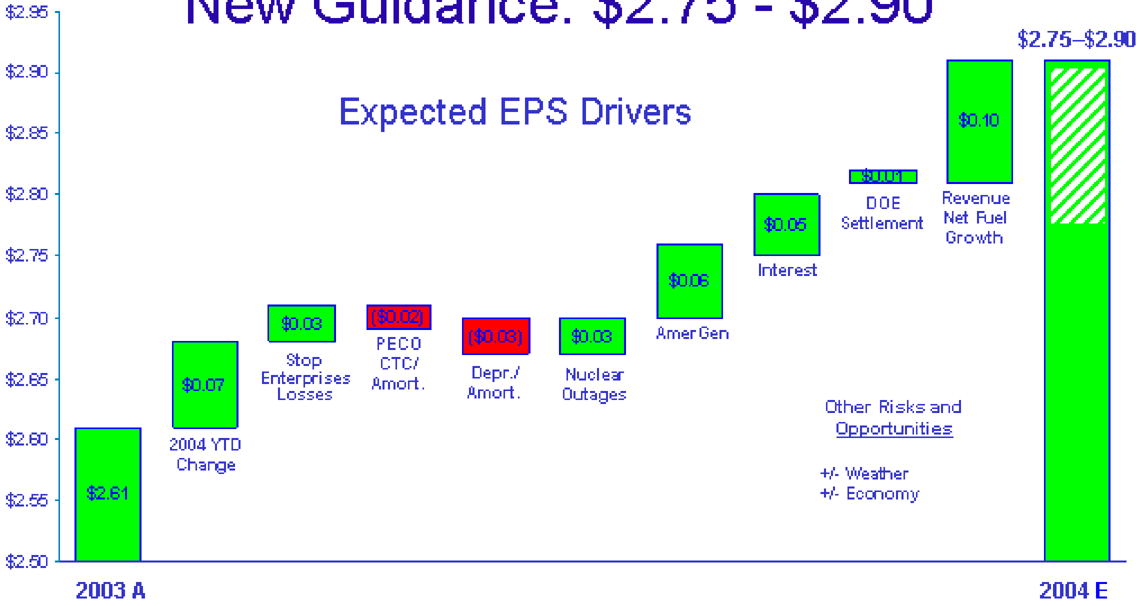
Exelon 2004 Financial Scorecard

($ in millions, except per share data)	Measure	To-date (through June)	2004 Target/Estimate	Status
Adjusted (non-GAAP) Operating EPS	Year-to-date	$1.29	$2.75 - $2.90 (New Guidance)	On track
Exelon Way O&M Savings (pre-tax)	Program-to-date	$227	$210	On track
	Year-over-year	$64	$47	On track
Exelon Way Cap Ex Savings	Program-to-date	$188	$200	On track
	Year-over-year	$121	$133	On track
Free Cash Flow	Year-to-date	$588	$750	On track
Divestitures/Sales	Net cash proceeds	$365	$375	On track
Credit Measures	FFO Interest Coverage*	6.5x (2003)	8.0x	On track
	Debt to Total Cap*	51%	48%	On track

* Excludes transition debt and Boston Generating Facility debt

Note: See presentation appendix for O&M and Cap Ex savings, EPS, Free Cash Flow, FFO (Funds from Operations) and Debt to Total Cap reconciliations to GAAP.

2004 Adjusted (non-GAAP) Operating EPS
New Guidance: $2.75 - $2.90*



* Reflects 2-for-1 stock split effective 5/5/04.

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

Items may not add due to rounding.

2004 Expected O&M Savings

(Pre-tax $ in Millions)

	2003 Baseline / 2004 O&M Comparison	
	2003 Baseline	**2004 Forecast**
Total Forecasted Operating & Maintenance (O&M) *	**$ 4,075 (a)**	**$ 3,810 (b)**
Reconciliation Items		
- Exclude Enterprises and Boston Generating (BG) **	(795)	(240)
- Include AmerGen at 100%, Net of Accretion	380	N/A
- Exclude Incremental Outage Impact	N/A	(25)
- Exclude Sithe	N/A	(60)
- Include Payroll Taxes	110	100
- Exclude Exelon Way Severance	N/A	(25)
- Exclude Synthetic Fuel-Producing Facilities	N/A	(50)
Adjusted Total O&M	**$ 3,770**	**3,510**
2003 Baseline		**3,770**
Net Expected Savings from 2003 Baseline		**$ 260**

* Excludes nuclear decommissioning accretion (offset by trust fund earnings in Other Income) and 2003 Global Settlement; includes Exelon Energy (transferred to Generation Co.)

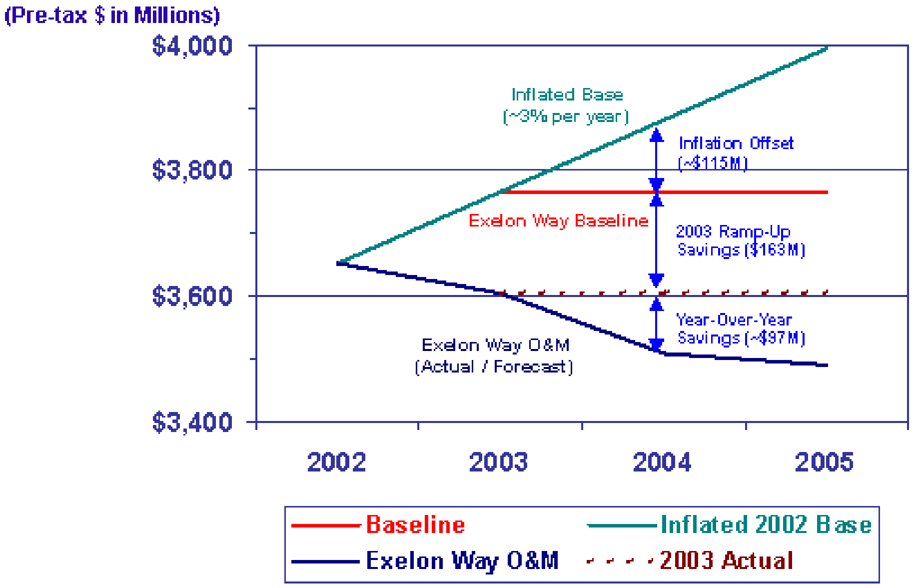
** Enterprises and Boston Generating net of functional corporate costs

(a) Forecast from 8/6/03 Investor Conference - Total Spend Baseline

(b) Current forecast

Note: See presentation appendix for The Exelon Way savings and reconciliation to GAAP.

The Exelon Way 2004 O&M Savings



- 2003 ramp-up savings of $163M more than offset inflation assumed in 2003 operating plan
- 2004 savings of ~$260M versus baseline includes ramp-up savings carried forward plus additional projected year-over-year savings of ~$97M
- Exelon Way initiatives also offset ~$115M escalated costs associated with wage/benefit increases plus general inflation for total 2004 savings impact of ~$375M

Note: See presentation appendix for The Exelon Way savings and reconciliation to GAAP.

2004 Expected Capital Savings

($ in Millions)

	2003 Baseline / 2004 Forecast	
	2003 Baseline	2004 Forecast
Total Forecasted Capital Expenditures (CapEx) *	$ 1,950 (a)	$ 1,920 (b)
Include AmerGen at 100%	170	N/A
Adjusted Total CapEx	2,120	1,920
2003 Baseline		2,120
Net Expected Savings from 2003 Baseline		$ 200

* Excludes Boston Generating
(a) Forecast from 8/6/03 Investor Conference - Total Spend Baseline
(b) Current Forecast

CapEx savings forecast on target, despite unplanned cost for added Nuclear security upgrades and higher than planned Energy Delivery growth spend

2004 Expected Cash Benefit

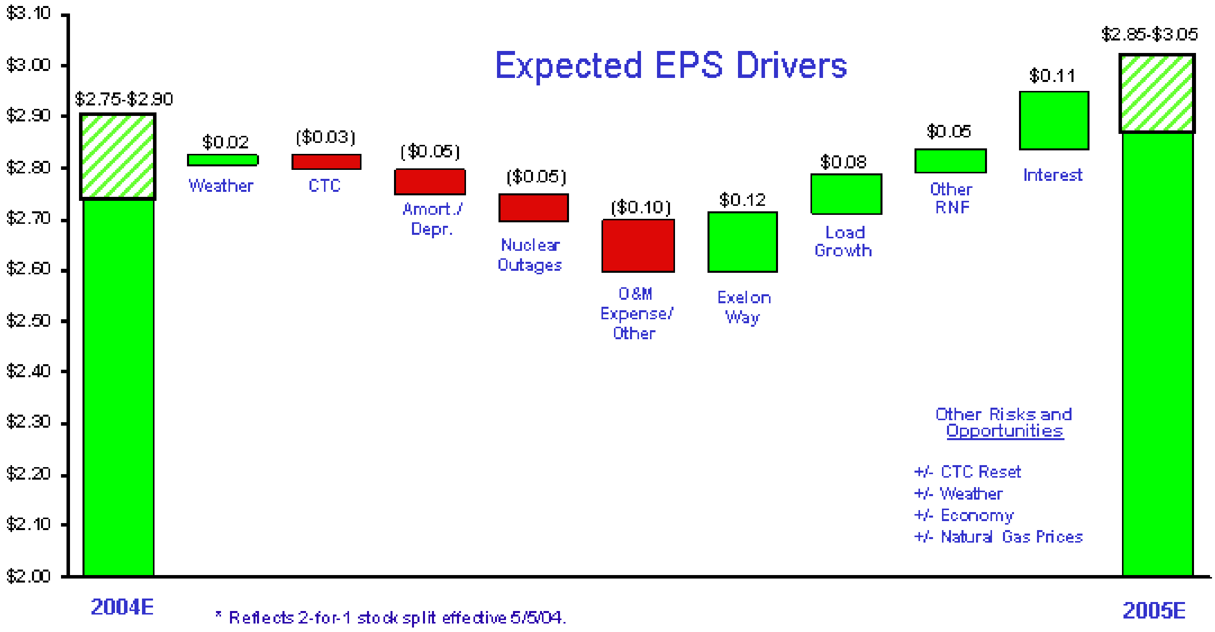
($ in Millions; 38% Tax Rate)

	Pre-Tax	After-Tax
O&M Savings	$ 260	$ 160
Capital Savings	200	200
Cash Savings		$ 360

Additional cash being generated from other Exelon Way initiatives (e.g., Power Team revenue enhancements, inventory management, land sales, etc.)

Note: See presentation appendix for The Exelon Way savings and reconciliation to GAAP.

2005 Adjusted (non-GAAP) Operating EPS Guidance: $2.85 - $3.05*



* Reflects 2-for-1 stock split effective 5/5/04.

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

Items may not add due to rounding.

Exelon Consolidated Key Assumptions

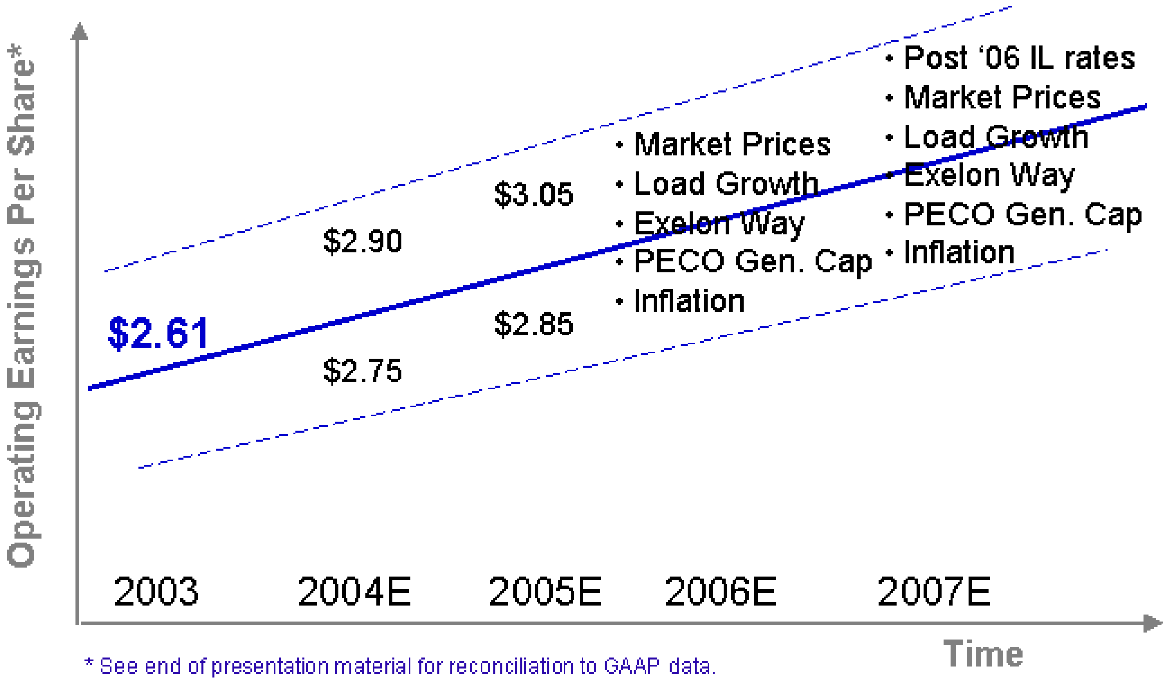
	2003A	2004E	2005E
Nuclear Capacity Factor (%)[1]	93.4	93.5	93.6
Total Genco Sales Ex Trading (GWhs)	224,672	217,700	187,900
Total Genco Sales to Intercompany (GWhs)	117,405	111,700	113,100
Total Market Sales (GWhs)	107,267	106,000	74,800
Volume Retention (%)			
PECO	92%	88%	93%
ComEd	81%	78%	76%
Delivery Growth Assumptions (%)[2]			
PECO	0.2%	2.9%	1.2%
ComEd	1.5%	2.6%	1.3%
Elec. Wholesale Mkt. ATC Price ($/MWh)			
MAIN	28.50	31.70	33.20
PJM	38.00	43.60	44.50
Effective Tax Rate (%)	34.7%	37.0%	36.7%

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

(1) Excludes Salem

(2) Weather Normalized

Ongoing Earnings Drivers

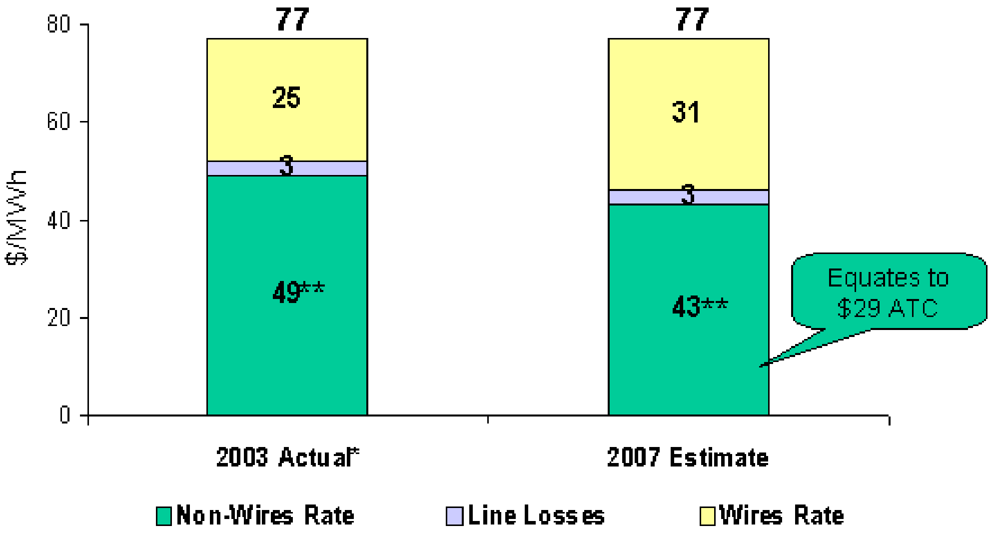


- Market Prices
- Load Growth
- Exelon Way
- PECO Gen. Cap
- Inflation

- Post '06 IL rates
- Market Prices
- Load Growth
- Exelon Way
- PECO Gen. Cap
- Inflation

* See end of presentation material for reconciliation to GAAP data.

ComEd Bundled Tariff for Mass Market



Assumes increase in wires charges to recover increased investment in transmission and distribution infrastructure and costs.

* Representative of unbundling of existing tariff.

** Includes the cost of energy, capacity, ancillary services, load following, weather, switching and congestion.

Note: Mass Market represents residential and small commercial and industrial customer classes.

2007 ComEd POLR Price Sensitivity to Fuel Prices

HH Gas $/MMBTU \ PRB Coal $/Ton	$ 5	$ 7*	$ 9
$ 3	$/MWh $ 44	$ 45	$ 46
$ 5*	$ 48	$ 49**	$ 50
$ 7	$ 52	$ 54	$ 55

* Fuel prices assumed in CERA's 2007 MAIN ATC price forecast ("Technology Enhanced" scenario)

** POLR price assumed to be 1.5 x CERA's 2007 MAIN ATC price forecast of $32.95 per MWh

Assumptions for sensitivity analysis: Coal on the margin 80% of hours, 10,500 heat rate, 0.057 Tons/MMBTU. Gas on the margin 20% of hours, 7,200 heat rate. POLR price equates to 1.5 x ATC price.

2007 NYMEX Henry Hub gas price currently about $5.70/MMBTU

2007 Powder River Basin coal price currently about $8.30/Ton

ComEd Delivery Service Investments

(Proforma $ in Millions)	2003	2000	
Gross DST Plant	$ 10,670	$ 8,518	25%
LESS: Accumulated Depreciation	(4,580)	(3,747)	22%
PLUS: Other Addt's (CWIP, Mtrls, Oper. Reserves, OPEB)	(100)	(325)	69%
LESS: Deferred Taxes	(990)	(829)	19%
Rate Base	$ 5,000	$ 3,617	38%
Weighted Average Cost of Capital	9%	9%	
Authorized Return	450	326	
Gross Revenue Conversion Factor	1.66	1.67	
Authorized Return Grossed Up for Taxes	747	543	
Operating Expenses before Income Taxes	1,480	1,115	33%
Revenue Requirement	2,227	1,658	34%

ComEd has made significant investments in Delivery Rate Base and experienced significant increases in costs since the last rate case test year (2000).

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

Goodwill Overview

- ComEd and Exelon currently have $4.7 billion of goodwill which is tested for impairment annually on November 1st
- If the Enterprise Fair Market Value exceeds Capitalization Value, no impairment occurs
  - As ComEd is not publicly traded, its Enterprise Fair Market Value is determined based upon a multi-scenario discounted cash flow model
  - Future cash flows are discounted at a rate that approximates a risk-free rate (L-T Treasuries)
- At Exelon, EED is the reporting unit (comprised of ComEd and PECO), thus an impairment at ComEd may not lead to an impairment at Exelon
- Impairment of Goodwill has no cash impact

Optimizing Our Balance Sheet

- Exelon is committed to maintaining strong credit measures
- While Exelon's consolidated balance sheet is strong, ComEd's balance sheet needs to be strengthened to provide financial flexibility
- Our accelerated liability management plan will dramatically strengthen ComEd's balance sheet now by eliminating $1.2B in debt at ComEd in 2004

Projected 2005 Key Credit Ratios

Exelon FFO / Interest	8.1x
Exelon FFO / Debt	35%

Under a scenario where ½ of ComEd Goodwill is written-off and excluding Securitization Debt:

ComEd Equity Ratio	56%

Note: See presentation appendix for FFO (Funds from Operations)/Interest and and FFO/Debt reconciliations to GAAP.

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	2.86	6.98	9.84	-	-	-	-	-
2006E	2.98	7.51	10.49	240	150	60	$0.09	160
2007E	2.98	8.01	10.99	180	70	70	$0.11	120

Note: Estimates based on Exelon forecasted energy sales; approximate 35% effective income tax rate assumption

* Per table on page 7 of 2003 Form 10-K filing

** Cash impact before principal payments on securitization debt

Deploying Our Cash - Forecast

($ in Millions)	2004	2005	2006[1]	Total '04 - '06
Net Income[2]	1,890	1,960	2,040	5,890
Depreciation & Amortization[2]	1,580	1,640	1,850	5,070
Deferred Taxes/Other[2]	180	(70)	(250)	(140)
Cash From Operations[2]	3,650	3,530	3,640	10,820
Capital Expenditures	(1,920)	(1,870)	(1,680)	(5,470)
Net Cash From Operations[2]	1,730	1,660	1,960	5,350
Dividends (Jan-04 Level)	(730)	(730)	(730)	(2,190)
Available Cash Flow	1,000	930	1,230	3,160
Other Cash Flows				
Enterprises Sales	200	-	-	200
DOE Settlement	40	-	-	40
Sithe	180	200	-	380
Syn Fuel	50	30	20	100
Other Cash Flows	470	230	20	720
Total Net Cash Flow	1,470	1,160	1,250	3,880
Cash Uses				
Strengthen ComEd Balance Sheet	(1,200)	-	-	(1,200)
Other Retired Debt	(230)	(580)	(650)	(1,460)
Increase Dividend Payout[3]	(40)	(350)	(400)	(790)
Other Uses (i.e., stock buyback[4])	-	(250)	(200)	(450)
Net Cash Uses	(1,470)	(1,160)	(1,250)	(3,880)
Assumed Common Shares (MM)	662	664	658	

(1) Illustrative only – assumes 5% EPS growth

(2) See presentation appendix for factors used in reconciliation of earnings guidance to GAAP

(3) Assumes middle of the targeted payout range for 2005 and 2006 although no Board action has been taken

(4) Available for stock buyback although no Board action has been taken

Note: Items may not add due to rounding.

Conclusion

- Consistently strong financial results
- Balance Sheet strong and getting stronger
- Improving fundamentals
- Increasing available cash flow
- Positioned well for competitive markets

APPENDIX

Financial Overview

Reconciliation of Adjusted (non-GAAP) Operating Earnings Per Diluted Share to GAAP Earnings Per Diluted Share

Six Months Ended June 30, 2004 vs. Six Months Ended June 30, 2003

2003 GAAP Earnings per Diluted Share	**$**	**1.12**
2003 Adjusted (non-GAAP) Operating Earnings Adjustments:		
Impairment of Investment in Sithe Energies, Inc.		0.20
Cumulative Effect of Adopting SFAS No. 143		(0.17)
Impairment of InfraSource Goodwill		0.04
March 3 ComEd Settlement Agreement		0.03
2003 Adjusted (non-GAAP) Operating Earnings		**1.22**
2004 Adjusted (non-GAAP) Operating Earnings		**1.29**
2004 Adjusted (non-GAAP) Operating Earnings Adjustments:		
Cumulative Effect of Adopting FIN No. 46-R		0.05
Boston Generating, LLC 2004 Impact		0.04
Investments in Synthetic Fuel-Producing Facilities		0.04
Exelon Way Severance and Severance-Related Charges		(0.02)
2004 GAAP Earnings per Diluted Share	**$**	**1.40**

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

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**

Note: Reflects 2-for-1 stock split effective 5/5/04.

2004/2005 Earnings Guidance*

Exelon's adjusted (non-GAAP) operating earnings for 2004 are expected to be in the range of $2.75 to $2.90 per share and for 2005 in the range of $2.85 to $3.05 per share. Our outlook for adjusted (non-GAAP) operating earnings excludes income resulting from investments in synthetic fuel-producing facilities, the cumulative effect of adopting FIN 46-R, The Exelon Way severance, costs for accelerating the liability management program and any profit or loss related to Boston Generating. These estimates do not include any impact of future changes to GAAP.

* Reflects 2-for-1 stock split effective 5/5/04.

2003 Ramp-up Exelon Way Savings

Exelon

($ in millions)	2003 Pre-tax O&M Ramp-up Savings	
	2002	2003
GAAP Operating and Maintenance (O&M)	$ 4,345	$ 4,587
Operating Adjustments:		
March 2003 ComEd Settlement Agreement	—	(41)
Severance	(10)	(256)
Enterprises goodwill impairment and impairments due to anticipated sales	—	(53)
Operating O&M	**4,335**	**4,237**
Exelon Way O&M Adjustments:		
Remove Enterprises and Boston Generating (BG) (1)	(1,212)	(903)
Add incremental impact of Texas Plants	10	—
Remove nuclear decommissioning accretion expense (2)	—	(197)
Add 2002 incremental impact of Exelon New England	50	—
Normalize incremental impact of nuclear outages	(24)	—
Add AmerGen, net of decommissioning accretion (3)	412	393
Add Payroll Taxes (4)	95	91
Exelon Way O&M	**$ 3,666**	**$ 3,621**
Exelon Way O&M Savings:		
Difference between 2002 and 2003 Exelon Way O&M		$ 45
2003 inflationary impact (5)		107
Pension and post-retirement increase (6)		103
Calculated 2003 Savings		**$ 255**
Exclude savings from prior cost management initiatives (e.g., CMI)		(92)
Exelon Way O&M Savings — Pre-tax		**$ 163**
After-tax O&M Savings (7)		**$ 101**

	2003 Cap Ex Ramp-up Savings	
	2002	2003
GAAP Capital Expenditures (CapEx) (A)	**$ 2,150**	**$ 1,862**
Adjustments:		
Exclude net impact of Boston Generating (A)	—	20
Include AmerGen	155	171
Adjusted CapEx	**$ 2,305**	**$ 2,053**
Year-over-year CapEx Savings		**$ 252**
Exelon Way CapEx Savings:		
Difference between 2002 and 2003 Exelon Way CapEx		$ 252
2003 inflationary impact (B)		69
Calculated 2003 Savings		**$ 321**
Exclude savings from prior cost management initiatives (e.g., CMI)		(254)
Exelon Way Savings - 2003 Ramp-up		**$ 67**

(A) Net of proceeds from liquidated damages for 2003
(B) Inflation assumed at 3%

Total Ramp-up Cash Savings	
After-tax O&M	$ 101
CapEx	67
Total Exelon Way Cash Savings	**$ 168**

(1) O&M is net of intercompany impact and excludes corporate business services costs that remain; Enterprises excludes Exelon Energy

(2) Accretion expense is a non-cash expense related to nuclear decommissioning and is not included in Exelon Way expenditures

(3) Normalized to 100% of AmerGen in 2002 and 2003; in 2002 and 2003, AmerGen was included in Equity in Earnings of Unconsolidated Affiliates

(4) Includes AmerGen and excludes Enterprises

(5) 2002 base excluding pension and post-retirement expenses of $103m, inflated at 3%

(6) Pension and post-retirement expense increase

(7) Tax rate is 38%

June YTD Year-over-Year Exelon Way Savings

($ in millions)	Pre-tax O&M June YTD Savings 2004	Pre-tax O&M June YTD Savings 2003
GAAP Operating and Maintenance Expense (O&M)	**$ 2,165**	**$ 2,212**
Operating Adjustments:		
March 3 ComEd Global Settlement Agreement	—	(41)
Boston Generating (BG)	(57)	—
Investments in Synthetic Fuel Producing Facilities	(48)	—
Exelon Way Severance and Severance-related Charges	(22)	—
Impairment of Exelon Enterprises' InfraSource Investment	—	(48)
Operating O&M	**2,038**	**2,123**
Exelon Way O&M Adjustments:		
Remove Net Enterprises and BG (1)	(161)	(473)
Remove Nuclear Decommissioning Accretion Expense (2)	(127)	(117)
Remove 2004 Incremental Impact of Sithe	(23)	—
Add AmerGen, net of Accretion and Severance (3)	—	193
Normalize Incremental Impact of Nuclear Outages	(63)	—
Add Payroll Taxes (4)	54	56
Exelon Way O&M	**$ 1,718**	**$ 1,782**
Year-over-Year Exelon Way O&M Savings		**$ 64**

Program-to-Date O&M Savings	Pre-tax	After-tax (5)
2003 Ramp-up	$ 163	$ 101
2004 June YTD	64	40
Total Exelon Way O&M Savings	$ 227	$ 141

	CapEx June YTD Savings 2004	CapEx June YTD Savings 2003
GAAP Capital Expenditures (CapEx)	**$ 844**	**$ 1,019**
Adjustments:		
Include AmerGen CapEx	—	33
Exclude BG CapEx (incl. 2004 credit)	7	(80)
Adjusted CapEx	**$ 851**	**$ 972**
Year-over-Year CapEx Savings		**$ 121**
Program-to-Date Exelon Way CapEx Savings:		
2003 Ramp-up		$ 67
2004 June YTD		121
Total Exelon Way CapEx Savings		**$ 188**
Total YTD Cash Savings thru June 2004		
After-tax O&M		$ 40
CapEx		121
Total Exelon Way Cash Savings		**$ 161**
Total Program-to-Date Cash Savings		
After-tax O&M		$ 141
CapEx		188
Total Exelon Way Cash Savings		**$ 329**

(1) O&M is net of intercompany impact and excludes corporate business services costs that remain. Enterprises excludes Exelon Energy in 2003; in 2004 Exelon Energy is included in Generation.

(2) Accretion expense is a non-cash expense related to nuclear decommissioning and is not included in Exelon Way expenditures

(3) Normalize to 100% in 2003; in 2003, AmerGen was included in Equity in Earnings of Unconsolidated Affiliates

(4) Includes AmerGen and excludes Enterprises

(5) Tax rate is 38%

Free Cash Flow

We define free cash flow as:

- Cash from operations (which includes pension contributions and the benefit of synthetic fuels investment), less
- Cash used in investing activities, less
  - Transition debt maturities
  - Common stock dividend payments at 2003 rates
  - Other routine activities (e.g., severance payments, tax effect of discretionary items, etc.)
- Plus cash from asset dispositions, etc.

Available Cash Flow

- Cash from operations less capital expenditures, less common stock dividend payments at January 2004 level

June 2004 Year-to-Date Reconciliation

Total Increase in Cash and Cash Equivalents to Free Cash Flow Reconciliation

Increase in Cash and Cash Equivalents	$	301
Adjustments for Goal:		
Discretionary Debt Activity:		
- Change in Short-Term Debt		65
- Net Long-Term Debt Retirements(1)		264
- Other Financing Activities		(36)
Net Cash from Long-Term Incentive Plan(2)		(65)
Other Discretionary Adjustments(3)		59
Total Adjustments		287
Free Cash Flow	$	588

(1) Includes net long-term debt issuances and payment on the acquisition note to Sithe Energies, Inc. and excludes ComEd Transitional Funding Trust and PECO Energy Transition Trust Retirements.

(2) Includes the proceeds from employee stock plans net of cash paid to purchase treasury shares.

(3) Includes the incremental increase in dividend payments over 2003, exclusion of Sithe cash, severance payments and the tax effect of discretionary items.

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
Preferred Securities of Subsidiaries
Adjusted Book Debt

Total Adjusted Capitalization

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

Strategic Overview / Q&A

John W. Rowe
Chairman & Chief Executive Officer

Exelon Investor Conference
New York City
August 19, 2004

Exelon Is Leading The Way in Uncertain Times...

- Supplying Low Cost, Low Emissions Generation
- Ensuring Dependable Service with Increasingly Competitive Rates
- Promoting Competitive Markets
- Benefiting from Rising Wholesale Prices
- Strengthening Our Balance Sheet
- Delivering Outstanding Financial Performance

. . . and Building Exceptional Value for our Shareholders

Additional Information

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	2009, 2011	License renewal application filed 1/03
LaSalle	2	2,288	2022, 2023	
Limerick	2	2,309	2024, 2029	
Oyster Creek	1	625	2009	Intend to file for license renewal in 2005
Peach Bottom	2	2,262	2033, 2034	License renewal approved by NRC 5/03
Quad Cities	2	1,742	2012	License renewal application filed 1/03
TMI-1	1	837	2014	License renewal decision under review
Total	17	17,534		

* Shown at 100% of capacity

Midwest Generation PPA Options

In 2002, we released 4,411 MWs of options; in 2003, we had 3,043 MWs of options to exercise or release for 2004. We released 578 MWs on 6/24/03 and 303 MWs on 10/1/03.

	Coal PPA (MWs)		Collins PPA (MWs)	Peakers PPA (MWs)	Total (MWs)
	Non-option	**Option**			
2002 Capacity	**5,645**		**2,698**	**808**	**9,151**
2002 Decision	1,696	3,949	Released 1,614	Released 113	Released 4,411
	Released 2,684				
2003 Capacity	**2,961**		**1,084**	**695**	**4,740**
2003 Decision	1,696	1,265	Released none	Released 303	Released 881
	Released 578				
2004 Capacity	**2,383**		**1,084**	**392**	**3,859**

Note: All Midwest Gen contracts expire after 2004.

PECO ENERGY

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

(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)

Annual Stranded Cost Amortization and Return[a]

Year	Annual Sales	CTC	Revenue, excluding Gross Receipts Tax		
			Total	Return @ 10.75%	Amortization
	MWh	¢/kWh	($000)	($000)	($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 Ratemaking Return on Equity

For illustrative purposes consistent with how PECO currently reports to the PA Public Utility Commission. Stranded asset recovery is considered part of regulated operations and is therefore filed on a combined basis. Data presented here reflects total utility operations, including stranded asset recovery, electric distribution and transmission and gas operations.

For the Year Ended December 31, 2003

($ in millions)

Net Income on Common Stock	468
Ratemaking Common Equity	4,901
ROE	9.5%

Capitalization Structure as of December 31, 2003

($ in millions)

	As Filed 10-K	Remove Transition Bonds	Adjusted Capitalization	Add back Parent Co. Receivable	Ratemaking Structure	Add Pro forma Trans. Bond Capital	Adjusted Ratemaking Capital
Debt	5,392	-3,849	1,543		1,543	1,420	2,963
Preferred	87		87		87	80	167
Common	929		929	1,623	2,552	2,349	4,901
Total Cap	6,408	-3,849	2,559	1,623	4,182	3,849	8,031

Note: The pro forma Transition Bond Capital is an adjustment that adds back capital equal to the transition bonds in the ratemaking structure mix of capital. It effectively undoes the securitization for ratemaking purposes. The $8 billion pro forma capitalization is approximately equal to rate base.

ComEd Restructuring Legislation

Enacted Dec. 1997

Rate Reductions

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

Direct Access Phase-In Schedule

- Residential
  5/1/2002 100% of residential customers have supplier choice.
- Commercial and Industrial, 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 recognize, 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); accelerate depreciation or amortization or 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 CTC Calculation

Bundled Base Rate	Average rate by customer class, frozen through 2006 per 1997 Illinois legislation
DST Rate	Average rate for distribution and transmission services per published tariff
Mitigation Factor	Guaranteed savings for customers, currently the greater of 10% of the bundled rate or $0.005/kWh
MVEC	Market value energy component adjusted annually on June 1
CTC	Competitive transition charge for recovery of investments made prior to restructuring

100-400 kW Avg. Demand	**Cents/kWh**		
Bundled Rate	7.428		
– DST Rate	1.577	→	Per published tariff by demand class
– Mitigation	0.743	→	Per 1997 Illinois legislation
– MVEC	3.788	→	Avg. 12-month forward energy prices of trade and bid/ask data from 12/26/03-1/23/04
= CTC	**1.320**		

ComEd MVEC – How It Works

Changes in MVEC and Mitigation Factor cause inverse changes to CTC:

(100-400 kW avg. demand; cents/kWh)

	June 2002	March 2003	June 2003	March 2004	Jun-Dec 2004	Jan 2005	Jan-May 2005
Bundled	7.428	Energy Prices	7.428	Energy Prices	7.428	Mitigation Factor	7.428
DST	1.368		1.520		1.577	↘	1.577
Mitigation	0.594	↗	0.743	↘	0.743		0.817
MVEC	2.660		3.933		3.788		3.788
CTC	2.806		1.232		1.320		1.246

Customer Impact

- Switching (retail electric suppliers (RES) only) as a percent of total 2003 GWh:
  - Small C&I – 19%
  - Large C&I – 49%
  - Total – 20%
- On January 1, 2005, the mitigation factor for C&I customers increases to the greater of $0.006/kWh or 11% of the bundled rate ($0.817/kWh), which decreases the CTC by the same amount.

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

Commonwealth Edison Company May 28, 2004

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 2004 — May 2005)

(All units are in cents per kilowatt-hour)

	Base Rate Revenue (1) (2)	**Delivery Service Revenue (3)**	**Market Value (4)**	**2004 Mitigation Amount (5)**
	(A)	**(B)**	**(C)**	**(D)**
Customer Transition Charge Customer Class				
Residential Delivery Service Customers				
Single Family Without Space Heat	8.715	3.372	3.890	0.610
Multi Family Without Space Heat	8.961	4.448	4.023	0.627
Single Family With Space Heat	5.836	2.335	3.598	0.409
Multi Family With Space Heat	6.169	2.896	3.649	0.432
Fixture-included Lighting Residential Delivery Service Customers	8.655	9.905	2.809	0.606

[Additional columns below]

[Continued from above table, first column(s) repeated]

	June 2004 — December 31, 2004 CTC	**2005 Mitigation Amount (6)**	**January 1, 2005 — May 2005 CTC**
	(E) = (A) - (B) - (C) - (D)	**(F)**	**(G) = (A) - (B) - (C) - (F)**
Customer Transition Charge Customer Class			
Residential Delivery Service Customers			
Single Family Without Space Heat	**0.843**	0.697	**0.756**
Multi Family Without Space Heat	**0.000**	0.717	**0.000**
Single Family With Space Heat	**0.000**	0.467	**0.000**
Multi Family With Space Heat	**0.000**	0.494	**0.000**
Fixture-included Lighting Residential Delivery Service Customers	**0.000**	0.692	**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 7% of the base rate revenue for the calendar year 2004.

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

Commonwealth Edison Company May 28, 2004

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 2004 — May 2005)

(All units are in cents per kilowatt-hour)

	Base Rate Revenue (1) (2)	**Delivery Service Revenue (1) (3)**	**Market Value (4)**	**2004 Mitigation Amount (5)**
	(A)	**(B)**	**(C)**	**(D)**
Customer Transition Charge Customer Class				
Nonresidential Delivery Service Customers				
With Only Watt-hour Only Meters	11.258	3.787	3.934	1.126
0 kW to and including 25 kW Demand	9.288	2.202	3.832	0.929
Over 25 kW to and including 100 kW Demand	8.344	1.958	3.826	0.834
Over 100 kW to and including 400 kW Demand	7.428	1.577	3.788	0.743
Fixture-included Lighting Nonresidential Delivery Service Customers	13.554	9.905	2.788	1.355
Street Lighting Delivery Service Customers — Dusk to Dawn	3.852	1.954	2.777	0.500
Street Lighting Delivery Service Customers — All Other Lighting	7.172	1.923	3.381	0.717
Railroad Delivery Service Customers (9)				
Pumping Delivery Service Customers	6.465	1.523	3.514	0.647

[Additional columns below]

[Continued from above table, first column(s) repeated]

	June 2004 — December 31, 2004 CTC (6) (7)	**2005 Mitigation Amount (8)**	**January 1, 2005 — May 2005 CTC (6,7)**
	(E) = (A) - (B) - (C) - (D)	**(F)**	**(G) = (A) - (B) - (C) - (F)**
Customer Transition Charge Customer Class			
Nonresidential Delivery Service Customers			
With Only Watt-hour Only Meters	**2.411**	1.238	**2.299**
0 kW to and including 25 kW Demand	**2.325**	1.022	**2.232**
Over 25 kW to and including 100 kW Demand	**1.726**	0.918	**1.642**
Over 100 kW to and including 400 kW Demand	**1.320**	0.817	**1.246**
Fixture-included Lighting Nonresidential Delivery Service Customers	**0.000**	1.491	**0.000**
Street Lighting Delivery Service Customers — Dusk to Dawn	**0.000**	0.600	**0.000**
Street Lighting Delivery Service Customers — All Other Lighting	**1.151**	0.789	**1.079**
Railroad Delivery Service Customers (9)			
Pumping Delivery Service Customers	**0.781**	0.711	**0.717**

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 0.5 cents per kilowatt-hour or 10% of the base rate revenue for the calendar year 2004.

(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).

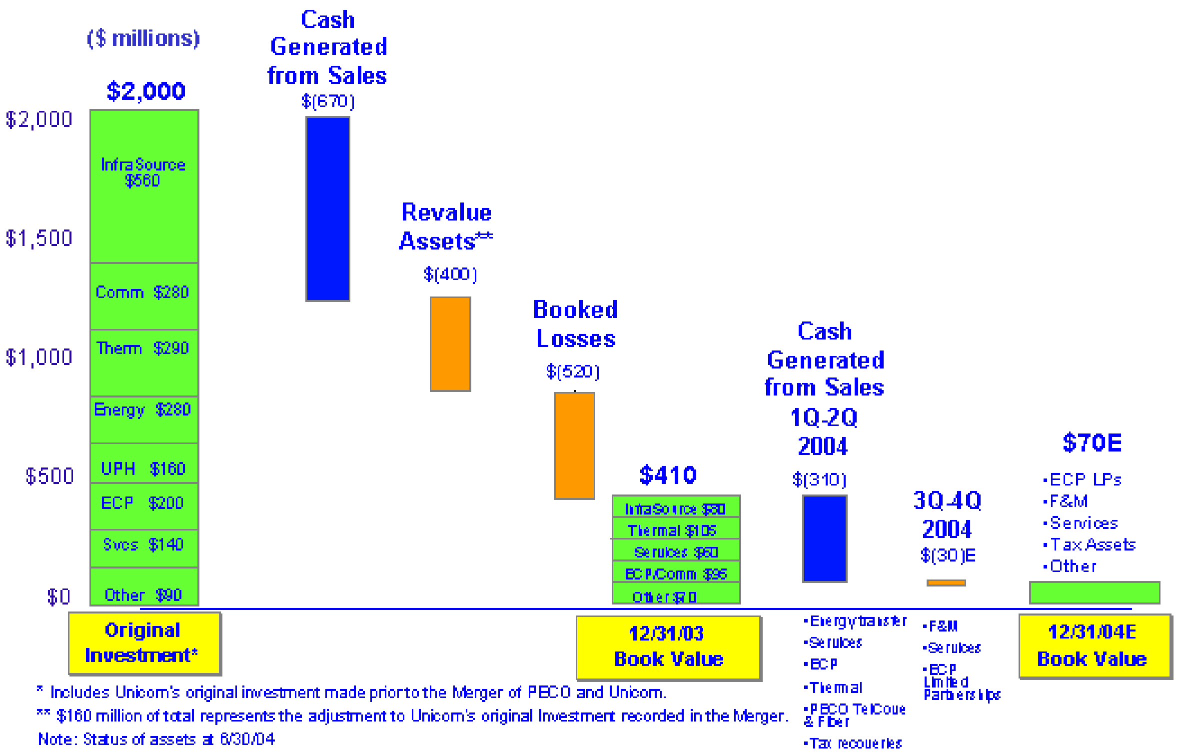
(7) CTCs are subject to change without specific notice if one of the components used in the determination of the CTC, as described in Rate CTC, is modified. If the CTC is equal to zero, this account will not be eligible for service under Rider PPO — Power Purchase Option (Market Index)

(Rider PPO).

(8) The mitigation amount as defined in Rate CTC is the greater of 0.6 cents per kilowatt-hour or 11% 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.

Revaluation of Enterprises' Assets



* Includes Unicom's original investment made prior to the Merger of PECO and Unicom.

** $160 million of total represents the adjustment to Unicom's original Investment recorded in the Merger.

Note: Status of assets at 6/30/04

E = Estimate

Enterprises – Path to Exit 2004 Update

Business Unit	**Agreement Signed**	**Transaction Close Date**
Exelon Services		
ESMG (Chicago)	Q1, 04	Q1, 04
Metropolitan (Minneapolis)	Q1, 04	Q1, 04
Reliance (Cleveland)	Q1, 04	Q1, 04
Wenninger (Milwaukee) - Fire Protection Business - Service Business - Construction Business ***	 Q2, 04 Q2, 04 N/A	 Q2, 04 Q2, 04 Q4, 04E
ITG **	Q3, 04	Q3, 04
Rieck (Dayton) **	Q3, 04	Q3, 04
Bumler (Detroit) **	Q3, 04E	Q3, 04E
Solutions/Federal Group	Q2, 04	Q2, 04
Exelon Thermal		
Chicago & Midway	2003	Q2, 04
Aladdin **	2003	Q3, 04E
Windsor **	2003	Q3, 04E
Fischbach & Moore		
Boston/Transit ***	Q3, 04E	Q3, 04E
New Jersey ***	Q3, 04	Q3, 04
New York ***	Q2, 04	Q3, 04E
Philadelphia ***	2003	Q4, 04E
Washington, DC ***	2003	Q3, 04E
Exelon Capital Partners		
Direct Investments	Q2, 04	Q2, 04
Limited Partnerships*	Q3, 04E*	Q3, 04E*
PECO TelCove	Q2, 04	Q2, 04

* Exploring possible sale of Limited Partnerships in Q3 subject to management approval
** Assets held for sale
*** Assets held for disposal
E = Estimated date

August 2004

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

August 2004

Securities Ratings for Exelon and its Subsidiary Companies

	Securities	**Moody's Investors Service**	**Standard & Poors Corporation**	**Fitch Investors Service, Inc.**
Exelon	Senior unsecured debt	Baa2	BBB+	BBB+
	Commercial paper	P2	A2	F2
ComEd	Senior secured debt	A3	A-	A-
	Commercial paper	P2	A2	F2
PECO	Senior secured debt	A2	A-	A
	Commercial paper	P1	A2	F1
Generation	Senior unsecured debt	Baa1	A-	BBB+
	Commercial paper	P2	A2	F2

August 1, 2004