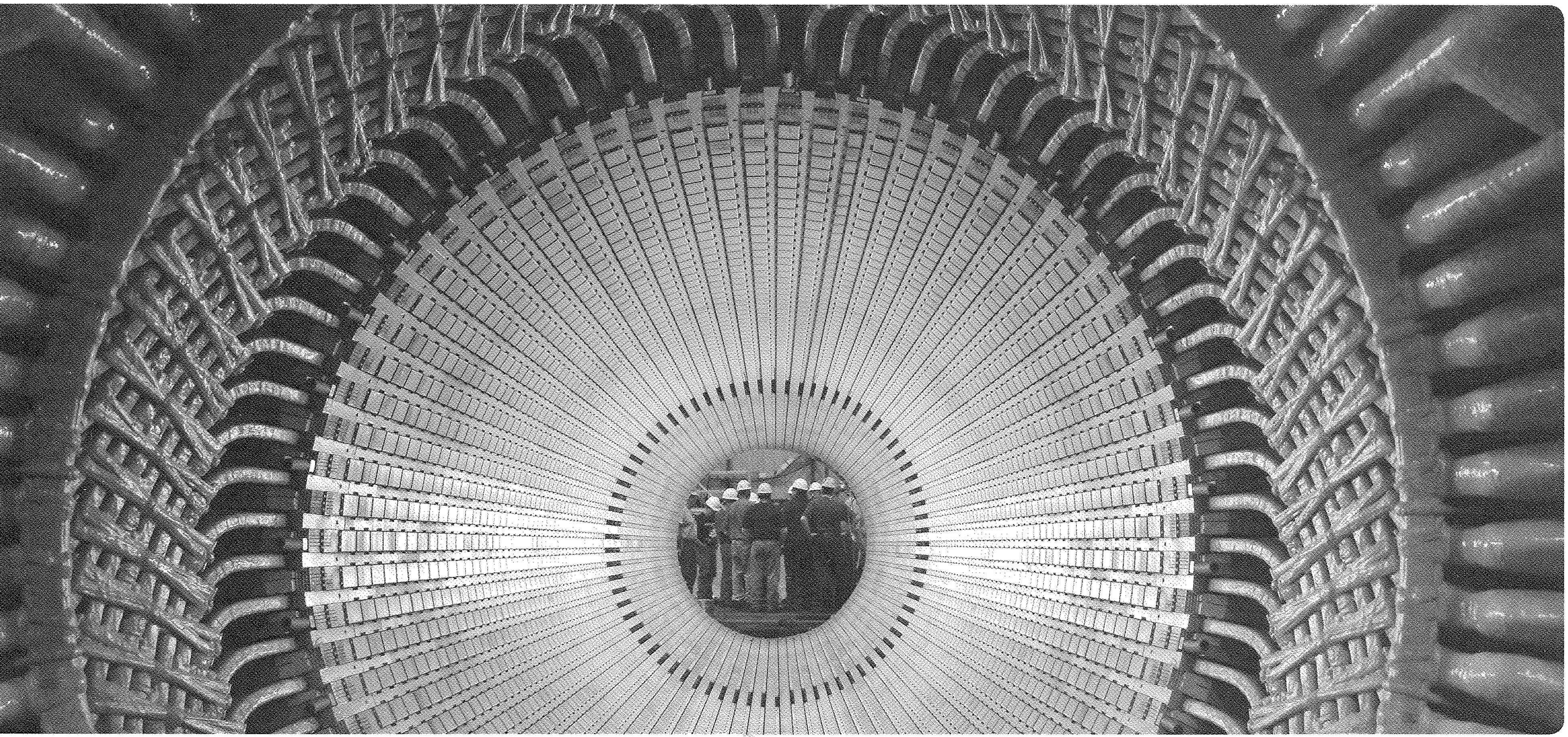
Smart Investment

Exelon Corporation 2010 Summary Annual Report

Exelon



On the cover: A view through the Quad Cities Unit 2 generator during that nuclear power station's low-pressure turbine replacement and refueling outage. This work at Quad Cities, along with improvements at Clinton, Dresden and LaSalle Generating Stations, led to 59 megawatts of clean electricity being added to the regional grid in 2010.

Adjusted (non-GAAP) operating earnings: This report includes a discussion of adjusted (non-GAAP) operating earnings. For a reconciliation of adjusted (non-GAAP) operating earnings to GAAP (accounting principles generally accepted in the United States), please see Exelon's fourth quarter earnings release issued on January 26, 2011, posted on the Investor Relations page at www.exeloncorp.com and included in the 8-K filed with the SEC on that date.

Forward-Looking Statements This report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from these forward-looking statements include those discussed herein as well as those discussed in (1) Exelon's 2010 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 18; and (2) other factors discusssed in Exelon's filings with the SEC. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this report. Exelon does not undertake any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this report.

Exelon is committed to building the nation's leading clean energy portfolio around our core of more than 17,000 megawatts of nuclear generation. We are pursuing this goal, guided by our annually updated Exelon 2020 plan, by increasing the capacity of our nuclear fleet, complying with Illinois and Pennsylvania renewable energy standards, purchasing John Deere's wind power company and conducting some of the largest energy efficiency programs in the nation.

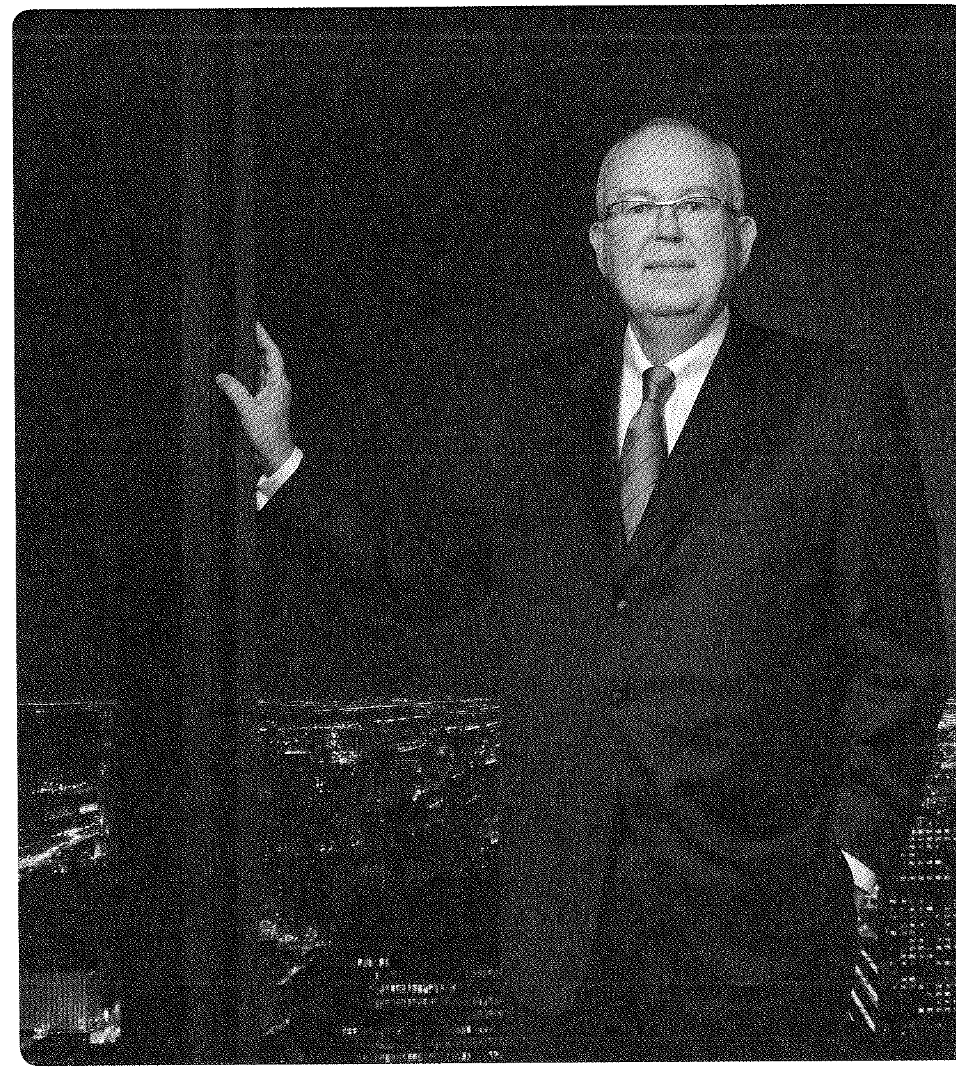
While the cap and trade-based carbon legislation that Exelon supported has failed, both political parties continue to pursue cleaner energy, each through its own favorite technologies and sometimes with little regard to the cost to consumers or public deficits. Exelon 2020 teaches us, and we hope others, that the kind and quantity of cleaner power we buy makes a big difference to consumers, taxpayers and utility shareholders. In times of economic stress, neither Exelon nor the nation can afford to ignore fundamental economics.

Exelon believes in and advocates for market-based solutions to energy supply issues. With U.S. EPA air quality regulations tightening and natural gas in plentiful supply, markets can guide us to efficient supplies of cleaner energy. Exelon will be at the table, protecting the electricity markets and seeking to capitalize on the nation's cleanest large-scale generation fleet.

John W. Rowe, Chairman and Chief Executive Officer

To Our Shareholders

In 2010 we witnessed the beginnings of an economic recovery, but electricity demand remained flat and electricity prices remained low. Nonetheless, Exelon delivered another strong year, with operating earnings of $2.7 billion. We are acting to protect and grow our future upside, and we are committed to enhancing your investment in difficult economic times as well as in the better ones that will follow.



John W. Rowe
Chairman and Chief Executive Officer

FINANCIAL PERFORMANCE

The Exelon team performed superbly despite the unfavorable market conditions that existed in 2010. Our GAAP earnings were $3.87 per diluted share, compared to $4.09 in 2009. On an adjusted (non-GAAP) basis, our operating earnings were $4.06 per diluted share, handily beating our original expectations, but lower than the $4.12 per diluted share that we earned in 2009. The difference was largely due to lower market prices for electricity, caused by low natural gas prices and reduced demand, and higher nuclear fuel costs. Those negative factors were offset to a large extent by increases in the capacity revenues we earned on our generating units as part of PJM.

> *"We delivered the highest average operating net income in the industry over the past three years and, as of the end of 2010, offered a 5 percent dividend yield."*

However, Exelon's share price on Dec. 31, 2010, was $41.64, down 14.8 percent from the year-end 2009 price of $48.87. Our stock performance frustrates me as much as it does you. Exelon's stock price is correlated to the forward prices of natural gas. Spot gas prices have dropped 70 percent, and forward prices 50 percent, since their peak in mid-2008. These natural gas prices along with electricity demand are the principal drivers of the wholesale market price of electricity, which in turn drives the earnings of our largest subsidiary, Exelon Generation. Demand for electricity is returning very slowly to pre-recession levels. Despite these market conditions, we delivered the highest average operating net income in the industry over the past three years and, as of the end of 2010, offered a 5 percent dividend yield, better than the 4.5 percent and 4.7 percent averages offered by our competitive integrated and regulated peers respectively. We retain more upside than either group from an increase in natural gas or power prices and the coming economic recovery. Since the merger that created Exelon, our total return – measured as stock price appreciation plus reinvested dividends – has been 97.5 percent. This compares to total returns of 73.1 percent and 9 percent for the Philadelphia Utility Index and S&P 500 respectively.

OPERATING PERFORMANCE

Our nuclear fleet continued to run at world-class levels with a capacity factor of 93.9 percent, the eighth consecutive year of capacity factors above 93 percent. The work and management focus that goes into delivering these consistent results is a clear competitive advantage for Exelon. At Exelon Power, the commercial availability of our fossil units was 95.3 percent and the hydro facilities performed at an equivalent availability factor of 96.8 percent for the year.

Power Team's financial results beat our expectations even with power prices in PJM down approximately 30 percent from 2008 levels. Our hedging program has again proven successful by allowing us to secure our earnings and cash flow and protect our investment-grade credit ratings. We realized average margins at Exelon Generation of $37.62 per megawatt-hour in 2010 despite lower power prices. Our hedges contributed to the $5.24 billion we generated in cash from operations across the businesses in 2010, and helped us to return $1.4 billion to our shareholders through dividends.

In the face of challenging weather, both ComEd and PECO kept the lights on and the gas flowing. In addition to high temperatures in the summer, ComEd faced 25 storms in 2010, including a storm on June 5 that produced seven tornadoes. ComEd's storm recovery team performed exceptionally well, restoring power to more than 1 million customers interrupted due to storms throughout June, with 90 percent of those customers restored within 24 hours of losing power. The weather was no better in Philadelphia: PECO successfully managed a highly volatile summer with extreme heat, damaging storms and high winds, including one storm that left more than 337,000 customers without power. We thank the management teams of both companies and their dedicated employees for these efforts.

"Our nuclear fleet continued to run at world-class levels with a capacity factor of 93.9 percent, the eighth consecutive year of capacity factors above 93 percent. The work and management focus that goes into delivering these consistent results is a clear competitive advantage for Exelon."

Chris Crane continues to lead Exelon's ongoing commitment to cost management, which kept our operating and maintenance expenses below 2008 levels. The Finance group took steps to increase our financial flexibility: early in 2011, we made a $2.1 billion contribution to the Exelon pension plans. This strengthens our balance sheet, improves our cash flow and reduces the size of future pension fund contributions. In addition, the Finance team closed a $1 billion credit facility for ComEd – the first of its size in the industry since the credit crisis – and executed $94 million in new credit agreements with minority and community banks that increased the company's business with local and diverse banks in our key markets. Exelon Business Services Company continued to provide best-in-class professional services, including legal, information technology, supply and human resources, adding great value to Exelon's operating companies.

SMART INVESTMENT FOR THE FUTURE

Roughly two-thirds of our business is commodity price-driven; the rest is regulated transmission and distribution. Because of that makeup, our business is part of a commodity cycle. While we are suffering through a period of depressed energy prices, no company in this industry is better able to benefit from the drive for clean energy and its eventual upside. As we wait for better prices, we work tirelessly to sustain our earnings and make smart investments in our companies.

In 2010, we continued to execute our multi-year nuclear uprate strategy, expanding the capacity of the fleet by 59 megawatts by making improvements at our Clinton, Dresden, LaSalle and Quad Cities stations. We have added a total of 101 megawatts since 2009. When this initiative is complete, we expect to have added as much as 1,500 megawatts of new generation, the equivalent of a new reactor at a much lower cost. In December, we completed the acquisition of John Deere Renewables – now Exelon Wind – adding 735 megawatts of clean generation to our fleet. Since the value is largely backed by sales contracts, this deal meets our dual objectives of securing a strategic position in the renewables business and enhancing shareholder value by investing in a disciplined manner.

We also took steps to capture value from the transmission system and prepare it for a clean energy future. ComEd is moving forward with transmission upgrades in the City of Chicago, which we expect to complete in 2011. Exelon Generation is taking steps to limit congestion around our units through projects like the transformer replacement at Clinton. And we are working with American Electric Power and Electric Transmission America, a joint venture of American Electric Power and MidAmerican Energy Holdings Company, for high-voltage transmission development across the Midwest to move renewable energy to where it is needed most.

"No company in this industry is better able to benefit from the drive for clean energy and its eventual upside. As we wait for better prices, we work tirelessly to sustain our earnings and make smart investments in our companies."

These investments position us favorably even without the climate legislation for which we advocated. The Environmental Protection Agency is working to issue rules under its existing statutory and court-ordered obligations under the Clean Air Act. These rules address criteria and hazardous pollutants such as sulfur dioxide and nitrogen oxide, mercury, hydrochloric acid, arsenic and other harmful gases. Exelon believes that these rules will enable the transition to a clean energy future without sacrificing the reliability of the electric power grid.

Exelon 2020, which is available on our website, serves as our resource plan, as a guide to our investment decisions and as a framework for our public policy advocacy. It tells us which actions provide our customers with reliable, clean energy at the lowest cost while also delivering the highest returns for our shareholders. It tells us which investments are economic and which investments are most costly. The Exelon 2020 business strategy cements Exelon's value as the premier low-emission company in the U.S. utility industry.

In sum, Exelon produced strong financial results for its shareholders in 2010 despite the challenges of the slow economic recovery and poor electricity market conditions. We served our customers and communities well. Exelon remains directed toward long-term success with our upside from economic and power market recovery, our continued healthy dividend yield and our strong balance sheet. These factors, along with our disciplined financial management and persistent hunt for investments, ensure that our company will provide enhanced value over the long-term.

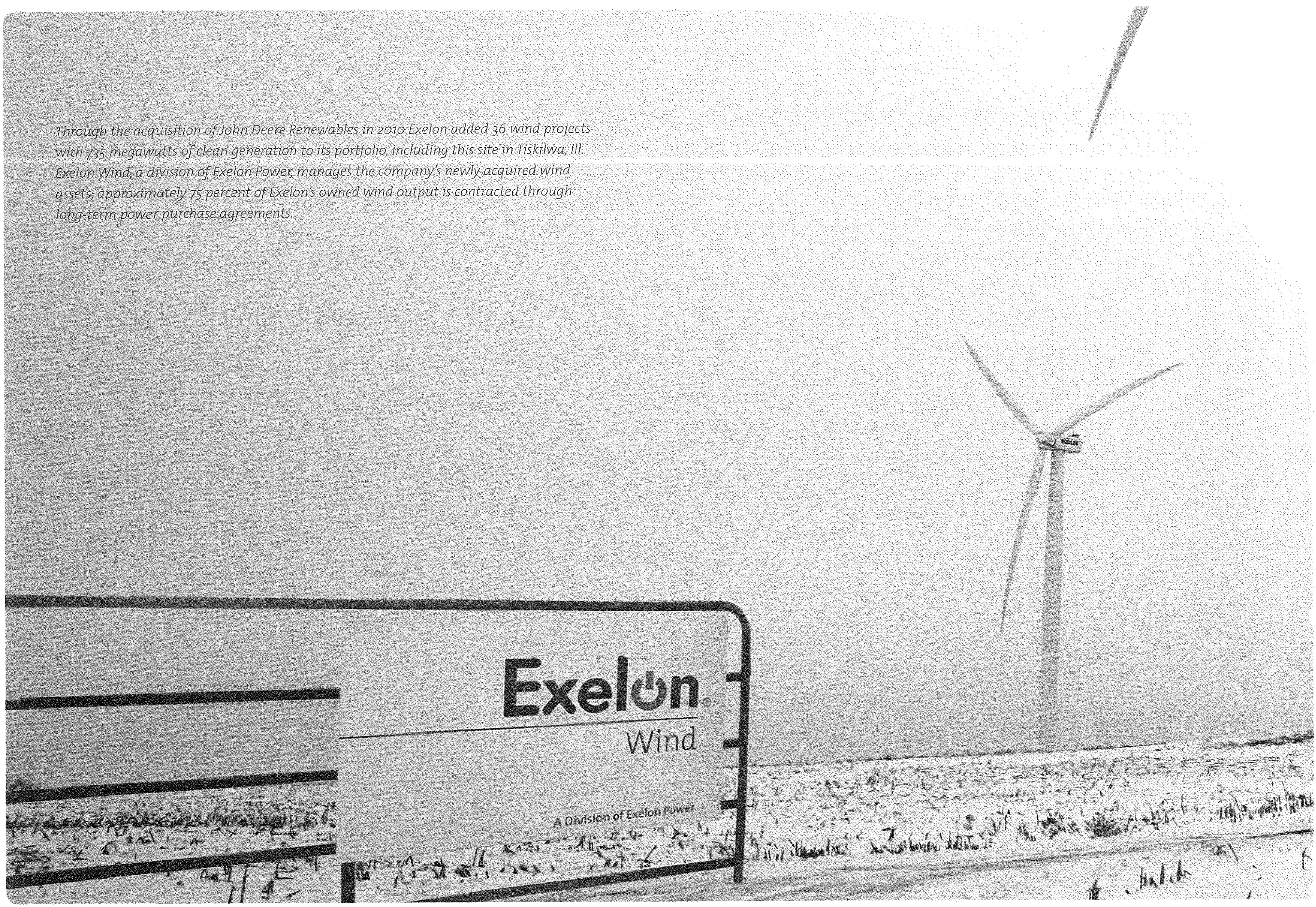
John W. Rowe

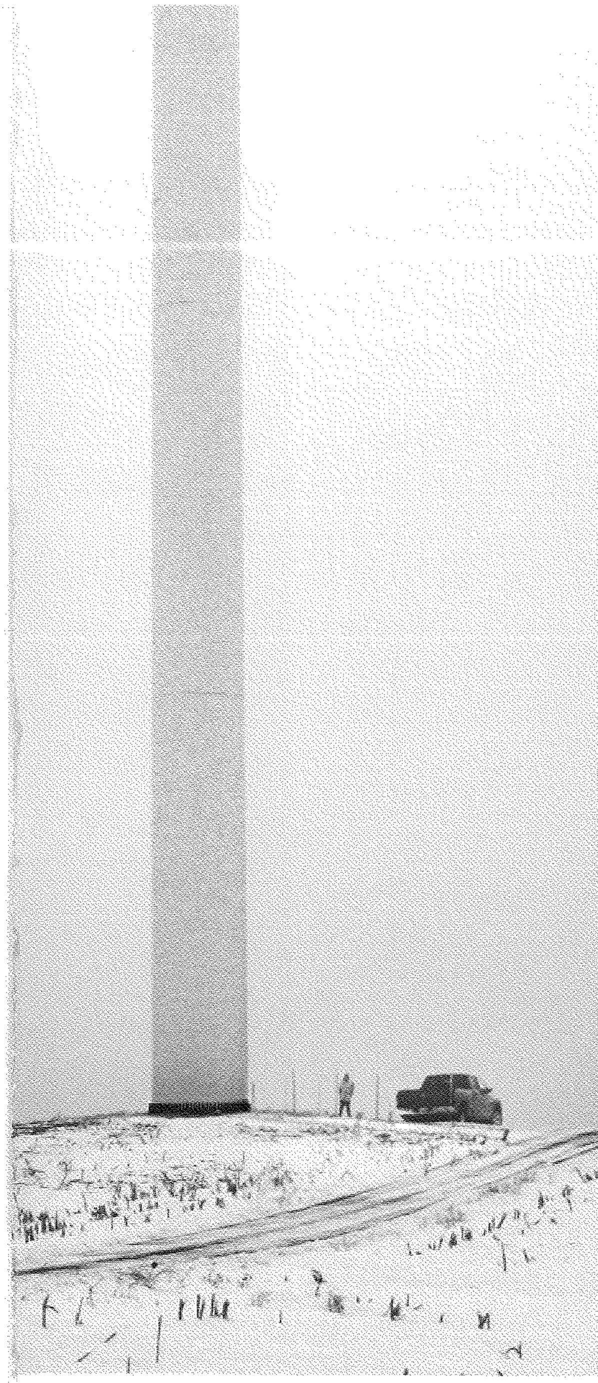
John W. Rowe

Chairman and Chief Executive Officer
Exelon Corporation

March 7, 2011

Through the acquisition of John Deere Renewables in 2010 Exelon added 36 wind projects with 735 megawatts of clean generation to its portfolio, including this site in Tiskilwa, Ill. Exelon Wind, a division of Exelon Power, manages the company's newly acquired wind assets; approximately 75 percent of Exelon's owned wind output is contracted through long-term power purchase agreements.





Our Vision:

Exelon will be the best group of electric generation and electric and gas delivery companies in the United States – providing superior value for our customers, employees, investors and the communities we serve.

our goals

> Keep the lights on and the gas flowing
> Run the nuclear fleet at world-class levels
> Capitalize on environmental leadership and clean nuclear energy
> Create a challenging and rewarding workplace
> Enhance the value of our generation
> Build value through disciplined financial management

our values

Safety – for our employees, our customers and our communities

Integrity – the highest ethical standards in what we say and what we do

Diversity – in ethnicity, gender, experience and thought

Respect – trust and teamwork through open and honest communication

Accountability – for our commitments, actions and results

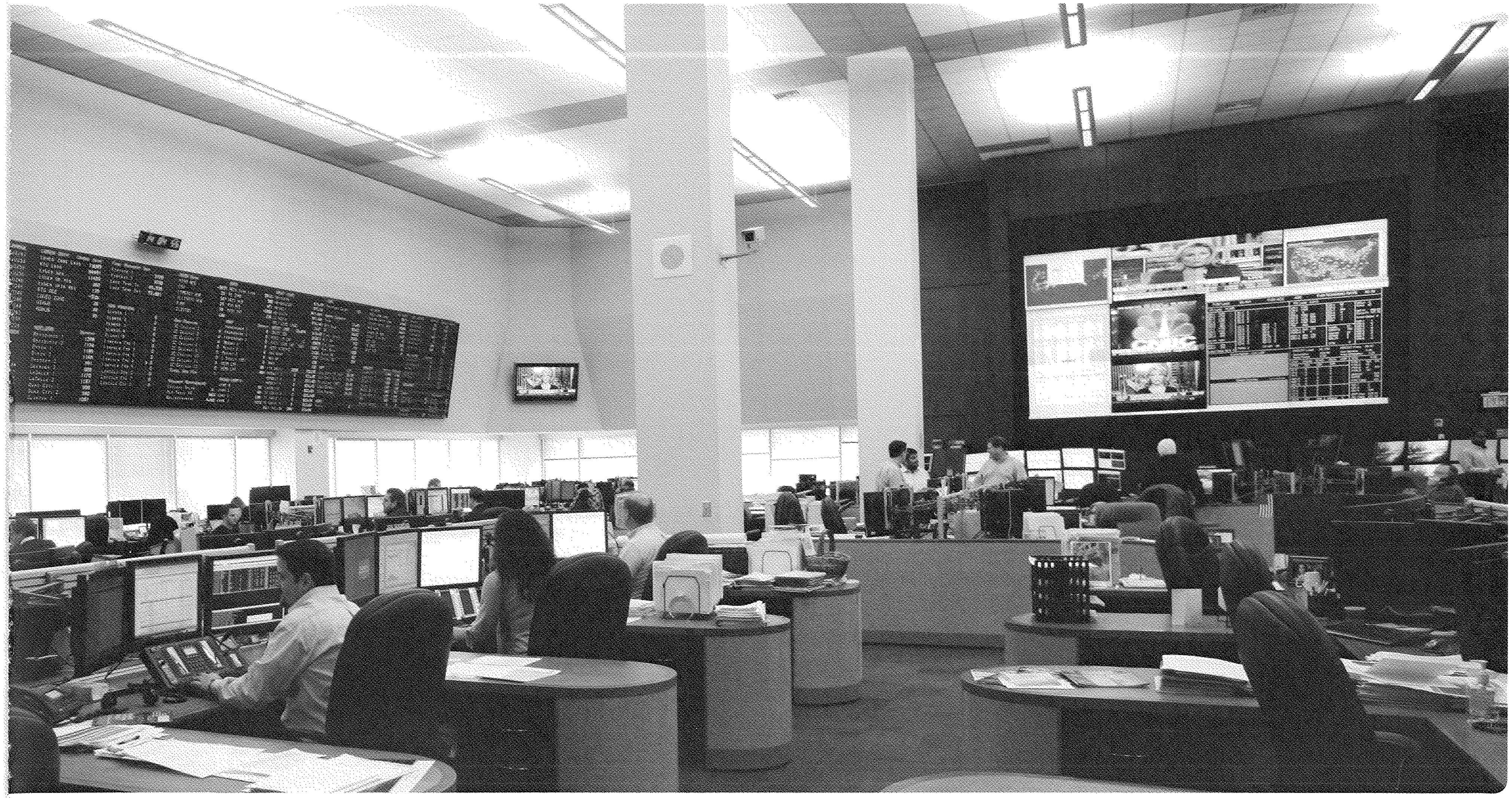
Continuous improvement – stretch goals and measured results

Financial Discipline

Maintaining our dividend, which yielded 5 percent at year-end, is a top priority, and in 2010 Exelon delivered approximately $1.4 billion in dividends to shareholders on the heels of strong earnings and free cash flow. Our success in generating favorable 2010 results can be credited to a number of factors: the hedging program managed so effectively by Power Team, favorable weather, our superior operating performance, prudent cost management and efficient use of capital.

Exelon's financial discipline and commitment to long-term shareholder value also are evident in several critical areas of our business. Our nuclear uprates program has already netted the company 101 additional megawatts of power from our existing nuclear fleet. This approach gives us new clean energy at a fraction of the cost of building a new nuclear plant.

In addition, our recent $2.1 billion contribution to our pension funds improves the company's overall financial flexibility through a period of low commodity and power prices, while increasing the assets to meet our pension obligations.



From the trade floor in Kennett Square, Pa., Power Team manages the interaction between the generation portfolio and the wholesale and retail markets in order to reduce risk, create opportunity and optimize the value of Exelon's generation.

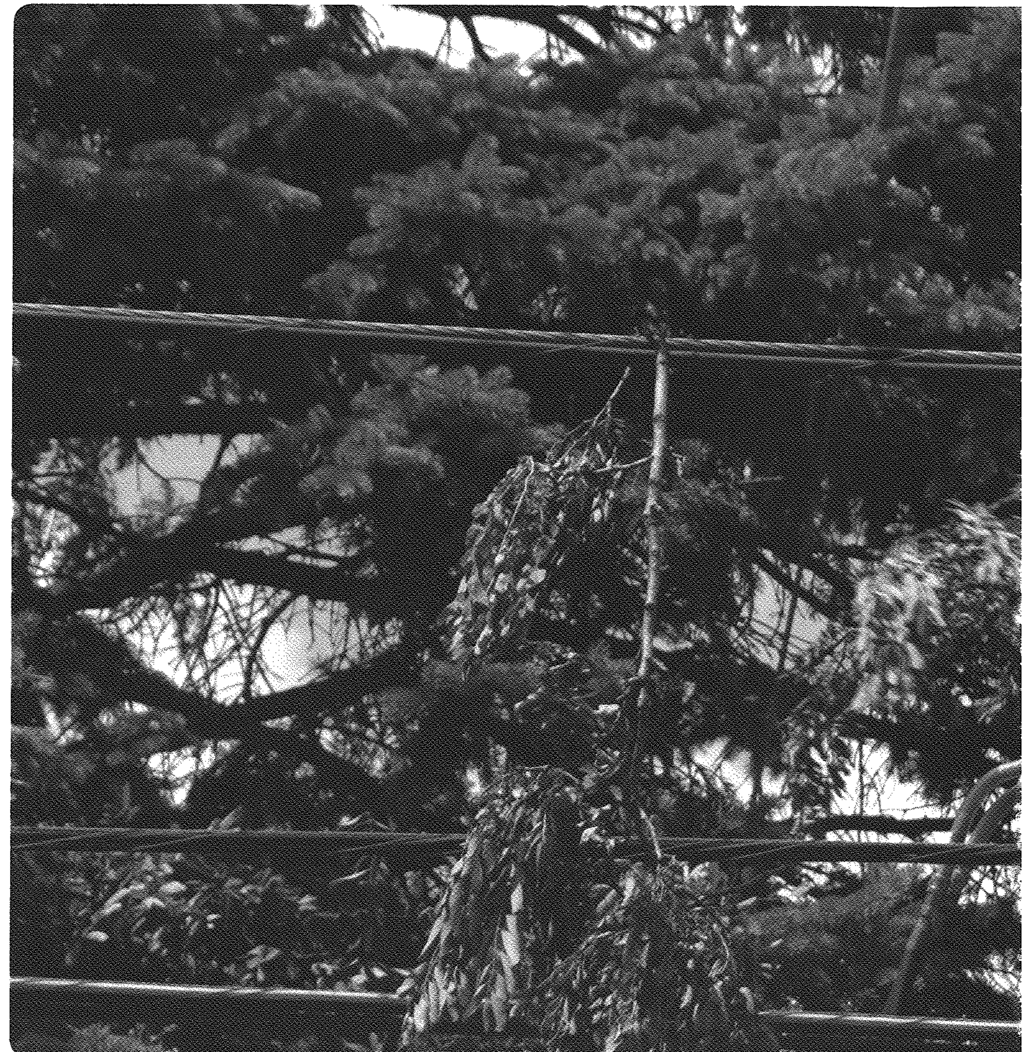
Operating Excellence

ComEd, PECO and Exelon Generation demonstrated their commitment to our customers through record-setting storm recovery efforts and successful refueling outages.

With our Chicago- and Philadelphia-area customers experiencing wind, rain and snow storms of unusual severity, our crews worked around the clock to restore power to hundreds of thousands of customers and replace thousands of poles and miles of wire safely and quickly. We are proud of their tireless efforts and teamwork and, most importantly, their commitment to safety.

On the generation side of the business, our nuclear fleet maintained a capacity factor of 93.9 percent in 2010 and completed nine refueling outages, including the replacement of three low-pressure turbines at Quad Cities Unit 2. Our fossil and renewable fleets also performed well, with a fossil plant commercial availability of 95.3 percent and an equivalent availability factor for the hydroelectric facilities of 96.8 percent.

Exelon Business Services Company provided world-class, cost-effective support to our operating companies, including the launch of *my*HR, which includes a website and service center that have dramatically improved human resources service levels for our employees and retirees while reducing costs.



Both ComEd and PECO kept the lights on and the gas flowing despite numerous severe storms throughout the year. This PECO line employee works to safely remove fallen branches from power lines after a summer storm.

Environmental Leadership

A clean energy portfolio based on sound economics creates compelling value. However, in the absence of a clear federal energy policy the United States is moving toward a lower-carbon, less-polluting society in uneconomic fits and starts. Selecting generation technology based on short-term perspectives does not benefit consumers and does not work for utilities. Pursuing the most economical options first offers the greatest benefit for our customers, shareholders and the economy – and that is why we are following this advice ourselves.

Exelon is now nearly three years into *Exelon 2020: a low-carbon roadmap*, our plan to reduce, offset or displace our company's 2001 carbon footprint. By following this business strategy, Exelon has achieved more than half of that goal, reducing more than 8 million metric tons of greenhouse gas emissions.

Through our acquisition of John Deere Renewables, which added 36 economic wind projects to Exelon's clean energy portfolio, our ongoing nuclear uprates program, customer energy efficiency efforts, 10 LEED-certified facilities and planned retirement of four fossil units, Exelon is proving that significant reductions in greenhouse gas emissions can be achieved without adverse effects on reliability or the economy.

Exelon Power's Handley Station is a natural gas-burning generating facility in Ft. Worth, Texas, with three units capable of generating 1,265 megawatts when needed. New natural gas discoveries promise a more abundant supply of this critical low-carbon fuel. The cheapest way to meet new demand for electricity – when that demand materializes – is currently natural gas combined-cycle units.

Talented Employees

None of the successes captured in this report, from our nuclear performance to the PECO rate cases described on page 19, would have been possible without our hard-working employees.

The work our employees do is complex and sometimes dangerous, and it is relied upon by millions of families and businesses in the regions where we operate. ComEd and PECO together cover more than 13,000 square miles and serve nearly 6 million electricity and gas customers – a tremendous responsibility that our people take very seriously.

For that reason, the safety of our employees and our customers is paramount. In 2010, we mourned the loss of our colleague Bill Boseo in a workplace accident. In honor of Bill and others we have lost over the years we constantly dedicate ourselves to safety in every work environment, from the plants and offices to warehouses and vehicles, with the goal of every employee returning home safely every day. We will continue to improve in this area, ever mindful that even one mishap is too many.

Beyond their successes within Exelon, our employees exhibit extraordinary leadership in our communities, volunteering nearly 66,000 hours in 2010, a 15 percent increase over 2009. We are proud of their efforts.

In helicopters and bucket trucks, at power plants and warehouses, at substations and in commercial locations, employees like this ComEd underground cable splicer perform tasks requiring skill, collaboration, excellence and a commitment to safety.

Exelon at a Glance

EXELON GENERATION

Exelon Nuclear's approximately 8,700 professionals operated its 17 nuclear reactors, the nation's largest commercial nuclear fleet, in a safe and reliable manner that helped position Exelon for long-term financial success.

In 2010, Exelon Nuclear was recognized for its commitment to safety with the 2010 National Safety Council Green Cross for Safety Award, the first time a utility has received the honor. In addition, Exelon Nuclear's plants achieved an average capacity factor of 93.9 percent in 2010, the eighth consecutive year capacity factor exceeded 93 percent, and produced just over 140 million megawatt-hours of electricity. Quad Cities Generating Station Unit 2 set a station continuous-run record of 446 days, while Peach Bottom Atomic Power Station's Unit 2 set its own record of 691 days.

Exelon Nuclear continued executing several important projects within its nuclear uprates program. Uprate projects take advantage of digital technology, new equipment and modern production techniques to add clean megawatts to a plant's output at cost and risk levels far lower than those associated with new plant construction. In 2010, uprates at Clinton, Dresden, LaSalle and Quad Cities Generating Stations led to 59 megawatts of clean electricity being added to the regional grid.

The company also announced its decision to retire Oyster Creek Generating Station by Dec. 31, 2019, instead of 2029. This decision was the result of a unique set of economic conditions and changing environmental regulations facing the plant that make ending operations in 2019 the best option for the company and its shareholders.

Exelon Power's fleet provided more than 10.7 million megawatt-hours of reliable generation in 2010 and achieved record performance levels in unit availability, delivering on the commitment of continuous improvement and performance optimization. Power performed at distinguished levels in 2010 on three key operational metrics: equivalent forced outage rate (demand), hydro equivalent availability and event-free clock resets.

Exelon Power furthered its role as an environmental leader in 2010. Successes included the awarding of LEED-Gold certification to the Conowingo Visitor Center in Maryland and the July 2010 dedication of Exelon City Solar, the nation's largest urban solar plant. City Solar is a 10-megawatt solar facility located on a former brownfield in the West Pullman neighborhood of Chicago.

In December, Exelon Power added 735 megawatts of wind generation to its portfolio through the acquisition of John Deere Renewables, which marked Exelon's entry into owning and operating wind projects. Exelon Wind, a division of Exelon Power, manages the company's wind operations.

Exelon Power's fleet now comprises 105 fossil (coal, oil and natural gas), landfill gas and hydroelectric units, 36 wind projects and a solar plant, located in 11 states and capable of generating more than 8,500 megawatts of electricity.

Exelon Power Team is the wholesale power marketing division of Exelon. Its role is to manage the risk and maximize the economic value associated with Exelon's electric generating facilities, power purchase agreements, fuel requirements, emissions credits, transmission contracts and load obligations. Power Team's wholesale marketing and transaction efforts are focused on the competitive electricity markets in many regions of the United States. The Power Team trade floor and headquarters are located in Kennett Square, Pa.

Exelon Energy is the retail marketing arm of Exelon. It markets electricity to customers in Illinois and Pennsylvania, and natural gas to customers in Illinois, Michigan and Ohio. Exelon Energy provides a valuable channel to market for Exelon's generation, while providing customers innovative products that can help them manage risk and gain the most from the competitive energy environment. Exelon Energy's locally based sales representatives have a wealth of experience in energy products and services and bring in-depth knowledge to the retail energy customers they serve.

COMED

ComEd had strong reliability performance in 2010, despite weathering the second-highest number of storm-related service interruptions in a decade, with a SAIFI (outage frequency) rate of 0.94 that was one of the best in ComEd's history. ComEd experienced a decline in safety performance in 2010 after posting best-on-record performance the previous year. While still solidly in the top quartile of industry performance, safety is a key focus area in 2011.

In response to continuing economic challenges, ComEd's Operational Strategy and Business Intelligence group collaborated with ComEd business units to offset cost increases through ongoing efficiency and productivity improvements.

ComEd moved forward with its smart meter pilot and smart grid "innovation corridor" technology study despite an Illinois Appellate Court ruling that struck down the company's mechanism for cost recovery. The company received Illinois Commerce Commission approval to recover some of these costs through a general rate case. The smart meter pilot is designed to assess how smart grid technology can enhance service, help customers make informed decisions about energy use and contribute to reduced carbon emissions.

ComEd's Smart Ideas℠ portfolio of energy efficiency programs exceeded second-year targets by 51 percent, helping customers achieve 472,132 megawatt-hours of energy savings – the equivalent of the energy required to power nearly 50,000 homes for one year.

In addition, ComEd restructured key business areas to improve system reliability and operational efficiency, and enhance customer service. Changes include a new regional reporting structure for Distribution Operations, an improved centralized structure for Transmission and Substation Operations and a new structure for Customer Operations to focus on long-term strategy, business transformation and revenue growth.

PECO

Despite one of the most active storm seasons in its history, PECO kept the lights on and the gas flowing for customers while establishing a new OSHA recordable safety record for the company. PECO also achieved a year-end ACSI (customer satisfaction) score of 73.2, the highest on record, and showed a 15-point improvement in the J.D. Power customer satisfaction study, moving the company to fourth place in overall satisfaction among large Eastern utilities.

PECO faced a year of significant change in 2010 with the expiration of generation rate caps, the transition to market-based pricing and state mandates to install advanced metering technology and conduct energy efficiency programs. The year proved successful, with the approval of simultaneous electric and gas rate cases and full launch of the award-winning PECO Smart Ideas℠ marketing campaign. The company successfully migrated customers to market-based pricing and instituted new electric and natural gas delivery rates, resulting in overall average price increases of 5.1 percent for residential electric customers and 1 percent for residential gas customers.

In 2010, PECO also reached a final funding agreement with the U.S. Department of Energy to advance the company's smart metering technology initiative as part of a $200 million federal stimulus grant award. PECO's $650 million project is being designed to improve local electric service reliability, build a platform for new technologies and energy-saving products, and promote renewable energy sources in support of Exelon 2020.

An active corporate citizen across the Greater Philadelphia region, PECO continued to drive forward its five-year, $15.3 million environmental initiative in 2010, resulting in LEED certification for five existing buildings, the awarding of $150,000 in PECO Green Region Grants to 23 local municipalities and ISO 14011 certification.

EXELON TRANSMISSION COMPANY

Exelon Transmission Company was established in October 2009 to capitalize on the growing national need for, and potential value of, new transmission capacity. Exelon Transmission Company harnesses the transmission strengths and capabilities of Exelon's generation and utility businesses, and creates partnerships with other utilities, transmission developers, renewable developers, regulators and others in creating the next generation of reliable electric transmission in the United States. Drawing on Exelon's deep experience, broad resources and strategic Illinois footprint, these transmission projects will improve reliability, reduce congestion and facilitate movement of low-carbon energy to markets where it is needed.

EXELON BUSINESS SERVICES COMPANY

Exelon Business Services Company (EBSC) is a direct, wholly-owned subsidiary of Exelon Corporation that provides quality products and services in a cost-effective manner to all Exelon companies.

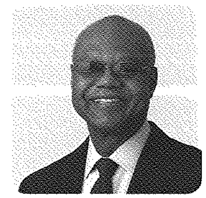
There are 12 EBSC practice areas: Audit and Controls, Commercial Operations Group (which includes accounts payable and payroll), Communications and Public Affairs, Corporate Strategy and Exelon 2020, Development, Finance, Government Affairs and Public Policy, Human Resources, Information Technology (which includes Cyber & Physical Security), Investments, Legal and Governance, and Supply.

In 2010, EBSC continued to focus on meeting service and cost commitments in the changing business climate in which the Exelon businesses operate. Of particular note was combining Information Technology Security and Corporate Security to allow better focus and tighter coordination on a nationally important issue that could potentially affect all of our operating companies.

Executive Committee

John W. Rowe
Chairman and Chief Executive Officer

Christopher M. Crane
President and Chief Operating Officer,
Exelon and President, Exelon Generation



Frank M. Clark
Chairman and Chief Executive Officer,
ComEd

Kenneth W. Cornew
Senior Vice President, Exelon
and President, Power Team

Joseph Dominguez
Senior Vice President, Federal Regulatory Affairs,
Public Policy and Communications, Exelon and
Senior Vice President, State Governmental Affairs,
Exelon Generation

Ruth Ann M. Gillis
Executive Vice President and Chief Administrative
and Diversity Officer, Exelon and President,
Exelon Business Services Company

Matthew F. Hilzinger
Senior Vice President, Chief Financial Officer
and Treasurer, Exelon

Denis P. O'Brien
Executive Vice President,
Exelon and President and CEO, PECO

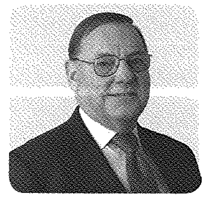
Anne R. Pramaggiore
President and Chief Operating Officer, ComEd

William A. Von Hoene Jr.
Executive Vice President,
Finance and Legal, Exelon

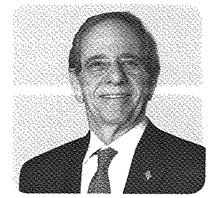
Former Executive Committee members Ian P. McLean, Elizabeth A. Moler and Andrea L. Zopp retired from the company in 2010.

Board of Directors

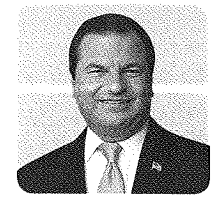
John W. Rowe
Chairman and Chief Executive Officer



John A. Canning Jr.
Chairman, Madison Dearborn Partners, LLC



M. Walter D'Alessio
Vice Chairman, NorthMarq Capital, Inc.



Nicholas DeBenedictis
Chairman, Chief Executive Officer and President
Aqua America, Inc.

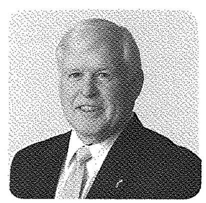
Bruce DeMars*
Admiral (Retired), United States Navy

Nelson A. Diaz
Of Counsel, Cozen O'Connor

Sue L. Gin
Chairman and Chief Executive Officer,
Flying Food Group, LLC

Rosemarie B. Greco
Principal, GRECOVentures
Former Senior Advisor to the Governor
of Pennsylvania, Health Care Reform

Paul L. Joskow
President, Alfred P. Sloan Foundation



Richard W. Mies
President and Chief Executive Officer
The Mies Group, Ltd.
Admiral (Retired), United States Navy

John M. Palms, Ph.D.
Distinguished President Emeritus,
University of South Carolina

William C. Richardson, Ph.D.
President and Chief Executive Officer Emeritus,
W. K. Kellogg Foundation

Thomas J. Ridge
Former Secretary, Department of
Homeland Security, Former Governor
of Pennsylvania

John W. Rogers Jr.
Chairman and Chief Executive Officer
Ariel Investments, LLC

Stephen D. Steinour
Chairman, President and
Chief Executive Officer,
Huntington Bancshares Incorporated

Don Thompson
President and Chief Operating Officer
McDonald's Corporation

Admiral DeMars retired from the Exelon board effective Dec. 31, 2010.

Financial Section

(Dollars in millions, except for per share data)	2010	2009	2008	2007	2006
					For the years ended Dec. 31,
Statement of operations data:					
Operating revenues	$ 18,644	$ 17,318	$ 18,859	$ 18,916	$ 15,655
Operating income	4,726	4,750	5,299	4,668	3,521
Income from continuing operations	2,563	2,707	2,717	2,726	1,590
Income from discontinued operations	–	–	20	10	2
Net income [(a)]	$ 2,563	$ 2,707	$ 2,737	$ 2,736	$ 1,592
Earnings per average common share (diluted):					
Income from continuing operations	$ 3.87	$ 4.09	$ 4.10	$ 4.03	$ 2.35
Income from discontinued operations	–	–	0.03	0.02	–
Net income	$ 3.87	$ 4.09	$ 4.13	$ 4.05	$ 2.35
Dividends per common share	$ 2.10	$ 2.10	$ 2.03	$ 1.76	$ 1.60
Average shares of common stock outstanding – diluted	663	662	662	676	676

(a) The year 2006 reflects the impact of a goodwill impairment charge of $776 million.

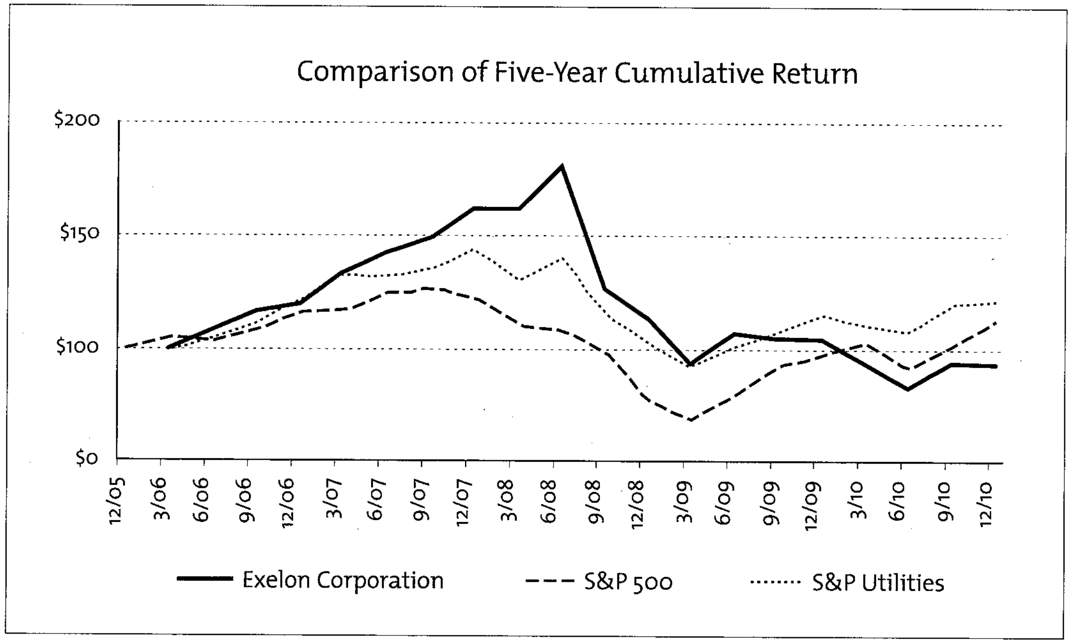
Summary of Earnings and Financial Condition

(Dollars in millions)	2010	2009	2008[a]	2007[a],[b]	2006[a],[b]
	For the years ended Dec. 31,				
Balance sheet data:					
Current assets	$ 6,398	$ 5,441	$ 5,130	$ 4,416	$ 4,130
Property, plant and equipment, net	29,941	27,341	25,813	24,153	22,775
Noncurrent regulatory assets	4,140	4,872	5,940	5,133	5,808
Goodwill	2,625	2,625	2,625	2,625	2,694
Other deferred debits and other assets	9,136	8,901	8,038	8,760	7,933
Total assets	$ 52,240	$ 49,180	$ 47,546	$ 45,087	$ 43,340
Current liabilities	$ 4,240	$ 4,238	$ 3,811	$ 5,466	$ 4,871
Long-term debt, including long-term debt to financing trusts	12,004	11,385	12,592	11,965	11,911
Noncurrent regulatory liabilities	3,555	3,492	2,520	3,301	3,025
Other deferred credits and other liabilities	18,791	17,338	17,489	14,131	13,439
Preferred securities of subsidiary	87	87	87	87	87
Noncontrolling interest	3	–	–	–	–
Shareholders' equity	13,560	12,640	11,047	10,137	10,007
Total liabilities and shareholders' equity	$ 52,240	$ 49,180	$ 47,546	$ 45,087	$ 43,340

(a) Exelon retrospectively reclassified certain assets and liabilities with respect to option premiums into the mark-to-market net asset and liability accounts to conform to the current-year presentation.
(b) Exelon retrospectively reclassified certain assets and liabilities in accordance with the applicable authoritative guidance for offsetting amounts related to qualifying derivative contracts.

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in Exelon common stock, as compared with the S&P 500 Stock Index and the S&P Utility Index for the period 2006 through 2010.

This performance chart assumes:
- $100 invested on Dec. 31, 2005, in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and
- All dividends are reinvested.



	Value of investment at Dec. 31, 2005	2006	2007	2008	2009	2010
Exelon Corporation	$ 100.00	$ 119.72	$ 161.70	$ 113.39	$ 104.02	$ 93.21
S&P 500	100.00	115.76	122.11	77.00	97.31	111.95
S&P Utilities	100.00	120.96	144.35	102.59	114.71	120.95

Source: Bloomberg

Results of Operations

(Dollars in millions, except for per share data)	2010	2009	Favorable (Unfavorable) Variance
Operating revenues	$ 18,644	$ 17,318	$ 1,326
Operating expenses			
Purchased power and fuel expense	6,435	5,281	(1,154)
Operating and maintenance	4,453	4,612	159
Operating and maintenance for regulatory required programs	147	63	(84)
Depreciation and amortization	2,075	1,834	(241)
Taxes other than income	808	778	(30)
Total operating expenses	13,918	12,568	(1,350)
Operating income	4,726	4,750	(24)
Other income and deductions			
Interest expense, net	(792)	(654)	(138)
Interest expense to affiliates, net	(25)	(77)	52
Loss in equity method investments	–	(27)	27
Other, net	312	427	(115)
Total other income and deductions	(505)	(331)	(174)
Income before income taxes	4,221	4,419	(198)
Income taxes	1,658	1,712	(54)
Net income	$ 2,563	$ 2,707	$ (144)
Diluted earnings per share	$ 3.87	$ 4.09	$ (0.22)

Exelon's net income was $2,563 million for the 12 months ended Dec. 31, 2010, as compared to $2,707 million for the 12 months ended Dec. 31, 2009, and diluted earnings per average common share were $3.87 for the 12 months ended Dec. 31, 2010, as compared to $4.09 for the 12 months ended Dec. 31, 2009. All amounts presented below are before the impact of income taxes, except as noted.

Exelon and its subsidiaries evaluate their operating performance using the measure of revenue net of purchased power and fuel expense. Exelon and its subsidiaries believe that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Revenue net of purchased power and fuel expense increased by $172 million primarily due to increased revenues of $201 million at Generation largely related to favorable capacity revenues, including under the Reliability Pricing Model, in the Midwest and Mid-Atlantic regions. Exelon's results were also affected by the impact of favorable weather conditions of $168 million in the ComEd and PECO service territories and a decrease in costs of $84 million associated with the Illinois Settlement Legislation, primarily at Generation. Further, revenues at the utility companies increased by $92 million to recover the costs of regulatory required programs, which are offset in operating expenses, and ComEd recognized recovery of $59 million from customers associated with its uncollectible accounts rider mechanism. Offsetting these favorable impacts were unfavorable market and portfolio conditions of $174 million, increased nuclear fuel costs of $115 million, a reduction of $95 million in mark-to-market gains from Generation's hedging activities in 2010 compared to 2009 and a $57 million impairment of SO2 emissions allowances related to the U.S. Environmental Protection Agency's proposed Transport Rule.

Operating and maintenance expense decreased by $75 million primarily due to the impact of 2009 activities, including the $223 million impairment of the Handley and Mountain Creek stations recorded in 2009 and reduced stock compensation costs in 2010 of $40 million across the operating companies. Decreased operating and maintenance expense was partially offset by higher costs at the utility companies associated with regulatory required programs of $84 million, a 2009 reduction in Generation's asset retirement obligation of $51 million and incremental costs of $42 million related to storms in the ComEd and PECO service territories. The costs of the utilities' regulatory required programs are offset in revenue net of purchased power and fuel expense.

Depreciation and amortization expense increased by $241 million primarily due to increased depreciation expense of $144 million related to ongoing capital expenditures and the change in estimated useful lives associated with the plants subject to shutdowns announced in December 2009 and increased scheduled amortization of competitive transition charges at PECO of $98 million, which were fully amortized as of Dec. 31, 2010, corresponding with the end of the transition period in accordance with PECO's 1998 restructuring settlement. Exelon's results were also significantly affected by $120 million in 2009 expenses related to debt extinguishment costs resulting from a 2009 debt refinancing, and by lower net nuclear decommissioning trust gains of $102 million in 2010 for Non-Regulatory Agreement Units as a result of less favorable market performance.

Exelon's results for the 12 months ended Dec. 31, 2010, were negatively affected by certain income tax-related matters. Exelon recorded a non-cash charge of $65 million (after tax) in 2010 and a non-cash gain of $66 million (after tax) in 2009 for the remeasurement of income tax uncertainties. Exelon also recorded a $65 million (after tax) charge to income tax expense as a result of health care legislation passed in March 2010, which includes a provision that reduces the deductibility of retiree prescription drug benefits for federal income tax purposes.

Results of Operations by Business Segment

The comparisons of 2010 and 2009 operating results and other statistical information set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Net Income (Loss) by Business Segment

(Dollars in millions)	2010	2009	Favorable (Unfavorable) 2010 vs. 2009 Variance
Generation	$ 1,972	$ 2,122	$ (150)
ComEd	337	374	(37)
PECO	324	353	(29)
Other [(a)]	(70)	(142)	72
Total	$ 2,563	$ 2,707	$ (144)

(a) Other primarily includes corporate operations, Exelon Business Service Company, LLC (EBSC) and intersegment eliminations.

Results of Operations – Generation

(Dollars in millions)	2010	2009	Favorable (Unfavorable) Variance
Operating revenues	$ 10,025	$ 9,703	$ 322
Purchased power and fuel expense	3,463	2,932	(531)
Revenue net of purchased power and fuel expense	6,562	6,771	(209)
Other operating expenses			
Operating and maintenance	2,812	2,938	126
Depreciation and amortization	474	333	(141)
Taxes other than income	230	205	(25)
Total other operating expenses	3,516	3,476	(40)
Operating income	3,046	3,295	(249)
Other income and deductions			
Interest expense	(153)	(113)	(40)
Loss in equity method investments	–	(3)	3
Other, net	257	376	(119)
Total other income and deductions	104	260	(156)
Income before income taxes	3,150	3,555	(405)
Income taxes	1,178	1,433	255
Net income	$ 1,972	$ 2,122	$ (150)

The decrease in Generation's net income was primarily due to decreased revenue net of purchased power and fuel expense as a result of lower margins realized on market and affiliate power sales primarily due to unfavorable market conditions, lower mark-to-market gains on economic hedging activities and increased nuclear fuel costs. These were partially offset by higher capacity revenues, including under the Reliability Pricing Model, in the Midwest and Mid-Atlantic regions, favorable settlements on the ComEd swap and decreased operating and maintenance expense.

The decrease in operating and maintenance expense was primarily due to the impact of the $223 million impairment of the Handley and Mountain Creek stations recorded in 2009. Lower operating and maintenance expense was partially offset by higher expense due to the absence of asset retirement obligation reductions that occurred in 2009; higher wages and benefits costs; and higher nuclear refueling outage costs in 2010. Additionally, Generation's earnings decreased due to lower net nuclear decommissioning trust gains for the Non-Regulatory Agreement Units in 2010 compared to 2009.

Results of Operations – ComEd

(Dollars in millions)	2010	2009	Favorable (Unfavorable) Variance
Operating revenues	$ 6,204	$ 5,774	$ 430
Purchased power expense	3,307	3,065	(242)
Revenue net of purchased power expense	2,897	2,709	188
Other operating expenses			
Operating and maintenance	975	1,028	53
Operating and maintenance for regulatory required programs	94	63	(31)
Depreciation and amortization	516	494	(22)
Taxes other than income	256	281	25
Total other operating expenses	1,841	1,866	25
Operating income	1,056	843	213
Other income and deductions			
Interest expense, net	(386)	(319)	(67)
Other, net	24	79	(55)
Total other income and deductions	(362)	(240)	(122)
Income before income taxes	694	603	91
Income taxes	357	229	(128)
Net income	$ 337	$ 374	$ (37)

The decrease in ComEd's net income was primarily due to the remeasurement of uncertain income tax positions in 2009 and 2010 related to the 1999 sale of ComEd's fossil generating assets. These remeasurements resulted in increased interest expense and income tax expense recorded in 2010, and increased interest income recorded in 2009. Net income was also reduced by higher incremental storm costs, increased depreciation and amortization expense reflecting higher plant balances, and the impact of federal health care legislation signed into law in March 2010. These reductions to net income were partially offset by higher revenue net of purchased power expense primarily due to favorable weather conditions, a net decrease in operating and maintenance expense, and the accrual of estimated future refunds of the Illinois utility distribution tax for the 2008 and 2009 tax years.

The decrease in operating and maintenance expense reflects the February 2010 approval by the Illinois Commerce Commission of ComEd's uncollectible accounts expense rider mechanism, the reduction of ComEd's asset retirement obligation in 2010, and a charge in 2009 for severance expense incurred as a cost to achieve savings under Exelon's 2009 company-wide cost savings initiative.

Results of Operations – PECO

(Dollars in millions)	2010	2009	Favorable (Unfavorable) Variance
Operating revenues	$ 5,519	$ 5,311	$ 208
Purchased power and fuel expense	2,762	2,746	(16)
Revenue net of purchased power and fuel expense	2,757	2,565	192
Other operating expenses			
Operating and maintenance	680	640	(40)
Operating and maintenance for regulatory required programs	53	–	(53)
Depreciation and amortization	1,060	952	(108)
Taxes other than income	303	276	(27)
Total other operating expenses	2,096	1,868	(228)
Operating income	661	697	(36)
Other income and deductions			
Interest expense, net	(193)	(187)	(6)
Loss in equity method investments	–	(24)	24
Other, net	8	13	(5)
Total other income and deductions	(185)	(198)	13
Income before income taxes	476	499	(23)
Income taxes	152	146	(6)
Net income	324	353	(29)
Preferred stock dividends	4	4	–
Net income on common stock	$ 320	$ 349	$ (29)

The decrease in PECO's net income was primarily driven by increased operating expense partially offset by increased electric revenues net of purchased power expense. The increase in operating expense reflected higher incremental storm costs and increased scheduled amortization of competitive transition charges. Electric revenues net of purchased power expense increased as a result of favorable weather conditions and increased competitive transition charge recoveries.

Consolidated Statements of Operations and Comprehensive Income

Exelon Corporation and Subsidiary Companies

(Dollars in millions, except for per share data)	For the years ended Dec. 31, 2010	2009	2008
Operating revenues	$ 18,644	$ 17,318	$ 18,859
Operating expenses			
Purchased power	4,425	3,215	4,270
Fuel	2,010	2,066	2,312
Operating and maintenance	4,453	4,612	4,538
Operating and maintenance for regulatory required programs	147	63	28
Depreciation and amortization	2,075	1,834	1,634
Taxes other than income	808	778	778
Total operating expenses	13,918	12,568	13,560
Operating income	4,726	4,750	5,299
Other income and deductions			
Interest expense, net	(792)	(654)	(699)
Interest expense to affiliates, net	(25)	(77)	(133)
Loss in equity method investments	–	(27)	(26)
Other, net	312	427	(407)
Total other income and deductions	(505)	(331)	(1,265)
Income from continuing operations before income taxes	4,221	4,419	4,034
Income taxes	1,658	1,712	1,317
Income from continuing operations	2,563	2,707	2,717
Discontinued operations			
Loss from discontinued operations, net of taxes of $0, $0 and $1, respectively	–	–	(1)
Gain on disposal of discontinued operations, net of taxes of $0, $0 and $14, respectively	–	–	21
Income from discontinued operations	–	–	20
Net income	$ 2,563	$ 2,707	$ 2,737

Consolidated Statements of Operations and Comprehensive Income

Exelon Corporation and Subsidiary Companies

(Dollars in millions, except for per share data)	For the years ended Dec. 31, 2010	2009	2008
Other comprehensive income (loss)			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic costs, net of taxes of $(7), $(6) and $(6), respectively	(11)	(13)	(9)
Actuarial loss reclassified to periodic cost, net of taxes of $79, $74 and $52, respectively	114	93	60
Transition obligation reclassified to periodic cost, net of taxes of $2, $2 and $2, respectively	3	3	3
Pension and non-pension postretirement benefit plan valuation adjustment, net of taxes of $(188), $47 and $(959), respectively	(288)	86	(1,459)
Change in unrealized gain (loss) on cash flow hedges, net of taxes of $(107), $(2) and $563, respectively	(151)	(12)	855
Change in unrealized gain (loss) on marketable securities, net of taxes of $0, $3 and $(6), respectively	(1)	5	(7)
Other comprehensive income (loss)	(334)	162	(557)
Comprehensive income	$ 2,229	$ 2,869	$ 2,180
Average shares of common stock outstanding:			
Basic	661	659	658
Diluted	663	662	662
Earnings per average common share – basic:			
Income from continuing operations	$ 3.88	$ 4.10	$ 4.13
Income from discontinued operations	–	–	0.03
Net income	$ 3.88	$ 4.10	$ 4.16
Earnings per average common share – diluted:			
Income from continuing operations	$ 3.87	$ 4.09	$ 4.10
Income from discontinued operations	–	–	0.03
Net income	$ 3.87	$ 4.09	$ 4.13
Dividends per common share	$ 2.10	$ 2.10	$ 2.03

The information in the Consolidated Statements of Operations and Comprehensive Income shown above is a replication of the information in the Consolidated Statements of Operations in Exelon's 2010 Form 10-K. For complete consolidated financial statements, including notes, please refer to pages 150 through 331 of Exelon's 2010 Form 10-K filed with the SEC. See also management's discussion and analysis of financial condition and results of operation, which includes a discussion of critical accounting policies and estimates, on pages 63 through 133 of Exelon's 2010 Form 10-K filed with the SEC.

Consolidated Statements of Cash Flows

Exelon Corporation and Subsidiary Companies

(Dollars in millions)	For the years ended Dec. 31, 2010	2009	2008
Cash flows from operating activities			
Net income	$ 2,563	$ 2,707	$ 2,737
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel amortization	2,943	2,601	2,308
Impairment of long-lived assets	–	223	–
Deferred income taxes and amortization of investment tax credits	981	756	374
Net fair value changes related to derivatives	(88)	(95)	(515)
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(105)	(207)	363
Other non-cash operating activities	609	652	870
Changes in assets and liabilities:			
Accounts receivable	(232)	234	67
Inventories	(62)	51	(109)
Accounts payable, accrued expenses and other current liabilities	472	(254)	(44)
Option premiums paid, net	(124)	(40)	(124)
Counterparty collateral received (posted), net	(155)	196	1,027
Income taxes	(543)	(29)	(38)
Pension and non-pension postretirement benefit contributions	(959)	(588)	(230)
Other assets and liabilities	(56)	(113)	(135)
Net cash flows provided by operating activities	5,244	6,094	6,551
Cash flows from investing activities			
Capital expenditures	(3,326)	(3,273)	(3,117)
Proceeds from nuclear decommissioning trust fund sales	3,764	4,292	10,657
Investment in nuclear decommissioning trust funds	(3,907)	(4,531)	(10,942)
Acquisition of Exelon Wind	(893)	–	–
Proceeds from sales of investments	28	41	–
Purchases of investments	(22)	(28)	–
Change in restricted cash	423	35	29
Other investing activities	39	6	(5)
Net cash flows used in investing activities	(3,894)	(3,458)	(3,378)

Consolidated Statements of Cash Flows

Exelon Corporation and Subsidiary Companies

(Dollars in millions)	For the years ended Dec. 31, 2010	2009	2008
Cash flows from financing activities			
Change in short-term debt	(155)	(56)	(405)
Issuance of long-term debt	1,398	1,987	2,265
Retirement of long-term debt	(828)	(1,773)	(1,398)
Retirement of long-term debt of variable interest entity	(806)	–	–
Retirement of long-term debt to financing affiliates	–	(709)	(1,038)
Dividends paid on common stock	(1,389)	(1,385)	(1,335)
Proceeds from employee stock plans	48	42	130
Purchase of treasury stock	–	–	(436)
Purchase of forward contract in relation to certain treasury stock	–	–	(64)
Other financing activities	(16)	(3)	68
Net cash flows used in financing activities	(1,748)	(1,897)	(2,213)
Increase (decrease) in cash and cash equivalents	(398)	739	960
Cash and cash equivalents at beginning of period	2,010	1,271	311
Cash and cash equivalents at end of period	$ 1,612	$ 2,010	$ 1,271

The information in the Consolidated Statements of Cash Flows shown above is a replication of the information in the Consolidated Statements of Cash Flows in Exelon's 2010 Form 10-K. For complete consolidated financial statements, including notes, please refer to pages 150 through 331 of Exelon's 2010 Form 10-K filed with the SEC. See also management's discussion and analysis of financial condition and results of operation, which includes a discussion of critical accounting policies and estimates, on pages 63 through 133 of Exelon's 2010 Form 10-K filed with the SEC.

Consolidated Balance Sheets

Exelon Corporation and Subsidiary Companies

(Dollars in millions)	For the years ended Dec. 31, 2010	2009
Assets		
Current assets		
Cash and cash equivalents	$ 1,612	$ 2,010
Restricted cash and investments	30	40
Accounts receivable, net		
Customer ($346 gross accounts receivable pledged as collateral as of Dec. 31, 2010)	1,932	1,563
Other	1,196	486
Mark-to-market derivative assets	487	376
Inventories, net		
Fossil fuel	216	198
Materials and supplies	590	559
Other	335	209
Total current assets	6,398	5,441
Property, plant and equipment, net	29,941	27,341
Deferred debits and other assets		
Regulatory assets	4,140	4,872
Nuclear decommissioning trust funds	6,408	6,669
Investments	717	704
Investments in affiliates	15	20
Goodwill	2,625	2,625
Mark-to-market derivative assets	409	649
Pledged assets for Zion Station decommissioning	824	–
Other	763	859
Total deferred debits and other assets	15,901	16,398
Total assets	$ 52,240	$ 49,180

Consolidated Balance Sheets

Exelon Corporation and Subsidiary Companies

(Dollars in millions)	For the years ended Dec. 31, 2010	2009
Liabilities and shareholders' equity		
Current liabilities		
Short-term borrowings	$ –	$ 155
Short-term notes payable—accounts receivable agreement	225	–
Long-term debt due within one year	599	639
Long-term debt to PECO Energy Transition Trust due within one year	–	415
Accounts payable	1,373	1,345
Mark-to-market derivative liabilities	38	198
Accrued expenses	1,040	923
Deferred income taxes	85	152
Other	880	411
Total current liabilities	4,240	4,238
Long-term debt	11,614	10,995
Long-term debt to other financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	6,621	5,750
Asset retirement obligations	3,494	3,434
Pension obligations	3,658	3,625
Non-pension postretirement benefit obligations	2,218	2,180
Spent nuclear fuel obligation	1,018	1,017
Regulatory liabilities	3,555	3,492
Mark-to-market derivative liabilities	21	23
Payable for Zion Station decommissioning	659	–
Other	1,102	1,309
Total deferred credits and other liabilities	22,346	20,830
Total liabilities	38,590	36,453
Commitments and contingencies		
Preferred securities of subsidiary	87	87
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 662 and 660 shares outstanding at Dec. 31, 2010, and Dec. 31, 2009, respectively)	9,006	8,923
Treasury stock, at cost (35 shares held at Dec. 31, 2010, and Dec. 31, 2009, respectively)	(2,327)	(2,328)
Retained earnings	9,304	8,134
Accumulated other comprehensive loss, net	(2,423)	(2,089)
Total shareholders' equity	13,560	12,640
Noncontrolling interest	3	–
Total equity	13,563	12,640
Total liabilities and shareholders' equity	$ 52,240	$ 49,180

The information in the Consolidated Balance Sheets shown above is a replication of the information in the Consolidated Balance Sheets in Exelon's 2010 Form 10-K. For complete consolidated financial statements, including notes, please refer to pages 150 through 331 of Exelon's 2010 Form 10-K filed with the SEC. See also management's discussion and analysis of financial condition and results of operation, which includes a discussion of critical accounting policies and estimates, on pages 63 through 133 of Exelon's 2010 Form 10-K filed with the SEC.

Consolidated Statements of Changes in Shareholders' Equity

Exelon Corporation and Subsidiary Companies

(Dollars in millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total Shareholders' Equity
Balance, Dec. 31, 2007	689,183	$ 8,579	$ (1,838)	$ 4,930	$ (1,534)	$ –	$ 10,137
Net income	–	–	–	2,737	–	–	2,737
Long-term incentive plan activity	3,452	217	–	–	–	–	217
Employee stock purchase plan issuances	318	19	–	–	–	–	19
Common stock purchases	–	1	(500)	–	–	–	(499)
Common stock dividends	–	–	–	(1,007)	–	–	(1,007)
Adoption of the fair value option for financial assets and liabilities, net of income taxes of $286	–	–	–	160	(160)	–	–
Other comprehensive loss, net of income taxes of $(290)	–	–	–	–	(557)	–	(557)
Balance, Dec. 31, 2008	692,953	$ 8,816	$ (2,338)	$ 6,820	$ (2,251)	$ –	$ 11,047
Net income	–	–	–	2,707	–	–	2,707
Long-term incentive plan activity	1,088	85	10	(5)	–	–	90
Employee stock purchase plan issuances	524	22	–	–	–	–	22
Common stock dividends	–	–	–	(1,388)	–	–	(1,388)
Other comprehensive income, net of income taxes of $119	–	–	–	–	162	–	162
Balance, Dec. 31, 2009	694,565	$ 8,923	$ (2,328)	$ 8,134	$ (2,089)	$ –	$ 12,640
Net income	–	–	–	2,563	–	–	2,563
Long-term incentive plan activity	1,380	60	1	(1)	–	–	60
Employee stock purchase plan issuances	644	23	–	–	–	–	23
Common stock dividends	–	–	–	(1,392)	–	–	(1,392)
Acquisition of Exelon Wind	–	–	–	–	–	3	3
Other comprehensive loss, net of income taxes of $(221)	–	–	–	–	(334)	–	(334)
Balance, Dec. 31, 2010	696,589	$ 9,006	$ (2,327)	$ 9,304	$ (2,423)	$ 3	$ 13,563

The information in the Consolidated Statements of Changes in Shareholders' Equity shown above is a replication of the information in the Consolidated Statements of Changes in Shareholders' Equity in Exelon's 2010 Form 10-K. For complete consolidated financial statements, including notes, please refer to pages 150 through 331 of Exelon's 2010 Form 10-K filed with the SEC. See also management's discussion and analysis of financial condition and results of operation, which includes a discussion of critical accounting policies and estimates, on pages 63 through 133 of Exelon's 2010 Form 10-K filed with the SEC.

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting. Exelon's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of Dec. 31, 2010. In making this assessment, management used the criteria in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of Dec. 31, 2010, Exelon's internal control over financial reporting was effective.

The effectiveness of the Company's internal control over financial reporting as of Dec. 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report.

Feb. 10, 2011

Information Derived from 2010 Form 10-K

We have presented a condensed discussion of financial results, excerpts from our consolidated financial statements and a copy of our Management's Report on Internal Control Over Financial Reporting in this summary annual report. A complete discussion of our financial results and our complete consolidated financial statements, including notes, appears on pages 63 through 331 of our Form 10-K annual report for the year ended Dec. 31, 2010. That annual report was filed with the Securities and Exchange Commission on Feb. 10, 2011, and can be viewed and retrieved through the Commission's website at www.sec.gov or our website at www.exeloncorp.com.

Our independent registered public accounting firm, PricewaterhouseCoopers LLP (PwC), issued a report dated Feb. 10, 2011, on its integrated audit of our consolidated financial statements and our internal controls over financial reporting. In its report PwC expressed an unqualified opinion that those consolidated financial statements present fairly, in all material respects, the financial position of Exelon Corporation and its subsidiaries at Dec. 31, 2010, and 2009 and the results of their operations and their cash flows for each of the three years in the period ended Dec. 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Furthermore, PwC expressed an unqualified opinion that Exelon maintained, in all material respects, effective internal control over financial reporting as of Dec. 31, 2010, based on criteria established in Internal Control – Integrated Framework issued by the COSO. The full text of PwC's report can be found on page 154 of our 2010 Form 10-K.

Corporate Profile

Exelon Corporation is one of the nation's largest electric utilities with more than $18 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 5.4 million customers in northern Illinois and southeastern Pennsylvania and natural gas to approximately 486,000 customers in the Philadelphia area. Exelon is headquartered in Chicago and trades on the NYSE under the ticker EXC.

Corporate Headquarters
Exelon Corporation
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Employee Stock Options
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Independent Public Accountants
PricewaterhouseCoopers LLP

Website
www.exeloncorp.com

Stock Ticker
EXC

Shareholder Inquiries

Exelon Corporation has appointed Wells Fargo Shareowner Services as its transfer agent, stock registrar, dividend disbursing agent and dividend reinvestment agent. Should you have questions concerning your registered shareholder account or the payment or reinvestment of your dividends, or if you wish to make a stock transaction or stock transfer, you may call shareowner services at Wells Fargo at the toll-free number shown to the left or access its website at www.shareowneronline.com.

Morgan Stanley Smith Barney administers the Employee Stock Purchase Plan (ESPP) and employee stock options. Should you have any questions concerning your employee plan shares or wish to make a transaction, you may call the toll-free numbers shown to the left or access its website at www.benefitaccess.com.

The Company had approximately 130,000 holders of record of its common stock as of Dec. 31, 2010.

The 2010 Form 10-K Annual Report to the Securities and Exchange Commission was filed on Feb. 10, 2011. To obtain a copy without charge, write to Bruce G. Wilson, Senior Vice President, Deputy General Counsel and Corporate Secretary, Exelon Corporation, Post Office Box 805379, Chicago, Illinois 60680-5379.

The Company maintains a telephone information service that enables investors to obtain currently available information on financial performance, company news and to access shareholder services at Wells Fargo. To use this service, please call our toll-free number: 866.530.8108.

The paper utilized for the printing of this report is certified to Forest Stewardship Council standards, which promotes environmentally appropriate, socially beneficial and economically viable management of the world's forests. All the paper utilized in the production of this annual report was manufactured by Mohawk Fine Papers and contains 30% post-consumer recycled fiber. Mohawk Fine Papers purchases enough Green-e certified renewable energy certificates (RECs) to match 100% of the electricity used in its operations. Mohawk has provided the calculations below on use of 33,000 pounds of paper.

The savings derived from using this paper in lieu of virgin fiber paper is equivalent to:

95 trees preserved for the future	**274 lbs.** waterborne waste not created	**40,372 gallons** wastewater flow saved	**4,467 lbs.** solid waste not generated	**8,795 lbs.** net greenhouse gases prevented	**67,320,000 BTUs** energy not consumed

The savings derived from choosing a paper manufactured using wind-generated electricity:

14,883 lbs. air emissions not generated	**16** barrels crude oil unused

This amount of wind-generated electricity is equivalent to:

1 car off the road for one year	**1,012** trees planted

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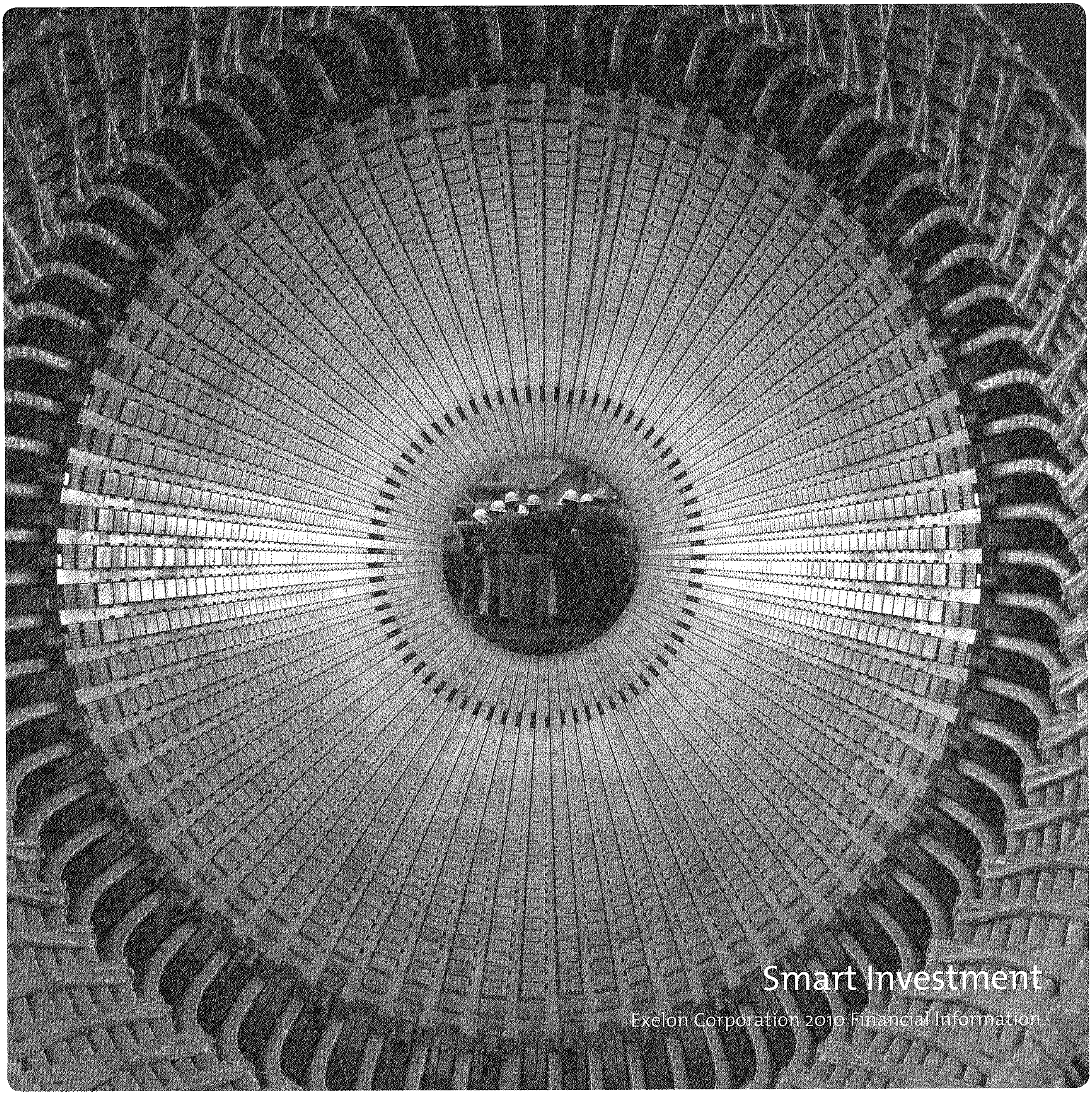
Smart Investment
Exelon Corporation 2010 Financial Information

Exelon Corporation 10 Financial Information

CORPORATE PROFILE

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INVESTOR AND GENERAL INFORMATION

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Independent Public Accountants
PricewaterhouseCoopers LLP

Website
www.exeloncorp.com

Stock Ticker
EXC

Shareholder Inquiries
Exelon Corporation has appointed Wells Fargo Shareowner Services as its transfer agent, stock registrar, dividend disbursing agent and dividend reinvestment agent. Should you have questions concerning your registered shareholder account or the payment or reinvestment of your dividends, or if you wish to make a stock transaction or stock transfer, you may call shareowner services at Wells Fargo at the toll-free number shown to the left or access their website at www.shareowneronline.com

Computershare Trust Company N.A. administers the Employee Stock Purchase Plan (ESPP), the Employee Stock Purchase Plan for Unincorporated Subsidiaries (ESPPUS), and employee stock options. Should you have any questions concerning your employee plan shares or wish to make a transaction, you may call the toll-free number for Employee Plan Services shown to the left or access their website at www-us.computershare.com/employee.

The Company had approximately 130,000 holders of record of its common stock as of December 31, 2010.

The 2010 Form 10-K Annual Report to the Securities and Exchange Commission was filed on February 10, 2011. To obtain a copy without charge, write to Katherine K. Combs, Senior Vice President, Corporate Governance, Deputy General Counsel and Corporate Secretary, Exelon Corporation, Post Office Box 805379, Chicago, Illinois 60680-5379.

The Company maintains a telephone information service, which enables investors to obtain currently available information on financial performance, company news and to access shareholder services at Wells Fargo. To use this service, please call our toll-free number, 866.530.8108.

TABLE OF CONTENTS

GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon's holding company
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Enterprises	Exelon Enterprises Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
ComEd Funding	ComEd Funding LLC
CTFT	ComEd Transitional Funding Trust
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd and PECO, collectively

Other Terms and Abbreviations

1998 restructuring settlement	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
ASLB	Atomic Safety Licensing Board
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CFL	Compact Fluorescent Light
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
CPI	Consumer Price Index
CTC	Competitive Transition Charge
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP Program	Default Service Provider Program
EE&C	Energy Efficiency and Conservation/Demand
EGS	Electric Generation Supplier
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas

GSA	Generation Supply Adjustment
GWh	Gigawatt hour
HAP	Hazardous air pollutants
HB 80	Pennsylvania House Bill No. 80
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
IFRS	International Financial Reporting Standards
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out
LLRW	Low-Level Radioactive Waste
LTIP	Long-Term Incentive Plan
MGP	Manufactured Gas Plant
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investor Service
mmcf	Million Cubic Feet
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NJDEP	New Jersey Department of Environmental Protection
Non-Regulatory Agreement Units	Former AmerGen nuclear generating units and portions of the Peach Bottom nuclear generating units whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
PPA	Power Purchase Agreement
PCCA	Pennsylvania Climate Change Act
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PUHCA	Public Utility Holding Company Act of 1935
PURTA	Pennsylvania Public Realty Tax Act

RCRA	Federal Resource Conservation and Recovery Act
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Former ComEd and former PECO nuclear generating units whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
SECA	Seams Elimination Charge/Cost Adjustments/Assignment
SERP	Supplemental Employee Retirement Plan
SFC	Supplier Forward Contract
SGIG	Smart Grid Investment Grant
SILO	Sale-In, Lease-Out
SMP	Smart Meter Program
SNF	Spent Nuclear Fuel
SSCM	Simplified Service Cost Method
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
TEG	Termoelectrica del Golfo
TEP	Termoelectrica Penoles
VIE	Variable Interest Entity

FILING FORMAT

The information included within this Financial Information supplement has been taken from Exelon's Form 10-K annual report for the year ended December 31, 2010. That annual report was filed with the SEC on February 10, 2011 and can be viewed and retrieved through the SEC's website at *www.sec.gov* or our website at *www.exeloncorp.com*. We encourage you to consider the entire Form 10-K annual report, which contains more information about us and our subsidiaries than is presented in this financial information supplement.

FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this Financial Information supplement 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 Exelon include those factors discussed herein or in Exelon's 2010 Form 10-K, including those discussed in (a) Risk Factors, (b) Management's Discussion and Analysis of Financial Condition and Results of Operation, (c) Financial Statements and Supplementary Data: Note 18 and (d) other factors discussed in filings with the SEC by Exelon. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Financial Information supplement. Exelon does not undertake any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Financial Information supplement.

WHERE TO FIND MORE INFORMATION

Exelon's 2010 Form 10-K is available on Exelon's website at *www.exeloncorp.com* and will be made available, without charge, in print to any shareholder who requests such documents from Bruce G. Wilson, Senior Vice President, Deputy General Counsel, and Corporate Secretary, Exelon Corporation, P.O. Box 805379, Chicago, Illinois 60680-5379.

GENERAL DESCRIPTION OF OUR BUSINESS

General

Exelon, a utility services holding company, operates through its principal subsidiaries—Generation, ComEd and PECO—as described below, each of which is treated as a reportable segment by Exelon. See Note 20 of the Combined Notes to Consolidated Financial Statements for additional segment information.

Exelon was incorporated in Pennsylvania in February 1999. Exelon's principal executive offices are located at 10 South Dearborn Street, Chicago, Illinois 60603, and its telephone number is 312-394-7398.

Generation

Generation's business consists of its owned and contracted electric generating facilities, its wholesale energy marketing operations and its competitive retail supply operations. Generation has three reportable segments consisting of the Mid-Atlantic, Midwest, and South and West regions.

Generation was formed in 2000 as a Pennsylvania limited liability company. Generation began operations as a result of a corporate restructuring, effective January 1, 2001, in which Exelon separated its generation and other competitive businesses from its regulated energy delivery businesses at ComEd and PECO. Generation's principal executive offices are located at 300 Exelon Way, Kennett Square, Pennsylvania 19348, and its telephone number is 610-765-5959.

ComEd

ComEd's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in northern Illinois, including the City of Chicago.

ComEd was organized in the State of Illinois in 1913 as a result of the merger of Cosmopolitan Electric Company into the original corporation named Commonwealth Edison Company, which was incorporated in 1907. ComEd's principal executive offices are located at 440 South LaSalle Street, Chicago, Illinois 60605, and its telephone number is 312-394-4321.

PECO

PECO's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia.

PECO was incorporated in Pennsylvania in 1929. PECO's principal executive offices are located at 2301 Market Street, Philadelphia, Pennsylvania 19103, and its telephone number is 215-841-4000.

Generation

Generation is one of the largest competitive electric generation companies in the United States, as measured by owned and controlled MW. Generation combines its large generation fleet with an experienced wholesale energy marketing operation and a competitive retail supply operation. Generation's presence in well-developed wholesale energy markets, integrated hedging strategy that mitigates the adverse impact of short-term market volatility, and low-cost nuclear generating fleet, which is operated consistently at high capacity factors, position it well to succeed in competitive energy markets.

At December 31, 2010, Generation owned generation resources with an aggregate net capacity of 25,619 MW, including 17,047 MW of nuclear capacity. Generation controlled another 6,139 MW of capacity through long-term contracts.

Generation's wholesale marketing unit, Power Team, draws upon Generation's energy generation portfolio and logistical expertise to ensure delivery of energy to Generation's wholesale customers under long-term and short-term contracts and in spot markets.

Generation's retail business provides retail electric and gas services as an unregulated retail energy supplier in Illinois, Pennsylvania, Michigan and Ohio. Generation's retail business is dependent upon continued deregulation of retail electric and gas markets and Generation's ability to obtain supplies of electricity and gas at competitive prices in the wholesale market.

Generation is a public utility under the Federal Power Act, which gives the FERC exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, FERC has the authority to grant or deny market-based rates for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. The FERC's jurisdiction over ratemaking also includes the authority to suspend the market-based rates of utilities (including Generation, which is a public utility as FERC defines that term) and set cost-based rates should the FERC find that its previous grant of market-based rates authority is no longer just and reasonable. Other matters subject to FERC jurisdiction include, but are not limited to, third-party financings; review of mergers; dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility; affiliate transactions; intercompany financings and cash management arrangements; certain internal corporate reorganizations; and certain holding company acquisitions of public utility and holding company securities. Specific operations of Generation are also subject to the jurisdiction of various other Federal, state, regional and local agencies, including the NRC and Federal and state environmental protection agencies. Additionally, Generation is subject to mandatory reliability standards promulgated by the NERC, with the approval of the FERC.

RTOs exist in a number of regions to provide transmission service across multiple transmission systems. To date, PJM, the MISO, ISO-NE and Southwest Power Pool, have been approved as RTOs. These entities are responsible for regional planning, managing transmission congestion, developing larger wholesale markets for energy and capacity, maintaining reliability, market monitoring and the elimination or reduction of redundant transmission charges imposed by multiple transmission providers when wholesale customers take transmission service across several transmission systems.

Generating Resources

At December 31, 2010, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets [(a)]	
Nuclear	17,047
Fossil [(b)]	6,189
Hydroelectric/Renewable [(c)]	2,383
Owned generation assets	25,619
Long-term contracts [(d)]	6,139
Total generating resources	31,758

(a) See "Fuel" for sources of fuels used in electric generation.
(b) Includes 933 MW of capacity related to Units 1 and 2 at Cromby Generating Station and Units 1 and 2 at Eddystone Generating Station, which were approved for retirement by the Exelon Board of Directors on December 1, 2009. See Note 14 of the Combined Notes to Consolidated Financial Statements for further details.
(c) Includes Exelon Wind assets acquired on December 9, 2010. See Note 3 of the Combined Notes to Consolidated Financial Statements for further details.
(d) Long-term contracts range in duration up to 21 years.

Generation has three reportable segments, the Mid-Atlantic, Midwest, and South and West, representing the different geographical areas in which Generation's power marketing activities are conducted and where Generation's owned and contracted generating resources are located. Mid-Atlantic represents Generation's operations primarily in Pennsylvania, New Jersey and Maryland (approximately 36% of capacity); Midwest includes the operations in Illinois, Indiana, Michigan and Minnesota (approximately 46% of capacity); and the South and West includes operations primarily in Texas, Georgia, Oklahoma, Kansas, Missouri, Idaho and Oregon (approximately 18% of capacity).

Nuclear Facilities

Generation has ownership interests in eleven nuclear generating stations currently in service, consisting of 19 units with an aggregate of 17,047 MW of capacity. Generation wholly-owns all of its nuclear generating stations, except for Quad Cities Generating Station (75% ownership), Peach Bottom Generating Station (50% ownership) and Salem Generating Station (Salem) (42.59% ownership). Generation's nuclear generating stations are all operated by Generation, with the exception of the two units at Salem, which are operated by PSEG Nuclear, LLC (PSEG Nuclear), an indirect, wholly owned subsidiary of PSEG. In 2010 and 2009, electric supply (in GWh) generated from the nuclear generating facilities was 82% and 81%, respectively, of Generation's total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. See Management's Discussion and Analysis of Financial Condition and Results of Operations for further discussion of Generation's electric supply sources.

AmerGen Reorganization. AmerGen, a wholly owned subsidiary of Generation through January 8, 2009, owned and operated the Clinton Nuclear Power Station (Clinton), the Three Mile Island (TMI) Unit No. 1 and the Oyster Creek Generating Station (Oyster Creek) through that time. Effective January 8, 2009, AmerGen was merged into Generation, which now holds the operating licenses for Clinton, TMI and Oyster Creek.

Oyster Creek Station Shutdown. On December 8, 2010, in connection with the executed Administrative Consent Order (ACO) with the NJDEP, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information regarding the closure of Oyster Creek.

Nuclear Operations. Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, can have a significant impact on Generation's results of operations. As the largest generator of nuclear power in the United States, Generation can negotiate favorable terms for the materials and services that its business requires. Generation's nuclear plants have historically benefited from minimal environmental impact from operations and a safe operating history.

During 2010 and 2009, the nuclear generating facilities operated by Generation achieved capacity factors of 93.9% and 93.6%, respectively. Generation aggressively manages its scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable generation base for Generation's short and long-term supply commitments and Power Team marketing and trading activities. During scheduled refueling outages, Generation performs maintenance and equipment upgrades in order to minimize the occurrence of unplanned outages and to maintain safe reliable operations.

In addition to the rigorous maintenance and equipment upgrades performed by Generation during scheduled refueling outages, Generation has extensive operating and security procedures in place to ensure the safe operation of the nuclear units. Generation has extensive safety systems in place to protect the plant, personnel and surrounding area in the unlikely event of an accident.

Regulation of Nuclear Power Generation. Generation is subject to the jurisdiction of the NRC with respect to the operation of its nuclear generating stations, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously assesses unit performance indicators and inspection results, and communicates its assessment on a semi-annual basis. As of December 31, 2010, the NRC categorized each unit operated by Generation in the Licensee Response Column, which is the highest performance band. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures for nuclear generating facilities and/or increased operating costs of nuclear generating units.

Licenses. Generation has 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals for Peach Bottom Units 2 and 3, Dresden Units 2 and 3, Quad Cities Units 1 and 2, Oyster Creek and Three Mile Island Unit 1. The following table summarizes the current operating license expiration dates for Generation's nuclear facilities in service:

Station	Unit	In-Service Date [(a)]	Current License Expiration
Braidwood [(b)]	1	1988	2026
	2	1988	2027
Byron [(b)]	1	1985	2024
	2	1987	2026
Clinton [(c)]	1	1987	2026
Dresden [(b)(e)]	2	1970	2029
	3	1971	2031
LaSalle [(b)]	1	1984	2022
	2	1984	2023
Limerick [(d)]	1	1986	2024
	2	1990	2029
Oyster Creek [(d)(e)(f)]	1	1969	2029
Peach Bottom [(d)(e)]	2	1974	2033
	3	1974	2034
Quad Cities [(b)(e)]	1	1973	2032
	2	1973	2032
Salem [(d)]	1	1977	2016
	2	1981	2020
Three Mile Island [(c)(e)]	1	1974	2034

(a) Denotes year in which nuclear unit began commercial operations.
(b) Stations previously owned by ComEd.
(c) Stations previously owned by AmerGen.
(d) Stations previously owned by PECO.
(e) Stations for which the NRC has issued a renewed operating licenses for Dresden Unit 2 and Unit 3.
(f) On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.

On May 29, 2009, a coalition of citizen groups filed a Petition for Review of the NRC's renewal of Oyster Creek's operating license in the United States Court of Appeals for the Third Circuit. Oral argument was held before the Court on January 5, 2011. If the appeal is successful, it is unlikely that it would result in a revocation of the renewed license; however, it could cause the NRC to impose additional conditions over the course of the period of extended operation.

On August 18, 2009, PSEG submitted an application to the NRC to extend the operating licenses of Salem Units 1 and 2 by 20 years. The NRC is expected to spend a total of 22 to 30 months to review the application before making a decision.

Generation expects to apply for and obtain approval of license renewals for the remaining nuclear units. The operating license renewal process takes approximately four to five years from the commencement of the renewal process until completion of the NRC's review. The NRC review process takes approximately two years from the docketing of an application. Each requested license renewal is expected to be for 20 years beyond the original license expiration. Depreciation provisions are based on the estimated useful lives of the stations, which reflect the actual and assumed renewal of operating licenses for all of Generation's operating nuclear generating stations.

Nuclear Uprate Program. During 2009, Generation announced a series of planned power uprates across its nuclear fleet that will result in between 1,300 and 1,500 MW of additional generation capacity within eight years. The uprate projects represent a total investment of approximately $3.65 billion in overnight cost, as measured in 2010 dollars. Using proven technologies, the projects take advantage of new production and measurement technologies, new materials and learning from a half-century of nuclear power operations. Uprate projects, representing approximately 60% of the planned uprate MW, are underway at the Limerick and Peach Bottom nuclear stations in Pennsylvania and the Byron, Braidwood, Dresden, LaSalle and Quad Cities plants in Illinois. The remainder will come from additional projects across Generation's nuclear fleet beginning in 2011 and ending in 2017. At 1,500 nuclear-generated MW, the uprates would displace 8 million metric tons of carbon emissions annually that would otherwise come from burning fossil fuels. The uprates are being undertaken pursuant to an organized, strategically sequenced implementation plan. The implementation effort includes a periodic review and refinement of the projects in light of changing market conditions. As part of this periodic review process, the uprate project at Three Mile Island is currently under evaluation. The amount of expenditures to implement the plan ultimately will depend on economic and policy developments, and will be made on a project-by-project basis in accordance with Exelon's normal project evaluation standards. The ability to implement several projects requires the successful resolution of various technical issues. The resolution of these issues may affect the timing and amount of the power increases associated with the power uprate initiative. Through December 31, 2010, Generation has added 101 MWs of nuclear generation through its uprate program, with another 98 MWs scheduled to be added in 2011.

New Site Development. Generation is keeping open the option of a new nuclear plant located in Victoria County in southeast Texas; however, Generation has not made a decision to build a nuclear plant at this time. In response to the overall downturn of the economy and the projection of sustained, low natural gas prices, Exelon revised its new nuclear plant development strategy. Exelon had previously submitted a Combined Construction and Operating License (COL) application to the NRC for the Victoria site. On March 25, 2010, Exelon submitted an application for an Early Site Permit (ESP) application for the site and subsequently withdrew its COL application. The ESP allows Exelon to establish the suitability of the Victoria site, which lessens the amount of work to do should it later decide to reapply for a COL. Additionally, the ESP accommodates a variety of possible future plant designs, allowing for flexibility in selecting a reactor technology later as part of a COL application. If approved by the NRC, the ESP would effectively reserve the site for 20 years with the possibility of renewal for another 20 years. Any decision to build at the Victoria County site would be made later based on then current economics. The Exelon board authorized a budget of $130 million for the Victoria County project, of which a total of $108 million had been expensed through December 31, 2010. The review and approval schedule published by the NRC estimates final issuance of the ESP in late 2014.

Nuclear Waste Disposal. There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the United States, nor has the NRC licensed any such facilities. Generation currently stores all SNF generated by its nuclear generating facilities in on-site storage pools or in dry cask storage facilities. Since Generation's SNF storage pools generally do not have sufficient storage capacity for the life of the respective plant, Generation has developed dry cask storage facilities to support operations.

As of December 31, 2010, Generation had approximately 54,300 SNF assemblies (13,100 tons) stored on site in SNF pools or dry cask storage (this includes SNF at Zion Station, for which Generation retains ownership, see Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning). On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at Generation's sites through the end of the license renewal periods, and through decommissioning. The following table describes the current status of Generation's SNF storage facilities.

Site	Date for loss of full core reserve [(a)]
Braidwood	2012
Byron	Dry cask storage in operation
Clinton	2018
Dresden	Dry cask storage in operation
LaSalle	Dry cask storage in operation
Limerick	Dry cask storage in operation
Oyster Creek	Dry cask storage in operation
Peach Bottom	Dry cask storage in operation
Quad Cities	Dry cask storage in operation
Salem	Dry cask storage in operation
Three Mile Island [(b)]	2023

(a) The date for loss of full core reserve identifies when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core. Dry cask storage will be in operation at those sites prior to the closing of their on-site storage pools.

(b) The DOE previously has indicated it will begin accepting spent fuel in 2020. If this does not occur, Three Mile Island will need an onsite dry cask storage facility.

For a discussion of matters associated with Generation's contracts with the DOE for the disposal of SNF, see Note 18 of the Combined Notes to Consolidated Financial Statements.

As a by-product of their operations, nuclear generating units produce LLRW. LLRW is accumulated at each generating station and permanently disposed of at Federally licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into an agreement, although neither state currently has an operational site and none is anticipated to be operational until after 2020. Pennsylvania, which had agreed to be the host site for LLRW disposal facilities for generators located in Pennsylvania, Delaware, Maryland and West Virginia, has suspended the search for a permanent disposal site.

Generation is currently utilizing on-site storage capacity at its nuclear generation stations for limited amounts of LLRW and has been shipping its Class A LLRW, which represent 93% of LLRW generated at its stations, to disposal facilities in Utah and South Carolina. The disposal facility in South Carolina at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey (which includes Oyster Creek and Salem), and Connecticut. Generation has pending license amendments for its Peach Bottom and LaSalle stations that will allow it to store LLRW from its remaining stations that have limited capacity. If approved, there will enough storage capacity to store all Class B and C LLRW for the life of all stations in Generations nuclear fleet. Generation continues to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize cost impacts and on-site storage.

Nuclear Insurance. Generation is subject to liability, property damage and other risks associated with a major accidental outage at any of its nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See "Nuclear Insurance" within Note 18 of the Combined Notes to Consolidated Financial Statements for details.

For information regarding property insurance, see ITEM 2. Properties—Generation of Exelon's 2010 Form 10-K. Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for its insured losses. Such losses could have a material adverse effect on Exelon's and Generation's financial condition and results of operations.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. See Management's Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates, Nuclear Decommissioning Asset Retirement Obligations and Nuclear Decommissioning Trust Fund Investments; and Notes 2, 8 and 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding Generation's NDT funds and its decommissioning obligations.

Dresden Unit 1 and Peach Bottom Unit 1 have ceased power generation. SNF at Dresden Unit 1 is currently being stored in dry cask storage until a permanent repository under the NWPA is completed. All SNF for Peach Bottom Unit 1, which ceased operation in 1974, has been removed from the site and the SNF pool is drained and decontaminated. Generation's estimated liability to decommission Dresden Unit 1 and Peach Bottom Unit 1 was $182 million at December 31, 2010. As of December 31, 2010, NDT funds set aside to pay for these obligations were $330 million.

Zion Station Decommissioning. On December 11, 2007, Generation entered into an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC. (EnergySolutions) and ZionSolutions, under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998.

On September 1, 2010, Generation and EnergySolutions completed the transactions contemplated by the ASA. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities associated with Zion Station. Pursuant to the ASA, ZionSolutions can periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. However, ZionSolutions is subject to certain restrictions on its ability to request reimbursement; specifically, if certain milestones as defined in the ASA are not met, all or a portion of requested reimbursements shall be deferred until such milestones are met. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning.

Fossil, Hydroelectric and Renewable Facilities

Generation operates various fossil, hydroelectric and renewable facilities and maintains ownership interests in several other facilities including LaPorte, Keystone, Conemaugh and Wyman, which are operated by third parties. In 2010 and 2009, electric supply (in GWh) generated from owned fossil, hydroelectric and renewable generating facilities was 6% of Generation's total electric supply. The majority of this output was dispatched to support Generation's power marketing activities. For additional information regarding Generation's electric generating facilities, see ITEM 2. Properties—Generation of Exelon's 2010 Form 10-K.

John Deere Renewables. On December 9, 2010, Generation acquired all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind), a leading operator and developer of wind power, for approximately $893 million in cash. Generation acquired 735 MWs of installed, operating wind capacity located in eight states. Approximately 75% of the operating portfolio's expected output is already sold under long-term power purchase arrangements. Additionally, Generation will pay up to $40 million related to three projects with a capacity of 230 MWs which are currently in advanced stages of development, contingent upon meeting certain contractual commitments related to the commencement of construction of each project. This contingent consideration was valued at $32 million of which approximately $16 million has been recorded as a current liability and the remainder has been recorded as a noncurrent liability. As a result, total consideration recorded for the Exelon Wind acquisition was $925 million. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Exelon Wind acquisition.

Plant Retirements. On December 2, 2009, Exelon announced its intention to permanently retire three coal-fired generating units and one oil/gas-fired generating unit, effective May 31, 2011. The units to be retired are Cromby Generating Station (Cromby) Unit 1 and Unit 2 and Eddystone Generating Station (Eddystone) Unit 1 and Unit 2. These actions were in response to the economic outlook related to the continued operation of these four units. Subsequently, PJM determined that transmission reliability upgrades will be necessary to alleviate reliability impacts and that those upgrades will be completed in a manner that will permit Generation's retirement of the units on the following schedule: Cromby Unit 1 and Eddystone Unit 1 on May 31, 2011; Cromby Unit 2 on December 31, 2011; and Eddystone Unit 2 on June 1, 2012. These dates are dependent upon the completion of required transmission reliability upgrades and may be subject to further change. Generation revised the depreciable useful lives for the affected units to reflect the revised deactivation dates. For more information regarding plant retirements, see Note 14 of the Combined Notes to Consolidated Financial Statements.

Licenses. Fossil and renewable generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways or Federal lands, or connected to the interstate electric grid. The license for the Conowingo Hydroelectric Project expires on August 31, 2014 and for the Muddy Run Pumped Storage Facility Project expires on September 1, 2014. In March 2009, Generation filed a Pre-Application Document and Notice of Intent to renew the licenses, pursuant to FERC relicensing requirements. For those plants located within the control areas administered by PJM or the New England control area administered by ISO-NE, notice is required to be provided to PJM or ISO-NE, as applicable, before a plant can be retired.

Insurance. Generation does not purchase business interruption insurance for its wholly owned fossil and hydroelectric operations. Generation maintains both property damage and liability insurance. For property damage and liability claims, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon and Generation's financial condition and their results of operations and cash flows. For information regarding property insurance, see ITEM 2. Properties—Generation of Exelon's 2010 Form 10-K.

Long-Term Contracts

In addition to energy produced by owned generation assets, Generation sells electricity purchased under the following long-term contracts in effect as of December 31, 2010:

Seller	Location	Expiration	Capacity (MW)
Kincaid Generation, LLC	Kincaid, Illinois	2013	1,108
Tenaska Georgia Partners, LP (a)	Franklin, Georgia	2030	945
Tenaska Frontier, Ltd	Shiro, Texas	2020	830
Green Country Energy, LLC (b)	Jenks, Oklahoma	2022	778
Elwood Energy, LLC	Elwood, Illinois	2012	775
Lincoln Generating Facility, LLC	Manhattan, Illinois	2011	664
Wolf Hollow	Granbury, Texas	2023	350
Old Trail Windfarm, LLC	McLean, Illinois	2026	198
Others (c)	Various	2011 to 2028	491
Total			6,139

(a) Generation has sold its rights to 945 MW of capacity, energy, and ancillary services supplied from its existing long-term contract with Tenaska Georgia Partners, LP through a PPA with Georgia Power, a subsidiary of Southern Company for a 20 year period that began on June 1, 2010.

(b) Commencing June 1, 2012 and lasting for 10 years, Generation has agreed to sell its rights to 520 MW, or approximately two-thirds, of capacity, energy, and ancillary services supplied from its existing long-term contract with Green Country Energy, LLC through a PPA with Public Service Company of Oklahoma, a subsidiary of American Electric Power Company, Inc..

(c) Includes long-term capacity contracts with seven counterparties.

Fuel

The following table shows sources of electric supply in GWh for 2010 and estimated for 2011:

	Source of Electric Supply (a)	
	2010	2011 (Est.)
Nuclear	140,010	139,375
Purchases—non-trading portfolio	21,062	18,055
Fossil, renewable and hydroelectric	10,717	11,253
Total supply	171,789	168,683

(a) Represents Generation's proportionate share of the output of its generating plants.

The fuel costs for nuclear generation are substantially less than for fossil-fuel generation. Consequently, nuclear generation is generally the most cost-effective way for Generation to meet its wholesale obligations, including to ComEd and PECO, and some of Generation's retail business requirements.

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride and the fabrication of fuel assemblies. Generation has uranium concentrate inventory and supply contracts sufficient to meet all of its uranium concentrate requirements through 2015. Generation's contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2015. All of Generation's enrichment requirements have been contracted through 2012. Contracts for fuel fabrication have been obtained through 2013. Generation does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or fabrication services to meet the nuclear fuel requirements of its nuclear units.

Coal is procured primarily through annual supply contracts, with the remainder supplied through either short-term contracts or spot-market purchases.

Natural gas is procured through annual, monthly and spot-market purchases. Some fossil generation stations can use either oil or natural gas as fuel. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

Generation uses financial instruments to mitigate price risk associated with certain commodity price exposures. Generation also hedges forward price risk with both over-the-counter and exchange-traded instruments. See Risk Factors, Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates and Note 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Team

Generation's wholesale marketing and retail electric supplier operations include the physical delivery and marketing of power obtained through its generation capacity and through long-term, intermediate-term and short-term contracts. Generation seeks to maintain a net positive supply of energy and capacity, through ownership of generation assets and power purchase and lease agreements, to protect it from the potential operational failure of one of its owned or contracted power generating units. Generation has also contracted for access to additional generation through bilateral long-term PPAs. PPAs are commitments related to power generation of specific generation plants and/or are dispatchable in nature similar to asset ownership. Generation enters into PPAs as part of its overall strategic plan, with objectives such as obtaining low-cost energy supply sources to meet its physical delivery obligations to customers and assisting customers to meet renewable portfolio standards. Generation may buy power to meet the energy demand of its customers, including ComEd and PECO. These purchases may be for more than the energy demanded by Power Team's customers. Power Team then sells this open position, along with capacity not used to meet customer demand, in the wholesale electricity markets. Where necessary, Generation also purchases transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs in markets without an organized RTO. Generation also incorporates contingencies into its planning for extreme weather conditions, including potentially reserving capacity to meet summer loads at levels representative of warmer-than-normal weather conditions.

Generation also manages the price and supply risks for energy and fuel associated with generation assets and the risks of power marketing activities. Generation implements a three-year ratable sales plan to align its hedging strategy with its financial objectives. Generation also enters into transactions that are outside of this ratable sales plan, such as a financial swap with ComEd that is described below and runs into 2013. However, except for the ComEd swap arrangement, Generation is exposed to relatively greater commodity price risk beyond 2011 for which a larger portion of its electricity portfolio may be unhedged. Generation has been and will continue to be proactive in using hedging strategies to mitigate this risk in subsequent years. As of December 31, 2010, the percentage of expected generation hedged was 90%-93%, 67%-70%, and 32%-35% for 2011, 2012 and 2013, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include cash flow hedges, other derivatives and certain non-derivative contracts, including sales to ComEd and PECO to serve their retail load. A portion of Generation's hedging strategy may be implemented through the use of fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. The trading portfolio is subject to a risk management policy that includes stringent risk management limits including volume, stop-loss and value-at-risk limits to manage exposure to market risk. Additionally, the corporate risk management group and Exelon's RMC monitor the financial risks of the power marketing activities. Generation also uses financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of Generation's efforts.

At December 31, 2010, Generation's short and long-term commitments relating to the purchase and sale of energy and capacity from and to unaffiliated utilities and others were as follows:

(in millions)	Net Capacity Purchases (a)	Power Only Purchases (b)	Power Only Sales	Transmission Rights Purchases (c)
2011	$ 291	$ 60	$1,632	$ 9
2012	274	17	758	9
2013	151	—	314	6
2014	147	—	149	—
2015	141	—	150	—
Thereafter	940	—	670	—
Total	$1,944	$ 77	$3,673	$ 24

(a) Net capacity purchases include PPAs and other capacity contracts that are accounted for as operating leases. Amounts presented as commitments represent Generation's expected payments under these arrangements at December 31, 2010, including certain capacity charges which are subject to plant availability.
(b) Excludes renewable energy PPA contracts that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

ComEd procures all of its electricity through a competitive procurement process, through which Generation supplies a portion of ComEd's load. Additionally, in order to fulfill a requirement of the Illinois Settlement, Generation and ComEd entered into a five-year financial swap contract that expires on May 31, 2013. See ComEd—Retail Electric Services, Procurement Related Proceedings for additional information regarding ComEd's procurement-related proceedings and the financial swap contract.

Generation had a PPA with PECO under which Generation supplied PECO with all of PECO's electric supply needs through December 31, 2010. Generation supplied electricity to PECO from its portfolio of generation assets, PPAs and other market sources. As of January 1, 2011, PECO procures all of its electricity through a competitive procurement process, through which Generation will continue to supply a portion of PECO's load. See PECO—Retail Electric Services, Procurement Related Proceedings for additional information regarding PECO's competitive, full-requirements energy-supply procurement process after 2010.

Capital Expenditures

Generation's business is capital intensive and requires significant investments in energy generation and in other internal infrastructure projects. Generation's estimated capital expenditures for 2011 are as follows:

(in millions)	
Nuclear fuel [(a)]	$1,025
Production plant	850
Uprates	475
Wind	225
Total	$2,575

(a) Includes Generation's share of the investment in nuclear fuel for the co-owned Salem plant.

ComEd

ComEd is engaged principally in the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to a diverse base of residential, commercial and industrial customers in northern Illinois. ComEd is a public utility under the Illinois Public Utilities Act subject to regulation by the ICC related to distribution rates and service, the issuance of securities, and certain other aspects of ComEd's business. ComEd is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of ComEd's business. Specific operations of ComEd are also subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, ComEd is subject to mandatory reliability standards set by the NERC.

ComEd's retail service territory has an area of approximately 11,300 square miles and an estimated population of 9 million. The service territory includes the City of Chicago, an area of about 225 square miles with an estimated population of 3 million. ComEd has approximately 3.8 million customers.

ComEd's franchises are sufficient to permit it to engage in the business it now conducts. ComEd's franchise rights are generally nonexclusive rights documented in agreements and, in some cases, certificates of public convenience issued by the ICC. With few exceptions, the franchise rights have stated expiration dates ranging from 2011 to 2066. ComEd anticipates working with the appropriate agencies to extend or replace the franchise agreements prior to expiration.

ComEd's kWh sales and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. ComEd's highest peak load occurred on August 1, 2006 and was 23,613 MW; its highest peak load during a winter season occurred on January 15, 2009 and was 16,328 MW.

Retail Electric Services

Under Illinois law, transmission and distribution service is regulated, while electric customers are allowed to purchase generation from a competitive electric generation supplier.

At December 31, 2010, approximately 66,200 retail customers (primarily commercial and industrial customers), representing approximately 52% of ComEd's annual retail kWh sales, had elected to purchase their electricity from a competitive electric generation supplier. There are currently a minimal number of residential customers being served by alternate suppliers. Customers who receive electricity from a competitive electric generation supplier continue to pay a delivery charge to ComEd. Under the current regulatory mechanisms in effect, ComEd is permitted to recover its electricity procurement costs from retail customers, without mark-up. Thus, although energy sales affect ComEd's reported revenues, they do not affect its net income, as the energy sales are offset by equal amount of purchased power expense.

Under Illinois law, ComEd is required to deliver electricity to all customers. ComEd's obligation to provide generation supply service, which is referred to as a POLR obligation, primarily varies by customer size. ComEd's obligation to provide such service to residential customers and other small customers with demands of under 100 kW continues for all customers who do not or cannot choose a competitive electric generation supplier or who choose to return to the utility after taking service from a competitive electric generation supplier. ComEd does not have a fixed-price generation supply service obligation to most of its largest customers with demands of 100 kW or greater, as this group of customers has previously been declared competitive. Beginning June 2010 ComEd had no fixed price generation supply service obligations for customers with demands of 100-400 kW. Customers with competitive declarations may still purchase power and energy from ComEd, but only at hourly market prices.

Procurement Related Proceedings. ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Beginning on January 1, 2007, ComEd procured 100% of energy to meet its load service requirements through ICC-approved staggered SFCs with various suppliers, including Generation. Beginning in June 2009, under the Illinois Settlement Legislation, the IPA designs, and the ICC approves an electricity supply portfolio for ComEd and administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. In order to fulfill a requirement of the Illinois Settlement, ComEd hedged the price of a significant portion of energy purchased on the spot market with a five-year variable-to-fixed financial swap contract with Generation that expires on May 31, 2013. See Notes 2 and 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding ComEd's procurement-related proceedings and the financial swap contract.

Electric Distribution Rate Cases. The ICC issued an order in ComEd's 2007 electric distribution rate case approving a $274 million increase in ComEd's annual delivery services revenue requirement, which became effective in September 2008. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). The Court issued a decision on September 30, 2010, ruling against ComEd on the treatment of post-test year accumulated depreciation and the recovery of costs for an AMI/ Customer Applications pilot program via a rider (Rider SMP). On November 18, 2010, the Court denied ComEd's petition for rehearing in connection with the September 30, 2010 ruling. On January 25, 2011, ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court. Subsequent to the Illinois Appellate Court's ruling, ComEd filed a request with the ICC to allow it to request recovery, through inclusion in the 2010 Rate Case, of $3 million in operation and maintenance costs, as well as carrying costs associated with capital investment in the ICC-approved AMI/Customer Applications pilot program. The AMI pilot program capital investment had already been requested in rate base in the 2010 Rate Case. On December 2, 2010, the ICC approved ComEd's request. The investment and the pilot program costs are subject to challenge in the 2010 Rate Case proceeding.

On June 30, 2010, ComEd requested ICC approval for an increase of $396 million, subsequently changed to $326 million, to its annual delivery services revenue requirement (2010 Rate Case) to allow ComEd to continue modernizing its electric delivery system and recover the costs of substantial investments made since its last rate filing in 2007. The requested rate increase also reflects increased costs, most notably pension and OPEB, since ComEd's rates were last determined. The Court's September 30, 2010 ruling in connection with ComEd's 2007 electric distribution rate case makes it highly unlikely that the ICC would decide the post-test year accumulated depreciation issue in ComEd's favor in the 2010 Rate Case. ComEd estimates that its requested revenue requirement increase of $326 million could be reduced by approximately $85 million as a result of this adjustment. Certain parties have submitted testimony recommending significant reductions to ComEd's requested increase as well as the write-off of certain assets, most notably the regulatory asset associated with severance costs, which was approximately $74 million as of December 31, 2010. Management believes the regulatory asset is appropriate based on the ICC's orders in ComEd's last two rate cases. The new electric distribution rates are expected to take effect no later than June 2011. ComEd cannot predict how much of the requested electric distribution rate increase the ICC may approve. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's rate case proceedings.

Other. Illinois law provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) 30,000 or more customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law. ComEd does not believe that during the years 2010, 2009 and 2008 it had any interruptions that have triggered this damage liability or reimbursement requirement.

Construction Budget

ComEd's business is capital intensive and requires significant investments primarily in energy transmission and distribution facilities, to ensure the adequate capacity and reliability of its system. Based on PJM's RTEP, ComEd has various construction commitments, as discussed in Note 18 of the Combined Notes to Consolidated Financial Statements. ComEd's most recent estimate of capital expenditures for electric plant additions and improvements for 2011 is $1,015 million which includes RTEP projects. See Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources for further information.

PECO

PECO is engaged principally in the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia. PECO is a public utility under the Pennsylvania Public Utility Code subject to regulation by the PAPUC as to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of PECO's operations. PECO is a public utility under the Federal Power Act subject to regulation by FERC as to transmission rates and certain other aspects of PECO's business and by the U.S. Department of Transportation as to pipeline safety and other aspects of gas operations. Specific operations of PECO are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, PECO is also subject to NERC mandatory reliability standards.

PECO's combined electric and natural gas retail service territory has an area of approximately 2,100 square miles and an estimated population of 3.8 million. PECO provides electric delivery service in an area of approximately 1,900 square miles, with a population of approximately 3.8 million, including approximately 1.5 million in the City of Philadelphia. PECO supplies natural gas service in an area of approximately 1,900 square miles in southeastern Pennsylvania adjacent to the City of Philadelphia, with a population of approximately 2.3 million. PECO delivers electricity to approximately 1.6 million customers and natural gas to approximately 490,000 customers.

PECO has the necessary authorizations to deliver regulated electric and natural gas service in the various municipalities or territories in which it now supplies such services. PECO's authorizations consist of charter rights and certificates of public convenience issued by the PAPUC and/or "grandfathered rights," which are rights generally unlimited as to time and generally exclusive from competition from other electric and natural gas utilities. In a few defined municipalities, PECO's natural gas service territory authorizations overlap with that of another natural gas utility but PECO does not consider those situations as posing a material competitive or financial threat.

PECO's kWh sales and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. PECO's highest peak load occurred on August 3, 2006 and was 8,932 MW; its highest peak load during a winter season occurred on December 20, 2004 and was 6,838 MW.

PECO's natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating. PECO's highest daily natural gas send out occurred on January 17, 2000 and was 718 mmcf.

Retail Electric Services

PECO's retail electric sales and distribution revenues are derived pursuant to rates regulated by the PAPUC. Under the 1998 restructuring settlement, PECO's electric generation rates were capped through a transition period which ended on December 31, 2010. During the transition period, PECO was authorized to recover from customers $5.3 billion of costs that might not have otherwise been recovered in a competitive market (stranded costs) with a 10.75% return on the unamortized balance through the imposition and collection of a non-bypassable CTC, which was a component of the capped electric generation rate on customer bills. At December 31, 2010, PECO's stranded costs were fully recovered.

Beginning January 1, 2011, PECO's electric supply procurement cost rates charged to default service customers are subject to quarterly adjustments designed to recover or refund the difference between PECO's actual cost of electricity delivered and the amount included in rates without markup through the GSA.

Pennsylvania permits competition by EGSs for the supply of retail electricity while transmission and distribution service remains regulated under the Competition Act. For the year ended December 31, 2010, less than 1% of PECO's residential and large commercial and industrial and 4% of its small commercial and industrial loads were purchased from alternative EGSs. The small percentage of customer load provided by an alternative EGS is due to the electric generation rate caps that were lower than current market prices throughout the transition period. Customers that choose an alternative EGS are not subject to PECO's electric supply procurement cost rates. In preparation for the transition to market-based competitive pricing, multiple alternative EGSs began marketing to customers in PECO's service territory. As of January 31, 2011, PECO believes that at least 10% of residential, 46% of small commercial and industrial and 86% of large commercial and industrial loads will be purchased from alternative EGSs. Beginning with January 2011 customer bills, PECO presented its electric supply Price to Compare, which will be updated quarterly, to assist customers with the evaluation of offers from alternative EGSs. PECO's average residential Price to Compare for the first three months of 2011 is 9.92 cents per kWh.

Customer selection of an alternative EGS or PECO as default service provider does not impact PECO's results of operations or financial position. PECO's cost of electric supply is passed directly through to default service customers without markup. For those customers that choose an alternative EGS, PECO will act as the billing agent but will not record revenues or expenses related to this electric supply. PECO remains the distribution service provider for all the customers in its service territory and charges a regulated rate for delivery service. PECO receives transmission revenue from PJM for customers that select an alternative EGS.

Procurement Proceedings. Prior to January 1, 2011, PECO procured all its electric supply under a full requirements PPA with Generation, which expired on December 31, 2010. The term and procurement costs under the PPA with Generation corresponded with PECO's transition period and capped electric generation rates in accordance with its 1998 restructuring settlement. Beginning January 1, 2011, PECO's electric supply for its customers is procured through a competitive process in accordance with its PAPUC-approved DSP Program. During 2010, PECO entered into contracts with PAPUC-approved bidders for its third and fourth competitive procurements of electric supply for default electric service commencing January 2011, which included fixed price full requirement contracts for all procurement classes, spot market price full requirements contracts for the commercial and industrial procurement classes, and block energy contracts for the residential procurement class. As of December 31, 2010, including the previous competitive procurements completed in 2009 and 2010, the 2011 expected electric supply for all customer classes had been substantially procured. PECO will conduct five additional competitive procurements for electric supply for all customer classes during the term of its DSP Program.

Electric Distribution Rate Case. In December 2010, the PAPUC approved a settlement of PECO's electric distribution rate case filed in August 2010 that provides for an annual revenue increase of $225 million. The approved electric distribution rates became effective on January 1, 2011. The electric distribution rate case settlement and the electric supply procurement results indicate an increase of 5.1% in the average residential customer total electric bill in January 2011, above 2010 bills.

See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Smart Meter and Energy Efficiency Programs

Smart Meter Programs. In April 2010, the PAPUC approved PECO's $550 million Smart Meter Procurement and Installation Plan, which was filed in accordance with the requirements of Act 129. PECO filed for PAPUC approval of an initial dynamic pricing and customer acceptance program in October 2010, and plans to file for approval of a universal meter deployment plan for its remaining customers in 2012.

Also, in April 2010, PECO entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA. Under the SGIG, PECO has been awarded $200 million, the maximum grant allowable under the program, for its SGIG project—Smart Future Greater Philadelphia. As a result of the SGIG funding, PECO will deploy 600,000 smart meters within three years, accelerate universal deployment of more than 1.6 million smart meters from 15 years to 10 years and increase smart grid investments to approximately $100 million over the next three years. In total, over the next 10 years, PECO is planning to spend up to $650 million on its smart grid and smart meter infrastructure. The SGIG funding will be used to significantly reduce the impact of those investments on PECO customers.

Energy Efficiency Programs. In February 2010, the PAPUC approved PECO's EE&C plan, which was filed pursuant to Act 129's EE&C reduction targets. The approved four-year plan totals more than $330 million and includes a CFL program, weatherization programs, an energy efficiency appliance rebate and trade-in program, rebates and energy efficiency programs for non-profit, educational, governmental and business customers, customer incentives for energy management programs and incentives to help customers reduce energy demand during peak periods. In September 2010, PECO filed revisions to the EE&C Plan previously approved in February 2010 that included adjustments to certain incentive levels and the addition of energy efficiency measures to the existing portfolio. These revisions do not impact the total spending or timely recovery under the approved EE&C plan. On January 27, 2011, the PAPUC unanimously approved PECO's EE&C Plan revisions.

See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Natural Gas

PECO's natural gas sales and distribution revenues are derived pursuant to rates regulated by the PAPUC. PECO's purchased natural gas cost rates, which represent a portion of total rates, are subject to quarterly adjustments designed to recover or refund the difference between the actual cost of purchased natural gas and the amount included in rates without markup through the PGC.

PECO's natural gas customers have the right to choose their natural gas suppliers or to purchase their gas supply from PECO at cost. In 2010, 39% of PECO's current total yearly throughput was provided by natural gas suppliers other than PECO and is related primarily to the supply of PECO's large commercial and industrial customers. Natural gas distribution service provided to customers by PECO remains subject to rate regulation. PECO also provides billing, metering, installation, maintenance and emergency response services at regulated rates.

Procurement Proceedings. PECO's natural gas supply is provided through purchases from a number of suppliers. These purchases are primarily delivered under long-term firm transportation contracts for terms of up to two years. PECO's aggregate annual firm supply under these firm transportation contracts is 46 million dekatherms. Peak natural gas is provided by PECO's liquefied natural gas (LNG) facility and propane-air plant. PECO also has under contract 23 million dekatherms of underground storage through service agreements. Natural gas from underground storage represents approximately 30% of PECO's 2010-2011 heating season planned supplies.

Natural Gas Distribution Rate Cases. On January 1, 2009, PECO implemented the natural gas distribution rates approved by the PAPUC in its settlement of the 2008 natural gas distribution rate case that provided for an additional $77 million of revenue annually. In December 2010, the PAPUC approved a settlement of PECO's natural gas distribution rate case filed in August 2010 that provides an increase in annual revenue of $20 million. The approved natural gas distribution rates became effective on January 1, 2011.

See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Construction Budget

PECO's business is capital intensive and requires significant investments primarily in energy transmission and distribution facilities to ensure the adequate capacity, reliability and efficiency of its system. Based on PJM's RTEP, PECO has various construction commitments, including costs related to transmission system reliability upgrades due to Generation's plant retirements, as discussed in Notes 14 and 18 of the Combined Notes to Consolidated Financial Statements. PECO's most recent estimate of capital expenditures for plant additions and improvements for 2011 is $450 million, which includes capital expenditures related to the smart meter program and SGIG project net of DOE expected reimbursements.

ComEd and PECO

Transmission Services

ComEd and PECO provide unbundled transmission service under rates established by FERC. FERC has used its regulation of transmission to encourage competition for wholesale generation services and the development of regional structures to facilitate regional wholesale markets. Under FERC's open access transmission policy promulgated in Order No. 888, ComEd and PECO, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates. ComEd and PECO are required to comply with FERC's Standards of Conduct regulation, as amended, governing the communication of non-public information between the transmission owner's employees and wholesale merchant employees.

PJM is the ISO and the FERC-approved RTO for the Mid-Atlantic and Midwest regions. PJM is the transmission provider under, and the administrator of, the PJM Open Access Transmission Tariff (PJM Tariff), operates the PJM energy, capacity and other markets, and, through central dispatch, controls the day-to-day operations of the bulk power system for the PJM region. ComEd and PECO are members of PJM and provide regional transmission service pursuant to the PJM Tariff. ComEd, PECO and the other transmission owners in PJM have turned over control of their transmission facilities to PJM, and their transmission systems are currently under the dispatch control of PJM. Under the PJM Tariff, transmission service is provided on a region-wide, open-access basis using the transmission facilities of the PJM members at rates based on the costs of transmission service.

ComEd's transmission rates are established based on a formula that was approved by FERC in January 2008. FERC's order establishes the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

As a result of PECO's 1998 restructuring settlement, retail transmission rates were capped at the level in effect on December 31, 1996, which remained unchanged through December 31, 2010. PECO's transmission rate included in the PJM Open Access Transmission Tariff is a FERC-approved rate. This is the rate that all load serving entities in the PECO transmission zone pay for transmission service. PECO's 2010 electric distribution rate case settlement provided for recovery of PJM transmission network service charges and RTEP charges from default service customers, on a full and current basis through a rider.

See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information regarding transmission services.

Environmental Regulation

General

Exelon, Generation, ComEd and PECO are subject to environmental regulation administered by the U.S. EPA and various state and local environmental protection agencies or boards. State and local regulation includes the authority to regulate air, water and noise emissions and solid waste disposals. The Registrants are also subject to legislation regarding environmental matters by the United States Congress and by various state and local jurisdictions where the Registrants operate their facilities.

The Exelon board of directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental matters, including the CEO who also serves as Exelon's Chief Environmental Officer; the Vice President, Corporate Strategy and Exelon 2020; the Corporate Environmental Strategy Director and the Environmental Regulatory Strategy Director, as well as senior management of Generation, ComEd and PECO. Performance for those individuals directly involved in environmental strategy activities is reviewed and affects compensation as part of the annual individual performance review process. The Exelon board has delegated to its corporate governance committee authority to oversee Exelon's strategies and efforts to protect and improve the quality of the environment, including, but not limited to, Exelon's climate change and sustainability policies and programs, and Exelon 2020, Exelon's comprehensive business and environmental plan, as discussed in further detail below. The Exelon board has also delegated to its generation oversight committee authority to oversee environmental, health and safety issues relating to Generation, and to its energy delivery oversight committee authority to oversee environmental, health and safety issues related to ComEd, PECO and Exelon Transmission Company.

Water

Under the Federal Clean Water Act (Clean Water Act), NPDES permits for discharges into waterways are required to be obtained from the U.S. EPA or from the state environmental agency to which the permit program has been delegated and must be renewed periodically. All of Generation's power generation facilities discharge industrial wastewater into waterways and are therefore subject to these regulations and operate under NPDES permits or pending applications for renewals of such permits after being granted an administrative extension.

See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information regarding the impact to Exelon of state permitting agencies' administration of the Phase II rule implementing Section 316(b) of the Clean Water Act, as well as the planned cessation of generation operations at Oyster Creek.

Generation is also subject to the jurisdiction of certain other state and regional agencies and I compacts, including the Delaware River Basin Commission and the Susquehanna River Basin I Commission.

Solid and Hazardous Waste

The CERCLA, as amended, provides for immediate response and removal actions coordinated by the U.S. EPA in the event of threatened releases of hazardous substances into the environment and authorizes the U.S. Government either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of waste at sites, most of which are listed by the U.S. EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with a U.S. EPA-directed cleanup, may voluntarily settle with the U.S. Government concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight prior to listing on the NPL. Various states, including Illinois and Pennsylvania, have also enacted statutes that contain provisions substantially similar to CERCLA. In addition, the RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

Generation, ComEd and PECO and their subsidiaries are or are likely to become parties to proceedings initiated by the U.S. EPA, state agencies and/or other responsible parties under CERCLA and RCRA with respect to a number of sites, including MGP sites, or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third party.

Environmental Remediation

ComEd's and PECO's environmental liabilities primarily arise from contamination at former MGP sites. MGPs manufactured gas in Illinois and Pennsylvania from approximately 1850 to the 1950s. ComEd and PECO generally did not operate MGPs as corporate entities but did acquire MGP sites as part of the absorption of smaller utilities, for which they may be liable for environmental remediation. ComEd, pursuant to an ICC order, and PECO, pursuant to the joint settlements of the 2008 and 2010 natural gas distribution rate cases, are recovering environmental remediation costs of the MGP sites through a provision within customer rates. PECO's 2010 natural gas distribution rate case increased the annual MGP recovery to be collected from customers beginning in January 2011.

The amount to be expended in 2011 at Exelon for compliance with environmental remediation is expected to total $23 million, consisting of $17 million and $6 million at ComEd and PECO, respectively. In addition, Generation, ComEd and PECO may be required to make significant additional expenditures not presently determinable.

See Notes 2 and 18 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' environmental remediation efforts and related impacts to the Registrants' results of operations, cash flows and financial position.

Air

Air quality regulations promulgated by the U.S. EPA and the various state and local environmental agencies in Illinois, Massachusetts, Pennsylvania and Texas in accordance with the Federal Clean Air Act and the Clean Air Act Amendments of 1990 (Amendments) impose restrictions on emission of particulates, sulfur dioxide (SO_2), nitrogen oxides (NO_X), mercury and other pollutants and require permits for operation of emissions sources. Such permits have been obtained by Exelon's subsidiaries and must be renewed periodically. The Amendments establish a comprehensive and complex national program to substantially reduce air pollution, including a two-phase program to reduce acid rain effects by significantly reducing emissions of SO_2 and NO_X from power plants. Flue-gas desulfurization systems (SO_2 scrubbers) have been installed at all of Generation's coal-fired units.

See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information regarding clean air regulation and legislation in the forms of the proposed Transport Rule, the regulation of hazardous air pollutants from fossil generating stations, and regulation of GHG emissions, in addition to NOVs issued to Generation and ComEd for alleged violations of the Clean Air Act.

Global Climate Change

Exelon believes the evidence of global climate change is compelling and that the energy industry, though not alone, is a significant contributor to the human-caused emissions of GHGs that many in the scientific community believe contribute to global climate change, as reported by the National Academy of Sciences in May 2010. Exelon, as a producer of electricity from predominantly low-carbon generating facilities (such as nuclear, wind and hydroelectric), has a relatively small GHG emission profile, or carbon footprint, compared to other domestic generators of electricity. By virtue of its significant investment in low-carbon intensity assets, Generation's emission intensity, or rate of carbon dioxide equivalent (CO_2e) emitted per unit of electricity generated, is among the lowest in the industry. Exelon does produce GHG emissions, primarily at its fossil fuel-fired generating plants; CO_2, methane and nitrous oxide are all emitted in this process, with CO_2 representing the largest portion of these GHG emissions. GHG emissions from Generation's combustion of fossil fuels represent approximately 90% of Exelon's total GHG emissions. However, only approximately 6% of Exelon's total electric supply is provided by its fossil fuel generating plants. Other GHG emission sources at Exelon include natural gas (methane) leakage on the gas pipeline system and the coal piles at its generating plants, sulfur hexafluoride (SF_6) leakage in its electric operations and refrigerant leakage from its chilling and cooling equipment as well as fossil fuel combustion in its motor vehicles and usage of electricity in its facilities. Despite its small carbon footprint, Exelon believes its operations could be significantly affected by the possible physical risks of climate change and by mandatory programs to reduce GHG emissions. See Item 1A. Risk Factors of Exelon's 2010 Form 10-K for information regarding the market and financial, regulatory and legislative, and operational risks associated with climate change.

Climate Change Regulation. Exelon is, or may become, subject to climate change regulation or legislation at the international, Federal, regional and state levels.

International Climate Change Regulation. At the international level, the United States is currently not a party to the Kyoto Protocol, which is a protocol to the United Nations Framework Convention on Climate Change (UNFCCC) and became effective for signatories on February 16, 2005. The United Nations' Kyoto Protocol process generally requires developed countries to cap GHG emissions at certain levels during the 2008-2012 time period. At the conclusion of the December 2007 United Nations Climate Change Conference in Bali, Indonesia, the Bali Action Plan was adopted, which identifies a work group, process and timeline for the consideration of possible post-2012 international actions to further address climate change. In December 2009, the United States agreed to the non-binding Copenhagen Accord at the conclusion of the 15th Conference of the Parties under the UNFCCC. Under the Copenhagen Accord, the United States agreed to undertake a number of voluntary measures, including the establishment of a goal to reduce GHG emissions and contributions toward a fund to assist developing nations to address their GHG emissions. The Conference of the Parties met in Mexico in December 2010 and while some progress was made in the Cancun Agreement, the fundamental issues around GHG emission reductions and a successor to the Kyoto Protocol remain unresolved. The next Conference of the Parties meeting will be held in December 2011 in South Africa.

Federal Climate Change Legislation and Regulation. Various stakeholders, including Exelon, legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors are considering ways to address the climate change issue. Mandatory programs to reduce GHG emissions are likely to evolve in the future. If these programs become effective, Exelon may incur costs either to further limit or offset the GHG emissions from its operations or procure emission allowances or credits.

Numerous bills were introduced in Congress during the 111th Congress that address climate change from different perspectives, including direct regulation of GHG emissions and the establishment of Federal Renewable Portfolio Standards, but none were passed by both houses of Congress. Exelon supports the enactment, through Federal legislation, of a cap-and-trade program for GHG emissions that is mandatory, economy-wide and designed in a way to limit potential harm to the economy and protect consumers. Exelon believes that any mechanism for allocation of GHG emission allowances should include significant free grants of allowances to electric (and potentially gas) distribution companies to help offset the cost impact of GHG regulation to the end-use consumer. Over the last few years, Exelon has worked with other businesses and environmental organizations that participate in the United States Climate Action Partnership to support the development of an integrated package of recommendations for the Federal government to address the climate change issue through Federal legislation, including aggressive emission reduction targets for total U.S. emissions and robust cost containment measures to ensure that program costs are reasonable. In reaction to the U.S. EPA's proposed regulation of GHG emissions, various bills have been introduced in the U.S. House of Representatives that would prohibit or impede the U.S. EPA's rulemaking efforts. The timing of the consideration of such legislation is unknown.

The issue of GHG regulation of stationary sources will likely be addressed either under the existing provisions of the Clean Air Act by U.S. EPA regulation, or by new and comprehensive Federal legislation. The Obama administration and the U.S. EPA have stated a preference for addressing the issue through Federal legislation. The extent to which GHG emissions will be regulated is currently unknown; however, potential regulation of GHG emissions from stationary sources could cause Exelon to incur material costs of compliance.

Regional and State Climate Change Legislation and Regulation. At a regional level, on November 15, 2007, six Midwest state Governors (Illinois, Iowa, Kansas, Michigan, Minnesota and Wisconsin) signed the Midwestern Greenhouse Gas Accord. Under that

Accord, an inter-state work group was formed to establish a Midwestern GHG Reduction Program that will: (1) establish GHG reduction targets and timeframes consistent with member state targets; (2) develop a market-based and multi-sector cap-and-trade program to help achieve GHG reductions; and (3) develop other mechanisms and policies to assist in meeting GHG reduction targets (e.g. a low carbon fuel standard). In May 2010, an advisory group appointed by the Governors issued recommendations, but no actions have been taken on the recommendations.

At the state level, the PCCA was signed into law in Pennsylvania in July 2008. The PCCA requires, among other things, that: a Climate Change Advisory Committee be formed; a report on the potential impact of climate change in Pennsylvania be developed; the PA DEP develop a GHG inventory for Pennsylvania; a voluntary GHG registry be identified; and the PA DEP, in consultation with the Climate Change Advisory Committee, develop a Climate Change Action Plan for Pennsylvania to be reviewed with the Pennsylvania General Assembly. The Climate Change Advisory Committee issued its recommendations for an Action Plan for consideration by the Pennsylvania legislature on October 9, 2009.

Exelon's Voluntary Climate Change Efforts. In a world increasingly concerned about global climate change, nuclear power as well as other virtually non-GHG emitting power will play a pivotal role. As a result, Exelon's low-carbon generating fleet is seen by management as a competitive advantage. Exelon believes that the significance of its low GHG emission profile can only grow as policymakers take action to address global climate change.

Despite Exelon's low GHG emission inventory and the absence of a mandatory national program in the United States, Exelon is actively engaged in voluntary reduction efforts. Exelon made a voluntary commitment in 2005 under the U.S. EPA's Climate Leaders Program to reduce its GHG emissions by 8% from 2001 levels by the end of 2008. Exelon achieved this goal by reducing its carbon dioxide-equivalent (CO_2e) emissions to 9.7 million metric tons in 2008, from a 2001 baseline of 15.7 million metric tons. This was accomplished through the retirement of older, inefficient fossil power plants, reduced leakage of SF_6, increased use of renewable energy and energy efficiency initiatives.

In 2008, Exelon expanded its commitment to GHG reduction with the announcement of a comprehensive business and environmental strategic plan. The plan, Exelon 2020, details an enterprise-wide strategy and a wide range of initiatives being pursued by Exelon to reduce Exelon's GHG emissions and those of its customers, communities, suppliers and markets. Exelon 2020 sets a goal for Exelon to reduce, offset, or displace more than 15 million metric tons of GHG emissions per year by 2020 (from 2001 levels).

Through Exelon 2020, Exelon is pursuing three broad strategies: reducing or offsetting its own carbon footprint, helping customers and communities reduce their GHG emissions, and offering more low-carbon electricity in the marketplace. In 2010, Exelon announced that it had achieved just over 50% of the annual Exelon 2020 goal. The planned retirement of fossil units, Cromby Units 1 and 2 and Eddystone Unit 1 in 2011 and Eddystone Unit 2 in 2012, will further contribute to fully achieving the goal. The early retirement of Oyster Creek may result in increased generation from fossil generating plants in the PJM RTO, which could result in increased GHG emissions under Exelon 2020 through reverse displacement. The current plan for achieving the Exelon 2020 goal accounts for these events. Initiatives to reduce Exelon's own carbon footprint include reducing building energy consumption by 25%, reducing vehicle fleet emissions, improving the efficiency of the generation and delivery system for electricity and natural gas, and developing an industry-leading green supply chain. Plans to help customers reduce their GHG emissions include ComEd's Smart Ideas portfolio of energy efficiency programs, a similar portfolio of energy efficiency programs at PECO to meet the requirements of Act 129, the implementation of smart-meters and real-time pricing programs and a broad array of communication initiatives to increase customer awareness of approaches to manage their energy consumption. See Note 2 of the Combined Notes to Consolidated Financial Statements for further information regarding ComEd and PECO smart grid filings and stimulus grant awards. Finally, Exelon will offer more low-carbon electricity in the marketplace by increasing its investment in renewable power and adding capacity to existing nuclear plants through uprates.

Exelon has incorporated Exelon 2020 into its overall business plans and has an organized implementation effort underway. This implementation effort includes a periodic review and refinement of Exelon 2020 initiatives in light of changing market conditions. Specific initiatives and the amount of expenditures to implement the plan will depend on economic and policy developments, and will be made on a project-by-project basis in accordance with Exelon's normal project evaluation standards. As further legislation and regulation imposing requirements on emissions of air pollutants are promulgated, Exelon's emissions reduction efforts will position the company to benefit from the long-term positive impact of the requirements on capacity and energy prices while minimizing the impact of costs of compliance on Exelon's operations, cash flows or financial position.

The Exelon 2020 strategy is reviewed annually and updated to reflect changes in the market, regulations, technology and other factors that affect the merit of various GHG abatement options. In spite of the recent economic downturn, the decline in wholesale power prices and the uncertainty of Federal climate policy, Exelon 2020 has been demonstrated to be a sustainable business strategy.

Renewable and Alternative Energy Portfolio Standards

Thirty-three states have adopted some form of RPS requirement. As previously described, Illinois and Pennsylvania have laws specifically addressing energy efficiency and renewable energy initiatives. In addition to state level activity, RPS legislation has been considered and may be considered again in the future by the United States Congress. Also, states that currently do not have RPS requirements may determine to adopt such legislation in the future.

The Illinois Settlement Legislation required that procurement plans implemented by electric utilities include cost-effective renewable energy resources or approved equivalents such as RECs in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers by June 1, 2008, increasing to 10% by June 1, 2015, with a goal of 25% by June 1, 2025. Utilities are allowed to pass-through any costs from the procurement of these renewable resources or approved equivalents subject to legislated rate impact criteria. As of December 31, 2010, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. See Note 2 and Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.

The AEPS Act is effective for PECO beginning in 2011, following the expiration of PECO's transition period. During 2011, PECO will be required to supply approximately 3.5% and 6.2% of electric energy generated from Tier I (including solar, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, fuel cells, biomass energy, coal mine methane and black liquor generated within Pennsylvania) and Tier II (including waste coal, demand-side management, large-scale hydropower, municipal solid waste, generation of electricity utilizing by-products of the pulping process and wood, distributed generation systems and integrated combined coal gasification technology) alternative energy resources, respectively, as measured in AECs. The compliance requirements will incrementally escalate to 8.0% for Tier I and 10.0% for Tier II by 2021. In order to prepare for the first year of required compliance, PECO procured and banked AECs in accordance with their PAPUC-approved plan over the past three years. PECO has entered into five-year agreements and ten-year agreements with accepted bidders, including Generation, to purchase annually 452,000 non-solar and 8,000 solar Tier 1 AECs, respectively. PECO also purchases AECs through its DSP Program full requirement contracts. In November 2010, PECO filed a petition with the PAPUC for approval to procure Tier II AECs to satisfy PECO's compliance requirements for the AEPS reporting years ending 2011 and 2012.

Similar to ComEd and PECO, Generation's retail electric business must source a portion of the electric load it serves in IL and PA from renewable resources or approved equivalents such as RECs. While Generation is not directly affected by RPS or AEPS legislation from a compliance perspective, potential regulation and legislation regarding renewable and alternative energy resources could increase the pace of development of wind and other renewable/alternative energy resources, which could put downward pressure on wholesale market prices for electricity in some markets where Exelon operates generation assets. At the same time, such developments may present some opportunities for sales of Generation's renewable power, including from Exelon Wind, Generation's hydroelectric and landfill gas generating stations and wind energy PPAs.

See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

(Dollars in millions except per share data, unless otherwise noted)

MARKET FOR OUR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Exelon's common stock is listed on the New York Stock Exchange. As of January 31, 2011, there were 661,862,913 shares of common stock outstanding and approximately 130,323 record holders of common stock.

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

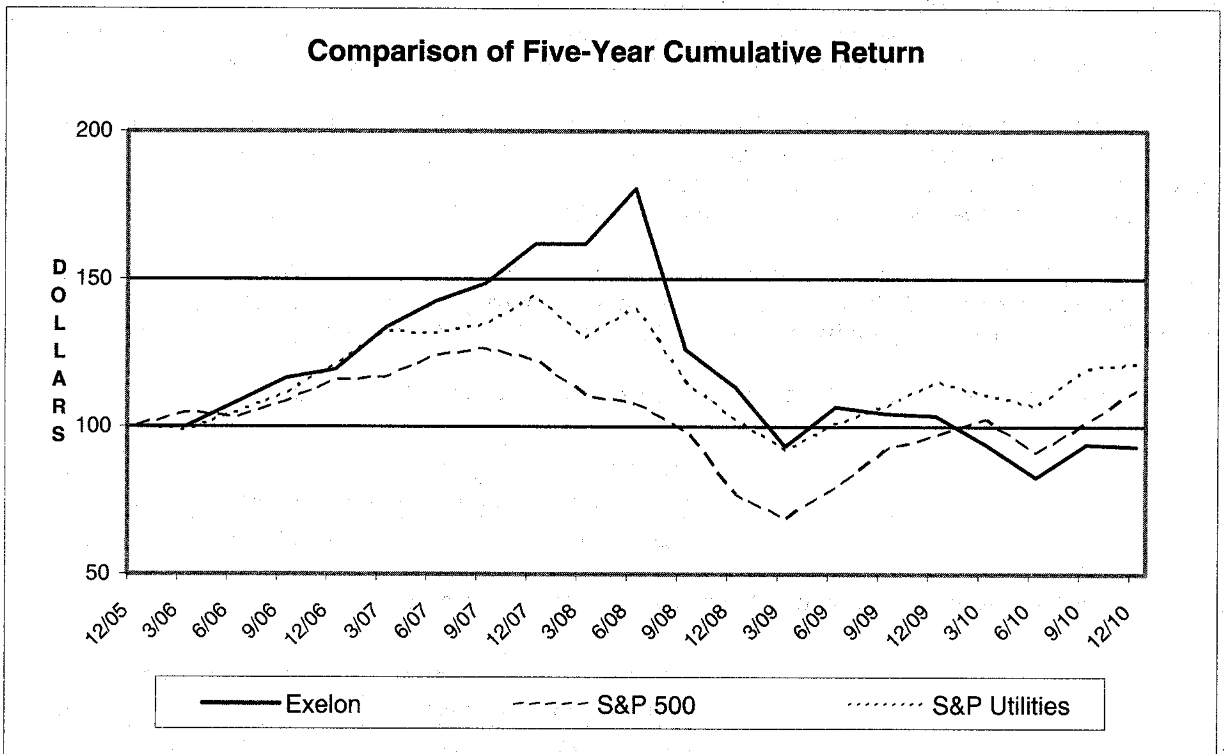
	2010				2009			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$44.49	$43.32	$45.10	$49.88	$51.98	$54.47	$51.46	$58.98
Low price	39.05	37.63	37.24	42.97	45.90	47.30	44.24	38.41
Close	41.64	42.58	37.97	43.81	48.87	49.62	50.12	45.39
Dividends	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525

Stock Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in Exelon common stock, as compared with the S&P 500 Stock Index and the S&P Utility Index for the period 2006 through 2010.

This performance chart assumes:

- $100 invested on December 31, 2005 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and
- All dividends are reinvested.



	Value of Investment at December 31,					
	2005	2006	2007	2008	2009	2010
Exelon Corporation	$100.00	$119.72	$161.70	$113.39	$104.02	$93.21
S&P 500	$100.00	$115.76	$122.11	$77.00	$97.31	$111.95
S&P Utilities	$100.00	$120.96	$144.35	$102.59	$114.71	$120.95

Source: Bloomberg

Dividends

Under applicable Federal law, Generation, ComEd and PECO can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Generation, ComEd or PECO may limit the dividends that these companies can distribute to Exelon.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." What constitutes "funds properly included in capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon's actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with financings arranged through ComEd Financing III that it will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued.

PECO's Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. At December 31, 2010, such capital was $2.9 billion and amounted to about 33 times the liquidating value of the outstanding preferred securities of $87 million.

PECO may not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued.

At December 31, 2010, Exelon had retained earnings of $9,304 million, including Generation's undistributed earnings of $2,633 million, ComEd's retained earnings of $331 million consisting of retained earnings appropriated for future dividends of $1,970 million, partially offset by $1,639 million of unappropriated retained deficits, and PECO's retained earnings of $522 million.

The following table sets forth Exelon's quarterly cash dividends per share paid during 2010 and 2009:

	2010				2009			
(per share)	**4th Quarter**	**3rd Quarter**	**2nd Quarter**	**1st Quarter**	**4th Quarter**	**3rd Quarter**	**2nd Quarter**	**1st Quarter**
Exelon	$0.525	$0.525	$0.525	$0.525	$0.525	$0.525	$0.525	$0.525

The following table sets forth Generation's quarterly distributions and ComEd's and PECO's quarterly common dividend payments:

	2010				2009			
(in millions)	**4th Quarter**	**3rd Quarter**	**2nd Quarter**	**1st Quarter**	**4th Quarter**	**3rd Quarter**	**2nd Quarter**	**1st Quarter**
Generation	$885	$206	$156	$261	$475	$1,126	$396	$279
ComEd	85	75	75	75	60	60	60	60
PECO	46	63	51	64	65	93	67	87

On January 25, 2011, the Exelon Board of Directors declared a regular quarterly dividend of $0.525 per share on Exelon's common stock. The dividend is payable on March 10, 2011, to shareholders of record of Exelon at the end of the day on February 15, 2011.

SELECTED FINANCIAL DATA

The selected financial data presented below has been derived from the audited consolidated financial statements of Exelon. This data is qualified in its entirety by reference to and should be read in conjunction with Exelon's Consolidated Financial Statements and Management's Discussion and Analysis of Financial Condition and Results of Operations included in this Financial Information supplement.

in millions, except for per share data	For the Years Ended December 31, 2010	2009	2008	2007	2006
Statement of Operations data:					
Operating revenues	$18,644	$17,318	$18,859	$18,916	$15,655
Operating income	4,726	4,750	5,299	4,668	3,521
Income from continuing operations	$ 2,563	$ 2,706	$ 2,717	$ 2,726	$ 1,590
Income from discontinued operations	—	1	20	10	2
Net income [(a)]	$ 2,563	$ 2,707	$ 2,737	$ 2,736	$ 1,592
Earnings per average common share (diluted):					
Income from continuing operations	$ 3.87	$ 4.09	$ 4.10	$ 4.03	$ 2.35
Income from discontinued operations	—	—	0.03	0.02	—
Net income	$ 3.87	$ 4.09	$ 4.13	$ 4.05	$ 2.35
Dividends per common share	$ 2.10	$ 2.10	$ 2.03	$ 1.76	$ 1.60
Average shares of common stock outstanding—diluted	663	662	662	676	676

(a) The year 2006 reflects the impact of a goodwill impairment charge of $776 million.

in millions	December 31, 2010	2009	2008 [(a)]	2007 [(a)(b)]	2006 [(a)(b)]
Balance Sheet data:					
Current assets	$ 6,398	$ 5,441	$ 5,130	$ 4,416	$ 4,130
Property, plant and equipment, net	29,941	27,341	25,813	24,153	22,775
Noncurrent regulatory assets	4,140	4,872	5,940	5,133	5,808
Goodwill	2,625	2,625	2,625	2,625	2,694
Other deferred debits and other assets	9,136	8,901	8,038	8,760	7,933
Total assets	$52,240	$49,180	$47,546	$45,087	$43,340
Current liabilities	$ 4,240	$ 4,238	$ 3,811	$ 5,466	$ 4,871
Long-term debt, including long-term debt to financing trusts	12,004	11,385	12,592	11,965	11,911
Noncurrent regulatory liabilities	3,555	3,492	2,520	3,301	3,025
Other deferred credits and other liabilities	18,791	17,338	17,489	14,131	13,439
Preferred securities of subsidiary	87	87	87	87	87
Noncontrolling interest	3	—	—	—	—
Shareholders' equity	13,560	12,640	11,047	10,137	10,007
Total liabilities and shareholders' equity	$52,240	$49,180	$47,546	$45,087	$43,340

(a) Exelon retrospectively reclassified certain assets and liabilities with respect to option premiums into the mark-to-market net asset and liability accounts to conform to the current year presentation.

(b) Exelon retrospectively reclassified certain assets and liabilities in accordance with the applicable authoritative guidance for offsetting amounts related to qualifying derivative contracts.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Exelon

General

Exelon, a utility services holding company, operates through the following principal subsidiaries each of which is treated as a reportable segment:

- *Generation,* whose business consists of its owned and contracted electric generating facilities, its wholesale energy marketing operations and competitive retail sales operations.
- *ComEd,* whose business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution services in northern Illinois, including the City of Chicago.
- *PECO,* whose business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution services in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.

See Note 20 of the Combined Notes to Consolidated Financial Statements for segment information.

Through its business services subsidiary BSC, Exelon provides its subsidiaries with a variety of support services at cost. The costs of these services are directly charged or allocated to the applicable business segments. Additionally, the results of Exelon's corporate operations include costs for corporate governance and interest costs and income from various investment and financing activities.

Exelon Corporation

Executive Overview

Financial Results. All amounts presented below are before the impact of income taxes, except as noted.

Exelon's net income was $2,563 million for the twelve months ended December 31, 2010 as compared to $2,707 million for the twelve months ended December 31, 2009, and diluted earnings per average common share were $3.87 for the twelve months ended December 31, 2010 as compared to $4.09 for the twelve months ended December 31, 2009.

Revenue net of purchased power and fuel expense, which is a non-GAAP measure as discussed below, increased by $172 million primarily due to increased revenues of $201 million at Generation largely related to favorable capacity pricing in the Midwest and Mid-Atlantic regions. Exelon's results were also affected by the impact of favorable weather conditions of $168 million in the ComEd and PECO service territories and a decrease in costs of $84 million associated with the Illinois Settlement Legislation, primarily at Generation. Further, revenues at the utility companies increased by $92 million to recover the costs of regulatory required programs, which are offset in operating expenses, and ComEd recognized recovery of $59 million from customers associated with its uncollectible accounts rider mechanism. Offsetting these favorable impacts were unfavorable market and portfolio conditions of $174 million, increased nuclear fuel costs of $115 million, a reduction of $95 million in mark-to-market gains from Generation's hedging activities in 2010 compared to 2009 and a $57 million impairment of SO_2 emissions allowances related to the U.S. EPA's proposed Transport Rule.

Operating and maintenance expense decreased by $75 million primarily due to the impact of 2009 activities, including the $223 million impairment of the Handley and Mountain Creek stations in 2009 and reduced stock compensation costs in 2010 of $40 million across the operating companies. Decreased operating and maintenance expense was partially offset by higher costs at the utility companies associated with regulatory required programs of $84 million, which are offset in revenue net of purchased power expense, a 2009 reduction in Generation's ARO of $51 million and incremental costs of $42 million related to storms in the ComEd and PECO service territories.

Depreciation and amortization expense increased by $241 million primarily due to increased depreciation expense of $144 million related to ongoing capital expenditures and the change in estimated useful lives associated with the plants subject to shutdowns announced in December 2009 and a scheduled increase in CTC amortization expense at PECO of $98 million in connection with the end of the transition period in accordance with its 1998 restructuring settlement. Exelon's results were also significantly affected by

$120 million in 2009 expenses related to debt extinguishment costs resulting from a 2009 debt refinancing, and by lower net NDT gains of $102 million in 2010 for Non-Regulatory Agreement Units as a result of less favorable market performance.

Exelon results for the twelve months ended December 31, 2010 were negatively affected by certain income tax-related matters. Exelon recorded a non-cash charge of $65 million (after tax) in 2010 and a non-cash gain of $66 million (after tax) in 2009 for the remeasurement of income tax uncertainties. Exelon also recorded a $65 million (after tax) charge to income tax expense as a result of health care legislation passed in March 2010 that includes a provision that reduces the deductibility of retiree prescription drug benefits for Federal income tax purposes.

For further detail regarding the financial results for the years ended December 31, 2010 and 2009, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings. Exelon's adjusted (non-GAAP) operating earnings for the twelve months ended December 31, 2010 were $2,689 million, or $4.06 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,723 million, or $4.12 per diluted share, for the same period in 2009. In addition to net income, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the year ended December 31, 2010 as compared to 2009:

	December 31,			
	2010		2009	
(All amounts after tax; in millions, except per share amounts)		**Earnings per Diluted Share**		**Earnings per Diluted Share**
Net Income	$2,563	$ 3.87	$2,707	$ 4.09
Illinois Settlement Legislation [(a)]	13	0.02	66	0.10
Mark-to-Market Impact of Economic Hedging Activities [(b)]	(52)	(0.08)	(110)	(0.16)
Unrealized Gains Related to NDT Fund Investments [(c)]	(52)	(0.08)	(132)	(0.19)
Retirement of Fossil Generating Units [(d)]	50	0.08	34	0.05
Impairment of Certain Emissions Allowances [(e)]	35	0.05	—	—
John Deere Renewables, LLC Acquisition Costs [(f)]	7	0.01	—	—
Asset Retirement Obligation Reduction [(g)]	(7)	(0.01)	(32)	(0.05)
NRG Energy, Inc. Acquisition Costs [(h)]	—	—	20	0.03
2009 Restructuring Charges [(i)]	—	—	22	0.03
Costs Associated with Early Debt Retirements [(j)]	—	—	74	0.11
City of Chicago Settlement with ComEd [(k)]	2	—	5	0.01
Non-Cash Charge Resulting From Health Care Legislation [(l)]	65	0.10	—	—
Non-Cash Remeasurement of Income Tax Uncertainties and Reassessment of State Deferred Income Taxes [(m)]	65	0.10	(66)	(0.10)
Impairment of Certain Generating Assets [(n)]	—	—	135	0.20
Adjusted (non-GAAP) Operating Earnings	**$2,689**	**$ 4.06**	**$2,723**	**$ 4.12**

(a) Reflects credits issued by Generation and ComEd for the years ended December 31, 2010 and 2009, respectively, as a result of the Illinois Settlement Legislation (net of taxes of $9 million and $42 million, respectively). See Note 2 of the Combined Notes to the Consolidated Financial Statements for additional detail related to Generation's and ComEd's rate relief commitments.

(b) Reflects the impact of (gains) for the years ended December 31, 2010 and 2009, respectively, on Generation's economic hedging activities (net of taxes $(34) million and $(71) million, respectively). See Note 9 of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.
(c) Reflects the impact of (gains) for the years ended December 31, 2010 and 2009, respectively, on Generation's NDT fund investments for Non-Regulatory Agreement Units (net of taxes of $(41) million and $(95) million, respectively). See Note 12 of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.
(d) Primarily reflects accelerated depreciation, inventory write-downs and severance costs for the years ended December 31, 2010 and 2009, respectively, associated with the planned retirement of four fossil generating units (net of taxes of $32 million and $22 million, respectively). See Note 14 of the Combined Notes to Consolidated Financial Statements and "Results of Operations—Generation" for additional detail related to the generating unit retirements.
(e) Reflects the impairment of certain SO_2 emissions allowances in the third quarter of 2010 as a result of declining market prices since the release of the EPA's proposed Transport Rule (net of taxes of $22 million). See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.
(f) Reflects external costs incurred for the year ended December 31, 2010 associated with Exelon's acquisition of John Deere Renewables, LLC (net of taxes of $4 million), now known as Exelon Wind. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.
(g) Reflects the income statement impact for the years ended December 31, 2010 and 2009, respectively, primarily related to the reduction in the asset retirement obligations at ComEd and PECO in December 31, 2010 (net of taxes of $(4) million) and the annual update of Generation's decommissioning obligation in 2009 (net of taxes of $(20) million).
(h) Reflects external costs incurred for the year ended December 31, 2009, associated with Exelon's proposed acquisition of NRG Energy, Inc., which was terminated in July 2009 (net of taxes of $14 million).
(i) Reflects the impact in 2009 of the elimination of management and staff positions (net of taxes of $(14) million).
(j) Reflects costs for the year ended December 31, 2009 associated with early debt retirements at Generation and Exelon Corporate (net of taxes of $47 million).
(k) Reflects costs for the years ended December 31, 2010 and 2009, respectively, associated with ComEd's 2007 settlement agreement with the City of Chicago (net of taxes of $1 million and $3 million, respectively).
(l) Reflects a non-cash charge to income taxes related to the passage of Federal health care legislation, which includes a provision that reduces the deductibility, for Federal income tax purposes, of retiree prescription drug benefits for Federal income tax purposes to the extent they are reimbursed under Medicare Part D. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional detail related to the impact of the health care legislation.
(m) Reflects the impacts of 2009 and 2010 remeasurements of income tax uncertainties and a 2009 change in state deferred income tax rates (net of taxes on interest expense of $41 million and $23 million). See Note 11 of the Combined Notes to Consolidated Financial Statements for additional detail.
(n) Reflects the impairment of the Handley and Mountain Creek stations recorded during the first quarter of 2009 (net of taxes of $87 million). See "Results of Operations—Generation" for additional detail related to asset impairments.

Outlook for 2011 and Beyond.

Economic and Market Conditions

Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular, the prices of natural gas and coal, which drive the wholesale market prices that Generation's nuclear power plants can command, (2) the rate of expansion of subsidized low carbon generation such as wind energy in the markets in which Generation's output is sold, (3) the impacts on energy demand of factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) regulatory and legislative actions, such as the proposed U.S. EPA Transport Rule and the New Jersey capacity legislation. See *Environmental Matters* and *Regulatory and Legislative Matters* sections below for further detail on the Transport Rule and New Jersey capacity legislation, respectively.

The use of new technologies to recover natural gas from shale deposits is expected to increase natural gas supply and reserves, which will tend to place downward pressure on natural gas prices and therefore on wholesale power prices, which would mean a reduction in Exelon's revenues.

The market price for electricity is also affected by changes in the demand for electricity. Poorer than expected economic conditions, milder than normal weather and the growth of energy efficiency and demand response programs can depress demand. The result is that higher-cost generating resources do not run as frequently, putting downward pressure on market prices for electricity and/or capacity. The continued sluggish economy in the United States has in fact led to a slow down in the growth of demand for electricity, and ComEd and PECO are projecting load demand to remain flat in 2011 compared to 2010.

Hedging Strategy. Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Although Exelon's hedging policies have helped protect Exelon's earnings as wholesale market prices have declined, sustained increases in natural gas supply and reserve levels, or a slow recovery of the economy, could result in a prolonged depression of or further decline in commodity prices and in long-term sluggish growth in demand.

Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into derivative contracts—including financially-settled swaps, futures contracts and swap options—and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2011 and 2012. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. Generation currently hedges commodity risk on a ratable basis over the three years leading to the spot market. As of December 31, 2010, the percentage of expected generation hedged was 90%-93%, 67%-70% and 32%-35% for 2011, 2012 and 2013, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include cash flow hedges, other derivatives and certain non-derivative contracts including sales to ComEd and PECO to serve their retail load. Generation has been and will continue to be proactive in using hedging strategies to mitigate this price risk in subsequent years as well. The expiration of the PPA with PECO at the end of 2010 will likely result in increases in margins earned by Generation in 2011 for the portion of Generation's electricity portfolio previously sold to PECO under the PPA, however the ultimate impact of entering into new power supply contracts under Generation's three-year ratable hedging program to replace the PPA will depend on a number of factors, including future wholesale market prices, capacity markets, energy demand and the effects of any new applicable Pennsylvania laws and or rules and regulations promulgated by the PAPUC.

Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 57% of Generation's uranium concentrate requirements from 2011 through 2015 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position. Generation uses long-term contracts and financial instruments such as over-the-counter and exchange-traded instruments to mitigate price risk associated with certain commodity price exposures. Both ComEd and PECO mitigate exposure to commodity price risk through the recovery of procurement costs from retail customers.

New Growth Opportunities

Nuclear Uprate Program. During 2009, Generation announced a series of planned power uprates across its nuclear fleet that will result in between 1,300 and 1,500 MW of additional generation capacity within eight years. The uprate projects represent a total investment of approximately $3.65 billion in overnight cost, as measured in 2010 dollars. Using proven technologies, the projects take advantage of new production and measurement technologies, new materials and learning from a half-century of nuclear power operations. Uprate projects, representing approximately 60% of the planned uprate MW, are underway at the Limerick and Peach Bottom nuclear stations in Pennsylvania and the Byron, Braidwood, Dresden, LaSalle and Quad Cities plants in Illinois. The remainder will come from additional projects across Generation's nuclear fleet beginning in 2011 and ending in 2017. At 1,500 nuclear-generated MW, the uprates would displace 8 million metric tons of carbon emissions annually that would otherwise come from burning fossil fuels. The uprates are being undertaken pursuant to an organized, strategically sequenced implementation plan. The implementation effort includes a periodic review and refinement of the project in light of changing market conditions. As part of this periodic review process, the uprate project at Three Mile Island is currently under evaluation. The amount of expenditures to implement the plan ultimately will depend on economic and policy developments, and will be made on a project-by-project basis in accordance with Exelon's normal project evaluation standards. The ability to implement several projects requires the successful resolution of various technical issues. The resolution of these issues may affect the timing and amount of the power increases associated with the power uprate initiative. Through December 31, 2010, Generation had added 101 MWs of nuclear generation through its uprate program, with another 98 MWs scheduled to be added in 2011.

Acquisition of John Deere Renewables. On December 9, 2010, Generation acquired all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind), a leading operator and developer of wind power, for approximately $893 million in cash. Generation acquired 735 MWs of installed, operating wind capacity located in eight states. Approximately 75% of the operating portfolio's expected output is already sold under long-term power purchase arrangements. Additionally, Generation will pay up to $40 million related to three projects with a capacity of 230 MWs which are currently in advanced stages of development, contingent upon meeting certain contractual commitments related to the commencement of construction of each project. This contingent consideration was valued at $32 million of which approximately $16 million has been recorded as a current liability and the remainder has been recorded as a noncurrent liability. As a result, total consideration recorded for the Exelon Wind acquisition was $925 million. Generation also has the opportunity to pursue approximately 1,200 MWs of new wind projects that are in various stages of development. On September 30, 2010, Generation issued $900 million of senior notes whose proceeds were used to fund the acquisition. The acquisition provides incremental earnings starting in 2012 and cash flows starting in 2013 and is a key part of Exelon 2020.

Transmission Development Project. Exelon, Electric Transmission America, LLC (ETA) and AEP Transmission Holding Company, LLC (AEP) have signed a non-binding memorandum of understanding to develop a 420-mile extra high-voltage transmission project from the Ohio border through Indiana to the northern portion of Illinois. The Reliability Interregional Transmission Extension (RITE) Line project is expected to strengthen the high-voltage transmission system and improve overall system reliability. ComEd is expected to lead the building of the Illinois portion of the project. The total cost of the RITE Line project is expected to be approximately $1.6 billion, with the Illinois portion of the line expected to cost approximately $1.2 billion. These costs are expected to be funded by ComEd, Exelon or an affiliate, ETA and AEP. The ultimate cost of the line will be dependent on a number of factors, including RTO requirements, state siting requirements, routing of the line, and equipment and commodity costs. The project will be built in stages over three to four years, likely between 2015 and 2018, and is subject to FERC, PJM and state approvals.

Advanced Metering Infrastructure. On April 22, 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan under which PECO will deploy 600,000 smart meters within three years and deploy smart meters to all of its electric customers over the next 10 years. On April 12, 2010, PECO entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA. Under the SGIG, PECO has been awarded $200 million, the maximum allowable grant under the program, for its SGIG project, Smart Future Greater Philadelphia. The SGIG project has a budget of more than $400 million and includes approximately $7 million related to demonstration projects by two sub-recipients. In total, over the next ten years, PECO is planning to spend up to a total of $650 million on its smart grid and smart meter infrastructure. During 2010, PECO entered into agreements for an AMI network, AMI systems, installation of the first 600,000 meters, and procurement of meters and fiber-cable. The $200 million SGIG from the DOE will be used to reduce the impact of these investments on PECO ratepayers. PECO filed for PAPUC approval of an initial dynamic pricing and customer acceptance program under the Smart Meter Procurement and Installation Plan in October 2010, and plans to file for approval of a universal meter deployment plan for its remaining customers in 2012.

In October 2009, the ICC approved ComEd's proposed AMI pilot program, with minor modifications, and recovery of substantially all program costs from customers. The one-year program was operational in June 2010. The total anticipated cost of the pilot program is approximately $69 million. The AMI pilot program allows ComEd to study the costs and benefits related to automated metering and to develop the cost estimate of potential full system-wide implementation of AMI. In addition, the program allows customers the ability to manage energy use, improve energy efficiency and lower energy bills. Due to an adverse September 30, 2010 Illinois Appellate Court decision, ComEd faces certain cost recovery issues in connection with the pilot program. See Regulatory and Legislative Matters below and Note 2 of the Combined Notes to Consolidated Financial Statements for information on cost recovery issues related to ComEd's AMI pilot program.

Liquidity and Cost Management

Pension Plan Funding. As a result of accelerated cash benefits associated with the Tax Relief Act of 2010, Exelon contributed $2.1 billion to its pension plans in January 2011, representing all currently planned 2011 qualified pension contributions. Exelon's planned funding of these contributions includes $500 million from cash from operations, $750 million from the tax benefits of making the pension contributions and $850 million with the accelerated cash tax benefits from the 100% bonus depreciation provision enacted as part of the Tax Relief Act of 2010. Exelon expects the $2.1 billion contribution, along with other factors, will increase the pension funded status from 71% at December 31, 2010 to 89% at December 31, 2011, subject to actual 2011 asset returns and final actuarial valuations. The $2.1 billion pension contribution will also decrease 2011 pension costs.

Financing Activities. On January 18, 2011, ComEd issued $600 million of 1.625% First Mortgage Bonds due January 15, 2014. The net proceeds of the bonds were used as an interim source of liquidity for the January 2011 contribution to Exelon-sponsored pension plans in which ComEd participates. ComEd anticipates receiving tax refunds as a result of both the pension contribution and the recent Federal tax legislation allowing for accelerated depreciation deductions in 2011 and 2012. As a result, the immediate use of the net proceeds to fund the planned contribution will allow those future cash receipts to be available to fund capital investment and for general corporate purposes.

Credit Facilities. On March 25, 2010, ComEd replaced its $952 million credit facility with a similar $1 billion unsecured revolving credit facility that extends to March 25, 2013. Although the covenants are largely the same as the prior facility, the new facility has higher borrowing costs, reflecting current market pricing. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information regarding those costs. Exelon's, Generation's, and PECO's primary credit facilities largely extend through October 2012. These credit facilities currently provide sufficient liquidity to each of the Registrants. Upon maturity of these credit facilities, Exelon, Generation and PECO may not be able to renew or replace these existing facilities at current terms or commitment levels from banks. Consequently, Exelon, Generation, and PECO may face increased costs for liquidity needs in 2011 and may choose to establish cost-effective alternative liquidity sources as appropriate. Exelon anticipates refinancing these credit facilities, approximately $6.4 billion, in the first half of 2011.

On November 4, 2010, Generation entered into a supplemental credit facility, which provides for an aggregate commitment of up to $300 million. The effectiveness and availability of the credit facility were subject to various conditions, which were satisfied on February 7, 2011. This facility will be primarily used to issue letters of credit. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information regarding this credit facility.

Cost Management. Exelon is committed to operating its businesses responsibly and managing its operating and capital costs in a manner that serves its customers and produces value for its shareholders. Exelon is also committed to an ongoing strategy to make itself more effective, efficient and innovative. Exelon is committed to maintaining a cost control focus and continues to analyze cost trends to identify future cost savings opportunities and implement more planning and performance-measurement tools to allow it to better identify areas for sustainable productivity improvements and cost reductions.

Environmental Matters

Exelon supports the promulgation of environmental regulation by the U.S. EPA, including air, water and waste controls for electric generating units. See discussion below for further details. In addition, Exelon supports comprehensive climate change legislation by the U.S Congress, which includes a mandatory, economy-wide cap-and-trade program for GHG emissions that balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions. Several bills containing provisions for legislation of GHG emissions were introduced in Congress during the 111th Congress, but none were passed by both houses of Congress. In reaction to the U.S. EPA's proposed regulation of GHG emissions, various bills have been introduced in the U.S. House of Representatives that would prohibit or impede the U.S. EPA's rulemaking efforts. The timing of the consideration of such legislation is unknown.

Exelon 2020. In 2008, Exelon expanded its commitment to GHG reduction with the announcement of a comprehensive business and environmental strategic plan, which details an enterprise-wide strategy and a wide range of initiatives being pursued by Exelon to reduce, offset, or displace more than 15 million metric tons of GHG emissions per year by 2020 (from 2001 levels). Exelon has incorporated Exelon 2020 into its overall business plans, and as further legislation and regulation imposing requirements on emissions of air pollutants are promulgated, its emissions reduction efforts will position Exelon to benefit from the long-term positive impact of the requirements on capacity and energy prices while minimizing the impact of costs of compliance on Exelon's operations, cash flows or financial position.

Air. On July 6, 2010, the U.S. EPA published its proposed Transport Rule, which is the first of a number of significant regulations that the U.S. EPA expects to issue that will impose more stringent requirements relating to air, water and waste controls on electric generating units. The air and waste regulations will have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and will likely result in the retirement of older, marginal facilities. Due to its low carbon generation portfolio, Generation will not be significantly directly affected by these regulations, representing a competitive advantage for Generation relative to electric generators that are more reliant on fossil-fuel plants. Upon preliminary review, it is expected that implementation of the proposed Transport Rule regulations will increase power prices over the long term, which would result in a net benefit to Generation's results of operations and cash flows. Exelon filed comments with the U.S. EPA in support of the proposed Transport Rule on October 1, 2010. Extensive comments were filed by the public, both in support of and in opposition to the proposed Transport Rule. The U.S. EPA is reviewing the comments and is scheduled to issue a final rule by the end of the year, to become effective in January 2012.

Beginning with the proposed Transport Rule, the air requirements are expected to be implemented through a series of increasingly stringent regulations relating to conventional air pollutants (e.g., NO_x, SO_2 and particulate matter) as well as HAPs (e.g., acid gases, mercury and other heavy metals) The U.S. EPA has announced that it will complete a review of NAAQS in the 2011 – 2012 timeframe for ozone (nitrogen oxide and volatile organic chemicals), particulate matter, nitrogen dioxide, sulfur dioxide, and lead. This review could result in more stringent emissions limits on fossil-fired electric generating stations. The U.S. EPA is also preparing a proposed rule for a new HAP standard for electric generating units, which is expected to be finalized in the 2011 – 2012 timeframe. The cumulative impact of these regulations could be to require power plant operators to install wet flue gas desulfurization technology for SO_2 and selective catalytic reduction technology for NO_x.

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act, including permitting requirements under the PSD and Title V operating permit sections of the Clean Air Act for new and modified stationary sources that became effective on January 2, 2011, and proposed GHG emissions limitations under the New Source Performance Standards scheduled for finalization in May 2012 pursuant to a litigation settlement.

Water. Following legal challenges to the Phase II rule implementing Section 316(b) of the Clean Water Act, the rule has been withdrawn and remanded to the U.S. EPA for revisions consistent with the courts' decisions. In the interim, Generation has been complying with the requirements of the state permitting agencies, which are administering the rule pursuant to their best professional judgment until a new final rule is issued by the U.S. EPA.

On January 7, 2010, the NJDEP issued a draft NPDES permit for Oyster Creek that would have required, in the exercise of its best professional judgment, the installation of cooling towers as the best technology available within seven years after the effective date of the permit. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. In reliance on that announcement, NJDEP determined that the existing measures at Oyster Creek represent the best technology available for the facility's cooling water intake through the cessation of generation operations. See further discussion of the planned shutdown of Oyster Creek in the "Plant Retirements" section below.

Waste. Under proposed U.S. EPA rules issued on June 21, 2010, coal combustion waste (CCW) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCW either as a hazardous or non-hazardous waste. Under either option, the U.S. EPA's intention is the ultimate elimination of surface impoundments as a waste treatment process. For plants affected by the proposed rules, this would result in significant capital expenditures and variable operating and maintenance expenditures to convert to dry handling and disposal systems and installation of new waste water treatment facilities. Exelon anticipates that the only plants in which it has an ownership interest that would be affected by proposed rules would be Keystone and Conemaugh. As a result, Exelon does not currently expect the adoption of the rules as proposed to have a significant impact on its future capital spending requirements and operating costs. The U.S. EPA has not announced a target date for finalization of the CCW rules.

See Note 18 of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Regulatory and Legislative Matters

Appeal of 2007 Illinois Electric Distribution Rate Case. On September 30, 2010, the Illinois Appellate Court (Court) issued a decision in the appeals related to the ICC's order in ComEd's 2007 electric distribution rate case (2007 Rate Case). That decision ruled against ComEd on the treatment of post-test year accumulated depreciation and the recovery of costs for an AMI/Customer Applications pilot program via a rider (Rider SMP). On November 18, 2010, the Court denied ComEd's petition for rehearing in connection with the September 30, 2010 ruling. On January 25, 2011, ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court. ComEd does not believe any of its other riders are affected by the Court's ruling. See Note 2 of the Combined Notes to Consolidated Financial Statements for further details related to the Court's order.

The following table presents the impacts to Exelon's and ComEd's actual 2010 and estimated 2011 pre-tax earnings resulting from the Court's order.

(Pre-tax in millions)	**Year Ended December 31, 2010**	**1/1/11 - 5/31/11 (a)**
Revenues subject to refund based on Court order (b)	$(17)	$(30)
Reduced pre-tax earnings related to Rider SMP	(1)	(7)
Write-off of Rider SMP regulatory asset	(4)	—

(a) ComEd currently expects new rates will be established in its 2010 distribution rate case no later than June 2011, at which point in time the impacts of the Court's decision should be fully incorporated into ComEd's rates.

(b) The Court also required the ICC to consider whether an additional three months of net pro forma plant investment, beyond what was approved in the ICC order, should be included in rate base. To the extent the ICC allows ComEd to include an additional three months of net plant additions in its revised rates, the pre-tax revenues subject to refund would be reduced by an estimated $12 million in total through the first five months of 2011.

2010 Illinois Electric Distribution Rate Case. On June 30, 2010, ComEd requested ICC approval for an increase of $396 million to its annual delivery services revenue requirement (2010 Rate Case). On January 3, 2011, ComEd filed surrebuttal testimony which adjusted ComEd's requested increase to $326 million to account for recent changes in tax law, corrections, acceptance of limited adjustments proposed by certain parties and the amounts expected to be recovered in the AMI pilot program tariff. The request to increase the annual revenue requirement is to allow ComEd to continue modernizing its electric delivery system and recover the costs of substantial investments made since the last rate filing in 2007. The requested increase also reflects increased costs, most notably pension and OPEB, since ComEd's rates were last determined. The requested increase in electric distribution rates would increase the average residential customer's monthly electric bill by approximately 5%. In addition, ComEd is requesting future recovery of certain amounts that were previously recorded as expense. If that request is approved, ComEd would reverse the previously expensed costs and establish regulatory assets with amortization over the period during which rate recovery is allowed. As a result, ComEd would recognize a one-time benefit of up to $39 million (pre-tax) to reverse the prior charges. The requested increase also includes $22 million for increased uncollectible accounts expense. If the rate request is approved, the threshold for determining over/under recoveries under ComEd's uncollectible accounts tariff would be increased by $22 million.

The Court's September 30, 2010 ruling in connection with the 2007 Rate Case makes it highly unlikely that the ICC would decide the post-test year accumulated depreciation issue in ComEd's favor in the 2010 Rate Case. ComEd estimates that its requested revenue requirement increase of $326 million could be reduced by approximately $85 million as a result of this adjustment. Certain parties have submitted testimony recommending significant reductions to ComEd's requested increase as well as the write-off of certain assets, most notably the regulatory assets associated with severance costs, which was approximately $74 million as of December 31, 2010. Management believes the regulatory asset is appropriate based on the ICC's orders in ComEd's last two distribution rate cases. The new electric distribution rates are expected to take effect no later than June 2011. ComEd cannot predict how much of the requested electric distribution rate increase the ICC may approve. See the discussion of ComEd's 2007 Rate Case above and in Note 2 of the Combined Notes to Consolidated Financial Statements.

Subsequent to the Court's ruling, ComEd filed a request with the ICC to allow it to request recovery, through inclusion in the 2010 Rate Case, of $3 million in operation and maintenance costs, as well as carrying costs associated with capital investment in the ICC-approved AMI/Customer Applications pilot program. The AMI pilot program capital investment had already been requested in rate base in the 2010 Rate Case. On December 2, 2010, the ICC approved ComEd's request. The investment and the pilot program costs are subject to challenge in the 2010 Rate Case proceeding.

ComEd Alternative Regulation Pilot Program. On August 31, 2010, ComEd filed with the ICC an alternative regulation pilot proposal as a companion proposal to its 2010 Rate Case under a provision of the Illinois Public Utility Act that contemplates an alternative regulatory structure. Rather than employing the traditional rate setting process in which the utility seeks recovery of costs already incurred, the proposal, if approved, would bring utilities, stakeholders, and the ICC together to develop, review and approve ongoing investment programs before those investments are made. The pilot process would include a flow-through mechanism to recover the depreciation and the carrying costs associated with an estimated $130 million in capital investments and $65 million in incremental operating and maintenance expense over a two-year period, as incurred. The unrecovered portion of the capital investments would be included in ComEd's rate base in its future delivery services rate case filing. The alternative regulatory structure as proposed by ComEd includes an immediate operating and maintenance savings to customers (up to $2 million) and an incentive mechanism for completing the capital investments under budget. This filing includes a request for approval of the alternative regulatory mechanism as well as approval of costs related to electric vehicles, accelerated reinvestment of urban underground facilities and low income assistance. If the mechanism is approved, ComEd would also seek recovery of an estimated $125 million of smart grid investments after the conclusion of the Illinois Statewide Smart Grid Collaborative workshops, the smart grid policy docket and the evaluation of its AMI pilot program. The ICC is scheduled to issue an order by May 28, 2011.

Proposed Legislation to Modernize Electric Utility Infrastructure and to Update Illinois Ratemaking Process. ComEd and other Illinois utilities and legislators are working to develop legislation that would modernize Illinois' electric grid. The proposal includes a policy-based approach which would provide a more predictable ratemaking system and would enable utilities to modernize the electric grid and set the stage for fostering economic development while creating and retaining jobs. Many other states are changing or are considering changes to the way they regulate utilities in order to improve the predictability of the ratemaking process.

The proposed legislation, which was introduced in the Illinois General Assembly on February 8, 2011, includes a process for determining formula rates that would provide for the recovery of actual costs of service that are prudently incurred and reasonable in amount, reflect the utility's actual capital structure (excluding goodwill), and include a formula for calculating the return on equity component of the cost of capital. The proposed legislation would apply to electric and gas utilities in Illinois on an opt-in basis and would not have any effect on the IPA process for energy procurement.

If the proposed legislation were to be enacted, ComEd would anticipate adopting a formula rate and investing an additional $2.6 billion in capital expenditures over the next ten years to modernize its system and implement smart grid technology, including improvements to cyber security. These investments would be incremental to ComEd's otherwise planned capital expenditures. However, there can be no assurances that the proposed legislation will be enacted into law.

2011 Pennsylvania Electric and Natural Gas Rates. On December 16, 2010, the PAPUC approved the settlement of PECO's electric distribution rate case for an increase of $225 million in annual service revenue, which is approximately 71% of the $316 million originally requested. The natural gas distribution rate case settlement reflects an increase of approximately $20 million in annual service revenue, which is approximately 46% of the $44 million originally requested. The approved electric and natural gas distribution rates became effective on January 1, 2011.

In accordance with the DSP Program, PECO has completed four competitive procurements for electric supply for default electric service customers commencing January 2011. As of December 31, 2010, PECO had procured substantially all of the total estimated electric supply needed to serve the residential customer class in 2011.

The approved electric distribution rate case settlement and the 2010 electric supply procurement results indicate an increase of 5.1% in the average residential customer total electric bill on January 1, 2011, above 2010 bills.

The approved natural gas distribution rate case settlement and the estimated 2011 PGC costs will result in an increase of 1% in the average residential customer total natural gas bill on January 1, 2011, above 2010 bills.

See Note 2 of the Combined Notes to Consolidated Financial Statements for further details related to PECO's rate case and procurement proceedings.

Financial Reform Legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act was enacted into law on July 21, 2010. This financial reform legislation includes a provision that requires over-the-counter derivative transactions to be executed through an exchange or centrally cleared. The legislation provides an exemption from mandatory clearing requirements for transactions that are used to hedge commercial risk like those utilized by Generation. At the same time, the legislation includes provisions under which the Commodity Futures Trading Commission may impose collateral requirements for transactions, including those that are used to hedge commercial risk. However, during drafting of the legislation, members of Congress issued a public letter stating that it was not their intention to impose margin and collateral requirements on counterparties that utilize transactions to hedge commercial risk. Final rules on major provisions in the legislation, including new margin requirements, will be established through rulemakings and will not take effect until 12 months after the date of enactment. If deemed a swap dealer, Generation would be required to execute over-the-counter derivative transactions, except those with qualifying end-users that are used to hedge commercial risk, through an exchange or central clearinghouse subject to margin requirements; conversely, if deemed a qualifying end-user, Generation could elect not to clear such transactions. Although we believe a swap dealer designation is unlikely, a substantial shift from over-the-counter sales to exchange cleared sales is estimated to require approximately $1 billion of additional collateral. Generation has adequate credit facilities and flexibility in its hedging program to accommodate these legislative or market changes. Generation continues to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on its results of operations, cash flows or financial position.

New Jersey Capacity Legislation. New Jersey Senate Bill 2381 was enacted into law on January 28, 2011. This legislation establishes a long-term capacity pilot program under which the New Jersey Board of Public Utilities will administer an RFP process to solicit offers for capacity agreements with mid-merit and/or baseload generation constructed after the effective date of the bill. The pilot program seeks capacity agreements for a term of up to 15 years for 2,000 MW. The selected generators are required to bid in and clear the PJM RPM auction, likely causing them to bid in at zero. Generators are paid based on the RFP contract price; therefore any difference between the RPM clearing price and the RFP contract price is either ultimately recovered from or refunded to New Jersey electric customers. This state required customer subsidy for generation capacity is expected to artificially suppress capacity prices within the Mid-Atlantic region, which could adversely affect Generation's results of operations and cash flows. Other states could seek to establish similar programs, which could substantially impair Exelon's market driven position.

PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. On February 1, 2011, PJM Power Providers Group, of which Generation is a member, filed a complaint asking FERC to revise PJM's MOPR to mitigate this exercise of buyer market power. Generation expects PJM to make a similar filing at FERC. In addition, on February 9, 2011, Generation and others filed a complaint in Federal district court requesting that the court declare the statute unconstitutional and that it enjoin implementation of the statute.

Illinois State Income Tax Legislation. The Taxpayer Accountability and Budget Stabilization Act, (Senate Bill 2505), enacted into law in Illinois on January 13, 2011, increases the corporate tax rate in Illinois from 7.3% to 9.5% for tax years 2011 – 2014, provides for a reduction in the rate from 9.5% to 7.75% for tax years 2015 – 2024 and further reduces the rate from 7.75% to 7.3% for tax years 2025 and thereafter.

The rate change from 7.3% to 9.5% will result in a one-time charge or credit to deferred taxes as the balances must be recalculated at the new corporate tax rates. The Registrants are unable to estimate the impact at this time. Additionally, the rate change will increase Exelon's future Illinois state income taxes, net of offsetting Federal benefit, by approximately $25 million in 2011, of which $10 million and $10 million relate to Generation and ComEd, respectively.

Plant Retirements

Oyster Creek. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. The current NRC license for Oyster Creek expires in 2029. In reliance upon Exelon's determination to cease generation operations at Oyster Creek no later than December 31, 2019, the NJDEP has determined that closed cycle cooling is not the best technology available for Oyster Creek given the length of time that would be required to retrofit from the existing once-through cooling system to a closed-cycle cooling system and the limited life span of Oyster Creek after installation of a closed-cycle cooling system. Based on its consideration of these and other factors, in its best professional judgment, NJDEP has determined that the existing measures at Oyster Creek represent the best technology available for the facility's cooling water intake through cessation of generation operations. As a result of the announcement to close Oyster Creek by 2019, Generation's operating expenses increased by $7 million (pre-tax) in 2010 and are estimated to increase approximately $25-$30 million (pre-tax) in each of the years 2011 through 2015. The impacts to Generation's operating expenses in years 2016 through 2019 will be dependent on future capital spending at Oyster Creek. Generation will also make employee retention payments of approximately $20 million in 2011 that are expected to increase operating expenses by approximately $4 million (pre-tax) in each of the years 2011 through 2015.

Eddystone and Cromby. In 2009, Exelon announced its intention to permanently retire three coal-fired generating units and one oil/gas-fired generating unit effective May 31, 2011 in response to the economic outlook related to the continued operation of these four units. The units to be retired are Cromby Generating Station (Cromby) Unit 1 and Unit 2 and Eddystone Generating Station (Eddystone) Unit 1 and Unit 2. PJM determined that transmission reliability upgrades will be necessary to alleviate reliability impacts and that those upgrades will be completed in a manner that will permit Generation's retirement of the units on the following schedule: Cromby Unit 1 and Eddystone Unit 1 on May 31, 2011; Cromby Unit 2 on December 31, 2011; and Eddystone Unit 2 on June 1, 2012. As a result, on December 14, 2010, Generation reached a proposed settlement with FERC Staff and other intervenors regarding the terms of the reliability-must-run rate schedule, subject to FERC approval, for Cromby Unit 2 and Eddystone Unit 2. Under the proposed settlement, monthly fixed-cost recovery during the reliability-must-run period for Cromby Unit 2 and Eddystone Unit 2 would be approximately $2 million and $6 million, respectively. In addition, Generation would be reimbursed for variable costs including fuel, emissions costs, chemicals, auxiliary power and for project investment costs during the reliability-must-run period.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements. Management discusses these policies, estimates and assumptions with its Accounting and Disclosure Governance Committee on a regular basis and provides periodic updates on management decisions to the Audit Committees of the Exelon, ComEd and PECO Boards of Directors. Management believes that the areas described below require significant judgment in the application of accounting policy or in making estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional discussion of the application of these accounting policies can be found in the Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations

Generation must make significant estimates and assumptions in accounting for its obligation to decommission its nuclear generating plants in accordance with the authoritative guidance for AROs.

The authoritative guidance requires that Generation estimate its obligation for the future decommissioning of its nuclear generating plants. To estimate that liability, Generation uses a probability-weighted, discounted cash flow model that considers multiple outcome scenarios based upon significant estimates and assumptions embedded in the following:

Decommissioning Cost Studies. Generation uses unit-by-unit decommissioning cost studies to provide a marketplace assessment of the costs and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within its industry and other estimates. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years.

Cost Escalation Studies. Generation uses cost escalation factors to escalate the decommissioning costs from the decommissioning cost studies discussed above through the assumed decommissioning period for each of the units. Cost escalation studies, updated on an annual basis, are used to determine escalation factors; and are based on inflation indices for labor, equipment and materials, energy, LLRW disposal and other costs.

Probabilistic Cash Flow Models. Generation's probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning costs, approaches and timing on a unit-by-unit basis. Probabilities assigned to cost levels include an assessment of the likelihood of costs 20% higher (high-cost scenario) or 15% lower (low-cost scenario) then the base cost scenario. Probabilities assigned alternative decommissioning approaches assess the likelihood of performing DECON (a method of decommissioning shortly after the cessation of operation in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed and safely buried in a LLRW landfill or decontaminated to a level that permits property to be released for unrestricted use), Delayed DECON (similar to the DECON scenario but with a delay to allow for spent fuel to be removed from the site prior to onset of decommissioning activities) or SAFSTOR (a method of decommissioning in which the nuclear facility is placed and maintained in such condition that the nuclear facility can be safely stored and subsequently decontaminated to levels that permit release for unrestricted use generally within 60 years after cessation of operations) procedures. Probabilities assigned to the timing scenarios incorporate the likelihood of continued operation through current license lives or through anticipated license renewals. Generation's probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal, which Generation currently assumes will begin in 2020, based on the DOE's most recent indication. For more information regarding the estimated date that DOE will begin accepting SNF, see Note 18 of the Combined Notes to Consolidated Financial Statements.

License Renewals. Generation assumes a successful 20-year renewal for each of its nuclear generating station licenses, except for Oyster Creek, in determining its nuclear decommissioning ARO. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information on Oyster Creek. Generation has successfully secured 20-year operating license renewal extensions for eight of its nuclear units, and none of Generation's applications for an operating license extension has been denied. Generation is in various stages of the process of pursuing similar extensions on its remaining eleven operating nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG). Generation's assumption regarding license extension for ARO determination purposes is based in part on the good current physical condition and high performance of these nuclear units; the favorable status of the ongoing license renewal proceedings with the NRC, and the successful renewals for eight units to date. Generation estimates that the failure to obtain license renewals at any of these nuclear units (assuming all other assumptions remain constant) would increase its ARO on average approximately $190 million per unit as of December 31, 2010.

The size of the increase to the ARO for a particular nuclear unit is dependent upon the current stage in its original license term and its specific decommissioning cost estimates. If Generation does not receive license renewal on a particular unit, the increase to the ARO may be mitigated by Generation's ability to delay ultimate decommissioning activities under a SAFSTOR method of decommissioning.

Discount Rates. The probability-weighted estimated future cash flows using these various scenarios are discounted using credit-adjusted, risk-free rates (CARFR) applicable to the various businesses in which each of the nuclear units originally operated. Changes in the CARFR could result in significant changes in the ARO. If Generation used a 2009 CARFR instead of the 2010 CARFR in performing its third quarter ARO update, it would have resulted in a $180 million decrease in the ARO. Additionally, if the CARFR used in performing the third quarter 2010 ARO update was increased or decreased by 25 basis points, the ARO would have decreased $60 million or increased $90 million, respectively.

Changes in the assumptions underlying the foregoing items could materially affect the decommissioning obligation. The following table illustrates the effects of changing certain ARO assumptions, discussed above, while holding all other assumptions constant (dollars in millions):

Change in ARO Assumption	Increase to ARO at December 31, 2010
Cost escalation studies	
Uniform increase in escalation rates of 25 basis points	$450
Probabilistic cash flow models	
Increase the likelihood of the high-cost scenario by 10 percentage points and decrease the likelihood of the low-cost scenario by 10 percentage points	$150
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	$210
Increase the likelihood of operating through current license lives by 10 percentage points and decrease the likelihood of operating through anticipated license renewals by 10 percentage points	$370

If the estimated date for DOE acceptance of SNF were to be extended to 2030, Generation's aggregate nuclear decommissioning obligation would be reduced by an immaterial amount.

Under the authoritative guidance, the nuclear decommissioning obligation is adjusted on a regular basis due to the passage of time and revisions to the key assumptions for the expected timing or estimated amounts of the future undiscounted cash flows required to decommission the nuclear plants. For more information regarding accounting for nuclear decommissioning obligations, see Notes 1 and 12 of the Combined Notes to Consolidated Financial Statements.

Goodwill

ComEd has goodwill relating to the acquisition of ComEd in 2000 as part of the PECO/Unicom Merger. Under the provisions of the authoritative guidance for goodwill, ComEd is required to perform an assessment for impairment of its goodwill at least annually or more frequently if an event occurs, such as a significant negative regulatory outcome, or circumstances change that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. Under the authoritative guidance, a reporting unit is an operating segment or operating component and is the level at which goodwill is tested for impairment. The impairment assessment is performed using a two-step, fair value based test. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Application of the goodwill impairment test requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, operating and capital expenditure requirements and the fair value of debt. In applying the second step (if needed), management would need to estimate the fair value of specific assets and liabilities of the reporting unit.

ComEd did not recognize an impairment in 2010; however, adverse regulatory actions that could reduce ComEd's allowed long-term rate of return on common equity or a fully successful IRS challenge to Exelon's and ComEd's like-kind exchange income tax position in combination with changes in significant assumptions described above could potentially result in a future impairment loss of ComEd's goodwill, which could be material. If any combination of changes to significant assumptions resulted in a 5% reduction in fair value as of November 1, 2010, ComEd still would have passed the first step of the goodwill assessment. See Notes 2 and 7 of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting

Determining the fair value of assets acquired and liabilities assumed in a business combination is judgmental in nature and often involves the use of significant estimates and assumptions. Some of the more significant estimates and assumptions used in valuing Generation's acquisition of John Deere Renewables on December 9, 2010 include: projected future cash flows (including timing); discount rates reflecting the risk inherent in the future cash flows; and future market prices. There are also judgments made to determine the expected useful lives assigned to each class of assets acquired and liabilities assumed. Generation did not record any goodwill related to the acquisition of John Deere Renewables.

Impairment of Long-lived Assets

Exelon, Generation, ComEd and PECO evaluate their long-lived assets, excluding goodwill, for impairment when circumstances indicate the carrying value of those assets may not be recoverable. Conditions that could have an adverse impact on the cash flows and fair value of the long-lived assets are deteriorating business climate, including current energy and market conditions, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life. The review of long-lived assets for impairment requires significant assumptions about operating strategies and estimates of future cash flows, which require assessments of current and projected market conditions. For the generation business, forecasting future cash flows requires assumptions regarding forecasted commodity prices for the sale of power, costs of fuel and the expected operations of assets. A variation in the assumptions used could lead to a different conclusion regarding the realizability of an asset and, thus, could have a significant effect on the consolidated financial statements. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level at which cash flows of the long-lived assets are largely independent of other groups of assets and liabilities. For the generation business, the lowest level of independent cash flows is determined by evaluation of several factors, including the geographic dispatch of the generation units and the hedging strategies related to those units. For ComEd and PECO, the lowest level of independent cash flows is determined by evaluation of several factors including the ratemaking jurisdiction in which they operate and the type of service or commodity provided. For ComEd, the lowest level of independent cash flows is transmission and distribution and for PECO, the lowest level of independent cash flows is transmission, distribution and gas. Impairment may occur when the carrying value of the asset or asset group exceeds the future undiscounted cash flows. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. Events and circumstances frequently do not occur as expected and there will usually be differences between prospective financial information and actual results, and those differences may be material. Additionally, some assumptions or projections inevitably will not materialize and unanticipated events and circumstances may occur during the forecast period. These could include, among others, major changes in the economic environment; significant increases or decreases in current mortgage interest rates and/or terms or availability of financing altogether; property assessment; and/or major revisions in current state and/or Federal tax or regulatory laws. Therefore, the actual results achieved during the projected holding period and investor requirements relative to anticipated annual returns and overall yields could vary from the projection. Accordingly, to the extent that any of the information used in the fair value analysis requires adjustment, the resulting fair market value would be different. As such, the determination of fair value is driven by both internal assumptions as well as information from various public, financial and industry sources. An impairment determination would require the affected Registrant to reduce both the long-lived asset and current period earnings by the amount of the impairment.

Exelon holds certain investments in coal-fired plants in Georgia and Texas subject to long-term leases. Exelon determines the investment in these plants by incorporating an estimate of the residual values of the leased assets. On an annual basis, Exelon reviews the estimated residual values of these plants to determine if the current estimate of their residual value is lower than the one used at the start of the lease. In determining the estimate of the residual value the expectation of future market conditions, including commodity prices, is considered. If the estimated residual value is lower than at the start of the lease and the decline is considered to be other than temporary, a loss will be recognized with a corresponding reduction to the carrying amount of the investment. To date, no such losses have been recognized.

See Note 5 of the Combined Notes to Consolidated Financial Statements for a discussion of asset impairment evaluations made by Generation.

Depreciable Lives of Property, Plant and Equipment

The Registrants have significant investments in electric generation assets and electric and natural gas transmission and distribution assets. Depreciation of these assets is generally provided over their estimated service lives on a straight-line basis using the composite method. The estimation of service lives requires management judgment regarding the period of time that the assets will be in use. As circumstances warrant, the estimated service lives are reviewed to determine if any changes are needed. Depreciation rates incorporate assumptions on interim retirements based on actual historical retirement experience. To the extent interim retirement patterns change, this could have a significant impact on the amount of depreciation expense recorded in the income statement. Changes to depreciation estimates resulting from a change in the estimated end of service lives could have a significant impact on the amount of depreciation expense recorded in the income statement. See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding depreciation and estimated service lives of the property, plant and equipment of the Registrants.

The estimated service lives of the nuclear generating facilities are based on the estimated useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek. See Note 18 of the Combined Notes to Consolidated Financial Statements for information regarding Oyster Creek. While Generation has received license renewals for certain facilities, and has applied for or expects to apply for and obtain approval of license renewals for the remaining facilities, circumstances may arise that would prevent Generation from obtaining additional license renewals. Generation also periodically evaluates the estimated service lives of its fossil fuel generating facilities based on feasibility assessments as well as economic and capital requirements. The estimated service lives of the hydroelectric generating facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the operating licenses. A change in depreciation estimates resulting from Generation's extension or reduction of the estimated service lives could have a significant effect on Generation's results of operations. Generation completed a depreciation rate study during the first quarter of 2010, which resulted in the implementation of new depreciation rates effective January 1, 2010.

ComEd is required to file a depreciation rate study at least every five years with the ICC. ComEd filed a depreciation rate study with the ICC in January 2009, which resulted in the implementation of new depreciation rates effective January 1, 2009.

PECO is required to file a depreciation rate study at least every five years with the PAPUC. In April 2010, PECO filed a depreciation rate study with the PAPUC for both its electric and gas assets, which resulted in the implementation of new depreciation rates effective January 2011.

Defined Benefit Pension and Other Postretirement Benefits

Exelon sponsors defined benefit pension plans and postretirement benefit plans for substantially all Generation, ComEd, PECO, and Exelon Corporate employees. See Note 13 of the Combined Notes to Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension plans and postretirement benefit plans.

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit and other postretirement plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Exelon's expected level of contributions to the plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, the long-term expected investment rate credited to employees of certain plans and the anticipated rate of increase of health care costs, among other factors. The assumptions are updated annually and upon any interim remeasurement of the plan obligations. The impact of assumption changes on pension and other postretirement benefit obligations is generally recognized over the expected average remaining service period of the employees rather than immediately recognized in the income statement. Pension and postretirement benefit costs attributed to the operating companies are labor costs and are ultimately allocated to projects within the operating companies, some of which are capitalized.

Pension and postretirement benefit plan assets include equity securities, including U.S. and international securities, and fixed income securities, as well as certain alternative investment classes such as real estate, private equity and hedge funds. See Note 13 of the Combined Notes to Consolidated Financial Statements for information on fair value measurements of pension and other postretirement plan assets, including valuation techniques and classification in accordance with authoritative guidance under the fair value hierarchy.

Expected Rate of Return on Plan Assets. The long-term expected rate of return on plan assets assumption used in calculating pension costs was 8.50%, 8.50% and 8.75% for 2010, 2009 and 2008, respectively. The weighted average EROA assumption used in calculating other postretirement benefit costs was 7.83%, 8.10% and 7.80% in 2010, 2009 and 2008, respectively. The pension trust activity is non-taxable, while other postretirement benefit trust activity is partially taxable. The EROA is based on asset allocations at year end. In 2010, Exelon modified its pension investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. As a result of this modification, over time, Exelon plans to decrease equity investments and increase investments in fixed income securities and alternative investments in order to achieve a balanced portfolio of risk-reducing and return-seeking assets. The change in the overall investment strategy will likely lower the expected rate of return on plan assets in future years as compared to the previous strategy. See Note 13 of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's asset allocations. Exelon used an EROA of 8.00% and 7.08% to estimate its 2011 pension and other postretirement benefit costs, respectively. For 2012, Exelon projects an EROA of 7.50% and 7.08% for pension and other postretirement benefit costs, respectively.

Exelon calculates the expected return on pension and other postretirement benefit plan assets by multiplying the EROA by the MRV of plan assets at the beginning of the year, taking into consideration anticipated contributions and benefit payments to be made during the year. In determining MRV, the authoritative guidance for pensions and postretirement benefits allows the use of either fair value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years. For the majority of pension plan assets, Exelon uses a calculated value that adjusts for 20% of the difference between fair value and expected MRV of plan assets. Use of this calculated value approach enables less volatile expected asset returns to be recognized as a component of pension cost from year to year. For other postretirement benefit plan assets and certain pension plan assets, Exelon uses fair value to calculate the MRV.

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and other postretirement benefit plans. The actual asset returns across the Registrant's pension and other postretirement benefit plans for the year ended December 31, 2010 were 11.9% and 11.6%, respectively, compared to an expected long-term return assumption of 8.50% and 7.83%, respectively. Those return levels are expected to decrease 2011 and 2012 benefit costs as follows:

(dollars in millions)	**Decrease in 2011 Pension Cost**	**Decrease in 2011 Postretirement Benefit Cost**	**Decrease in 2012 Pension Cost**	**Decrease in 2012 Postretirement Benefit Cost**
2010 actual asset returns	$(8)	$(8)	$(15)	$(7)

This information assumes that movements in asset returns occur absent changes to other actuarial assumptions, and does not consider any actions management may take, such as changes to the amount and timing of future contributions. The actuarial assumptions used in the determination of pension and postretirement benefit costs are interrelated and changes in other assumptions could have the impact of offsetting all or a portion of the potential decrease in benefit costs set forth above.

Discount Rate. The discount rates used to determine the pension and other postretirement benefit obligations at December 31, 2010 were 5.26% and 5.30%, respectively, and the discount rates for determining both the pension and other postretirement benefit obligations at December 31, 2009 and 2008 were 5.83% and 6.09%, respectively. At December 31, 2010, 2009 and 2008, the discount rate was determined by developing a spot rate curve based on the yield to maturity of a universe of high-quality non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and other postretirement benefit obligations. The spot rates are used to discount the estimated distributions under the pension and other postretirement benefit plans. The discount rate is the single level rate that produces the same result as the spot rate curve. Exelon utilizes an analytical tool developed by its actuaries to determine the discount rates.

The discount rate assumptions used to determine the obligation at year end are used to determine the cost for the following year. Exelon will use discount rates of 5.26% and 5.30% to estimate its 2011 pension and other postretirement benefit costs, respectively.

Health Care Reform Legislation. In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers. In particular, the Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Although the excise tax does not go into effect until 2018, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Certain key assumptions are required to estimate the impact of the excise tax on Exelon's other postretirement obligation, including projected inflation rates (based on the CPI) and whether pre- and post-65 retiree populations can be aggregated in determining the premium values of health care benefits. Exelon reflected its best estimate of the expected impact in its annual actuarial valuation, which increased its postretirement benefit obligation by $145 million as of December 31, 2010 and increases annual other postretirement benefit costs by approximately $32 million, beginning in 2011.

The excise tax is applied to the value of retiree health care benefits in excess of certain thresholds, which increase each year based on the rate of CPI. Therefore, the assumed rate of CPI impacts the extent to which Exelon's future retiree health care benefit premiums exceed the thresholds. Exelon assumed an annual CPI of 2.5% in calculating the impact of the excise tax on Exelon's other postretirement obligation as of December 31, 2010. As of December 31, 2010, a 50 basis point decrease in the assumed CPI (holding all other assumptions constant) would have increased Exelon's other postretirement benefit obligation by approximately $70 million, and a 50 basis point increase in the assumed CPI would have decreased Exelon's other postretirement benefit obligation by approximately $65 million.

The impact of the excise tax is also dependent on whether pre- and post-65 retirees can be aggregated for purposes of calculating the value of health care benefits provided by Exelon. The value of the health care benefits provided to pre-65 employees is greater than the value for post-65 employees because pre-65 employees are not eligible for Medicare. The aggregation of pre- and post-65 retiree populations reduces the average value of the health care benefits and, therefore, results in less excise tax. Exelon has assumed pre- and post-65 retirees will be allowed to be aggregated for purposes of calculating the impact of the excise tax on its other postretirement benefit obligation as of December 31, 2010. The disaggregation of pre- and post-65 retiree populations would have increased Exelon's other postretirement benefit obligation by approximately $200 million (holding all other assumptions constant) as of December 31, 2010.

Health Care Cost Trend Rate. Assumed health care cost trend rates have a significant effect on the costs reported for Exelon's other postretirement benefit plans. Accounting guidance requires that annual health care cost estimates be developed using past and present health care cost trends (both for Exelon and across the broader economy), as well as expectations of health care cost escalation, changes in health care utilization and delivery patterns, technological advances and changes in the health status of plan participants. Therefore, the trend rate assumption is subject to significant uncertainty, particularly when considering potential impacts of the 2010 Health Care Reform Acts. Exelon assumed a health care cost trend rate of 7.00% at December 31, 2010, decreasing to an ultimate health care cost trend rate of 5.00% in 2015.

Sensitivity to Changes in Key Assumptions: The following tables illustrate the effects of changing certain of the actuarial assumptions discussed above, while holding all other assumptions constant (dollars in millions):

Actuarial Assumption	Change in Assumption	Pension	Other Postretirement Benefits	Total
Change in 2010 cost:				
Discount rate [(a)]	0.5%	$ (51)	$ (27)	$ (78)
	(0.5)%	55	27	82
EROA	0.5%	(47)	(7)	(54)
	(0.5)%	47	7	54
Health care trend rate	1.00%	N/A	53	53
	(1.00)%	N/A	(43)	(43)
	Extend the year at which the ultimate health care trend rate of 5% is forecasted to be reached by 5 years	N/A	20	20
Change in benefit obligation at December 31, 2010:				
Discount rate [(a)]	0.5%	(730)	(229)	(959)
	(0.5)%	775	243	1,018
Health care trend rate	1.00%	N/A	490	490
	(1.00)%	N/A	(405)	(405)
	Extend the year at which the ultimate health care trend rate of 5% is forecasted to be reached by 5 years	N/A	201	201

(a) In general, the discount rate will have a larger impact on the pension and other postretirement benefit cost and obligation as the rate moves closer to 0%. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated for larger increases or decreases in the discount rate.

Average Remaining Service Period. For pension benefits, Exelon amortizes its unrecognized prior service costs and certain actuarial gains and losses, as applicable, based on participants' average remaining service periods. The average remaining service period of defined benefit pension plan participants was 12.4 years, 12.7 years and 12.8 years for the years ended December 31, 2010, 2009 and 2008, respectively.

For other postretirement benefits, Exelon amortizes its unrecognized estimated prior service costs over participants' average remaining service period to benefit eligibility age and amortizes its transition obligations and certain actuarial gains and losses over participants' average remaining service period to expected retirement. The average remaining service period of postretirement benefit plan participants related to benefit eligibility age was 6.8 years, 6.8 years and 6.9 years for the years ended December 31, 2010, 2009 and 2008, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 9.0 years, 9.2 years and 9.4 years for the years ended December 31, 2010, 2009 and 2008, respectively.

Regulatory Accounting

Exelon, ComEd and PECO account for their regulated electric and gas operations in accordance with the authoritative guidance for accounting for certain types of regulations, which requires Exelon, ComEd, and PECO to reflect the effects of cost-based rate regulation in their financial statements. Use of this guidance is applicable to utility operations that meet the following criteria: (1) third-party regulation of rates; (2) cost-based rates; and (3) a reasonable expectation that all costs will be recoverable from customers through rates. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent (1) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (2) billings in advance of expenditures for approved regulatory programs. As of December 31, 2010, Exelon, ComEd and PECO have concluded that the operations of ComEd and PECO meet the criteria of the authoritative guidance. If it is concluded in a future period that a separable portion of those operations no longer meets the criteria of this guidance, Exelon, ComEd and PECO would be required to eliminate any associated regulatory assets and liabilities and the impact would be recognized in the Consolidated Statements of Operations and Comprehensive Income and could be material. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon, ComEd and PECO.

For each regulatory jurisdiction in which they conduct business, Exelon, ComEd and PECO assess whether the regulatory assets and liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of factors such as changes in applicable regulatory and political environments, historical regulatory treatment for similar costs in ComEd and PECO's jurisdictions, and recent rate orders. Furthermore, Exelon, ComEd and PECO make other judgments related to the financial statement impact of their regulatory environments, such as the types of adjustments to rate base that will be acceptable to regulatory bodies and the types of costs and the extent, if any, to which those costs will be recoverable through rates. Additionally, estimates are made in accordance with the authoritative guidance for contingencies, as to the amount of revenues billed under certain regulatory orders that may ultimately be refunded to customers upon finalization of applicable regulatory or judicial processes. These assessments are based, to the extent possible, on past relevant experience with regulatory bodies in ComEd and PECO's jurisdictions, known circumstances specific to a particular matter and hearings held with the applicable regulatory body. If the assessments and estimates made by Exelon, ComEd and PECO are ultimately different than actual regulatory outcomes, the impact on their results of operations, financial position, and cash flows could be material.

Accounting for Derivative Instruments

The Registrants utilize derivative instruments to manage their exposure to fluctuations in interest rates, changes in interest rates related to planned future debt issuances and changes in the fair value of outstanding debt. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases and other energy-related products marketed and purchased. Additionally, Generation enters into energy-related derivatives for proprietary trading purposes. ComEd has entered into contracts to procure energy, capacity and ancillary services. In addition, ComEd has a financial swap contract with Generation that extends into 2013 and floating-to-fixed energy swaps with several unaffiliated suppliers that extend into 2032. PECO has entered into derivative natural gas contracts to hedge its long-term price risk in the natural gas market. As part of the preparation for the expiration of the PPA with Generation at the end of 2010, PECO has entered into derivative contracts to procure electric supply through a competitive RFP process as outlined in its PAPUC-approved DSP Program. ComEd and PECO do not enter into derivatives for proprietary trading purposes. The Registrants' derivative activities are in accordance with Exelon's Risk Management Policy (RMP). See Note 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

The Registrants account for derivative financial instruments under the applicable authoritative guidance. Determining whether or not a contract qualifies as a derivative under this guidance requires that management exercise significant judgment, including assessing the market liquidity as well as determining whether a contract has one or more underlyings and one or more notional amounts. Further, interpretive guidance related to the authoritative literature continues to evolve, including how it applies to energy and energy-related products. Changes in management's assessment of contracts and the liquidity of their markets, and changes in authoritative guidance related to derivatives, could result in previously excluded contracts being subject to the provisions of the authoritative derivative guidance. Generation has determined that contracts to purchase uranium and contracts to purchase and sell RECs do not meet the definition of a derivative under the current authoritative guidance since they do not provide for net settlement and neither the uranium or REC markets are sufficiently liquid to conclude that forward contracts are readily convertible to cash. If the uranium or REC markets do become sufficiently liquid in the future and Generation begins to account for uranium purchase contracts or REC purchase and sale contracts as derivative instruments, the fair value of these contracts would be accounted for consistent with Generation's other derivative instruments. In this case, if market prices differ from the underlying prices of the contracts, Generation would be required to record a mark-to-market gain or loss, which may have a material impact to Exelon's and Generation's financial positions and results of operations.

Under current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value unless they qualify for a normal purchases and normal sales exception. Further, derivatives that qualify and are designated for hedge accounting are classified as fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting and for energy-related derivatives entered for proprietary trading purposes, changes in the fair value of the derivatives are recognized in earnings each period except for ComEd and PECO, in which changes in the fair value each period are recorded as a regulatory asset or liability.

Normal Purchases and Normal Sales Exception. Determining whether a contract qualifies for the normal purchases and normal sales exception requires that management exercise judgment on whether the contract will physically deliver and requires that management ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts which qualify for the normal purchases and normal sales exception are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and price is not tied to an unrelated underlying derivative. As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. While these contracts are considered derivative financial instruments under the authoritative guidance, the transactions have been designated as normal purchases and normal sales and are thus not required to be recorded at fair value, but rather on an accrual basis of accounting. The contracts that ComEd has entered into with Generation and other suppliers as part of the initial ComEd procurement auction and the subsequent RFP process, PECO's full requirement contracts and block contracts under the PAPUC-approved DSP program and all of PECO's natural gas supply agreements that are derivatives qualify for the normal purchases and normal sales exception. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the scope exceptions, the fair value of the related contract would be recorded on the balance sheet and immediately recognized through earnings at Generation or offset by a regulatory asset or liability at ComEd and PECO. Thereafter, future changes in fair value would be recorded in the balance sheet and recognized through earnings at Generation. Triggering events that could result in a contract's loss of the normal purchase and normal sale designation, because it is no longer probable that the contract will result in physical delivery, include changes in business requirements, changes in counterparty credit and financial rather than physical contract settlements (book-outs).

Commodity Contracts. Identification of a commodity contract as a qualifying cash flow hedge requires Generation to determine that the contract is in accordance with the RMP, the forecasted future transaction is probable and the hedging relationship between the commodity contract and the expected future purchase or sale of the commodity is expected to be highly effective at the initiation of the hedge and throughout the hedging relationship. Internal models that measure the statistical correlation between the derivative and the associated hedged item determine the effectiveness of such a commodity contract designated as a hedge. Generation reassesses its cash flow hedges on a regular basis to determine if they continue to be effective and whether the forecasted future transactions remain probable. When a contract does not meet the effective or probable criteria of the authoritative guidance, hedge accounting is discontinued and changes in the fair value of the derivative are recorded through earnings at Generation or offset by a regulatory asset or liability at ComEd and PECO.

As a part of accounting for derivatives, the Registrants make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions. In accordance with the authoritative guidance for fair value measurements, the Registrants categorize these derivatives under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain non-exchange-based derivatives valued using indicative price quotations available through brokers or over-the-counter, on-line exchanges are categorized in Level 2. These price quotations reflect the average of the bid-ask mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The Registrant's non-exchange-based derivatives are traded predominately at liquid trading points. The remainder of non-exchange-based derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, and assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For non-exchange-based derivatives that trade in liquid markets, such as generic forwards, swaps and options, Black model inputs are generally observable. Such instruments are categorized in Level 2. For non-exchange-based derivatives that trade in less liquid markets with limited pricing information, such as the financial swap contract between Generation and ComEd, Black model inputs generally would include both observable and unobservable inputs. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the Black model inputs generally are not observable. The Registrants consider nonperformance risk, including credit risk in the valuation of derivative contracts categorized in Level 1, 2 and 3, including both historical and current market data in its assessment of nonperformance risk, including credit risk. The impacts of credit and nonperformance risk to date have generally not been material to the financial statements.

Interest Rate Derivative Instruments. The Registrants may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. Additionally, the Registrants may use forward-starting interest rate swaps and treasury rate locks to lock in interest-rate levels in anticipation of future financings. The Registrants use a calculation of future cash inflows and estimated future outflows related to the swap agreements, which are discounted and netted to determine the current fair value. Additional inputs to the present value calculation include the contract terms, as well as market parameters such as interest rates and volatility. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy.

See Quantitative and Qualitative Disclosures About Market Risk and Notes 8 and 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

Taxation

Significant management judgment is required in determining the Registrants' provisions for income taxes, primarily due to the uncertainty related to tax positions taken, as well as deferred tax assets and liabilities and valuation allowances. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition criterion and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being ultimately realized upon ultimate settlement. If it is not more likely than not that the benefit of the tax position will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of unrecognized tax benefits to be recorded in the Registrants' consolidated financial statements.

The Registrants evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. The Registrants also assess their ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. The Registrants record valuation allowances for deferred tax assets when the Registrants conclude it is more likely than not such benefit will not be realized in future periods.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, the Registrants' forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. While the Registrants believe the resulting tax balances as of December 31, 2010 and 2009 are appropriately accounted for in accordance with the applicable authoritative guidance, the ultimate outcome of tax matters could result in favorable or unfavorable adjustments to their consolidated financial statements and such adjustments could be material. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

Accounting for Contingencies

In the preparation of their financial statements, the Registrants make judgments regarding the future outcome of contingent events and record loss contingency amounts that are probable and reasonably estimable based upon available information. The amounts recorded may differ from the actual income or expense incurred when the uncertainty is resolved. The estimates that the Registrants make in accounting for contingencies and the gains and losses that they record upon the ultimate resolution of these uncertainties could have a significant effect on their consolidated financial statements.

Environmental Costs. Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work, changes in technology, regulations and the requirements of local governmental authorities. Annual studies are conducted to determine the future remediation requirements and estimates are adjusted accordingly. These matters, if resolved in a manner different from the estimate, could have a material effect on the Registrants' results of operations, financial position and cash flows. See Note 18 of the Combined Notes to Consolidated Financial Statements for further information.

Other, Including Personal Injury Claims. The Registrants are self-insured for general liability, automotive liability, and personal injury claims to the extent that losses are within policy deductibles or exceed the amount of insurance maintained. The Registrants have reserves for both open claims asserted and an estimate of claims incurred but not reported (IBNR). The IBNR reserve is estimated based on actuarial assumptions and analysis and is updated annually. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding litigation and possible legislative measures in the United States, could cause the actual costs to be higher or lower than estimated. Accordingly, these claims, if resolved in a manner different from the estimate, could have a material effect on the Registrants' results of operations, financial position and cash flows.

Revenue Recognition

Revenues related to the sale of energy are recorded when service is rendered or energy is delivered to customers. The determination of Generation's, ComEd's and PECO's retail energy sales to individual customers, however, is based on systematic readings of customer meters generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is affected by the following factors: daily customer usage measured by generation or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases in volumes delivered to the utilities' customers and favorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date would also have an effect on the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged.

The determination of Generation's energy sales, excluding the retail business, is based on estimated amounts delivered as well as fixed quantity sales. At the end of each month, amounts of energy delivered to customers during the month are estimated and the corresponding unbilled revenue is recorded. Increases in volumes delivered to the wholesale customers in the period, as well as price, would increase unbilled revenue.

Allowance for Uncollectible Accounts

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable agings, historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balance by risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. ComEd and PECO customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd and PECO customer accounts are written off consistent with approved regulatory requirements. ComEd's and PECO's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC and PAPUC regulations, respectively. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information regarding accounts receivable.

Results of Operations by Business Segment

The comparisons of operating results and other statistical information for the years ended December 31, 2010, 2009 and 2008 set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Net Income (Loss) from Continuing Operations by Business Segment

	2010	2009	Favorable (unfavorable) 2010 vs. 2009 variance	2008	Favorable (unfavorable) 2009 vs. 2008 variance
Generation	$1,972	$2,122	$(150)	$2,258	$(136)
ComEd	337	374	(37)	201	173
PECO	324	353	(29)	325	28
Other [(a)]	(70)	(142)	72	(67)	(75)
Total	$2,563	$2,707	$(144)	$2,717	$ (10)

(a) Other primarily includes corporate operations, BSC and intersegment eliminations.

Net Income (Loss) by Business Segment

	2010	2009	Favorable (unfavorable) 2010 vs. 2009 variance	2008	Favorable (unfavorable) 2009 vs. 2008 variance
Generation	$1,972	$2,122	$(150)	$2,278	$(156)
ComEd	337	374	(37)	201	173
PECO	324	353	(29)	325	28
Other [(a)]	(70)	(142)	72	(67)	(75)
Total	$2,563	$2,707	$(144)	$2,737	$ (30)

(a) Other primarily includes corporate operations, BSC and intersegment eliminations.

Results of Operations—Generation

	2010	2009	Favorable (unfavorable) 2010 vs. 2009 variance	2008	Favorable (unfavorable) 2009 vs. 2008 variance
Operating revenues	$10,025	$9,703	$ 322	$10,754	$(1,051)
Purchased power and fuel expense	3,463	2,932	(531)	3,572	640
Revenue net of purchased power and fuel expense [(a)]	6,562	6,771	(209)	7,182	(411)
Other operating expenses					
Operating and maintenance	2,812	2,938	126	2,717	(221)
Depreciation and amortization	474	333	(141)	274	(59)
Taxes other than income	230	205	(25)	197	(8)
Total other operating expenses	3,516	3,476	(40)	3,188	(288)
Operating income	3,046	3,295	(249)	3,994	(699)
Other income and deductions					
Interest expense	(153)	(113)	(40)	(136)	23
Loss in equity method investments	—	(3)	3	(1)	(2)
Other, net	257	376	(119)	(469)	845
Total other income and deductions	104	260	(156)	(606)	866
Income from continuing operations before income taxes	3,150	3,555	(405)	3,388	167
Income taxes	1,178	1,433	255	1,130	(303)
Income from continuing operations	1,972	2,122	(150)	2,258	(136)
Income from discontinued operations, net of income taxes	—	—	—	20	(20)
Net income	$ 1,972	$2,122	$(150)	$ 2,278	$ (156)

(a) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this Financial Information supplement.

Net Income

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. Generation's 2010 results compared to 2009 were lower due to decreased revenue net of purchased power and fuel expense due to lower margins realized on market and affiliate power sales primarily due to unfavorable market conditions, lower mark-to-market gains on economic hedging activities and increased nuclear fuel costs; partially offset by higher capacity revenues, including RPM, and favorable settlements on the ComEd swap.

Generation's 2010 results compared to 2009 were further affected by lower operating and maintenance expenses. Lower operating and maintenance expenses were primarily due to the impact of a $223 million charge associated with the impairment of the Handley and Mountain Creek stations recorded in 2009. Lower operating and maintenance expenses were partially offset by higher expense due to the absence of ARO reductions that occurred in 2009; higher wages and benefits costs; and higher nuclear refueling outage costs in 2010. Additionally, Generation's earnings decreased due to lower unrealized gains in its NDTs of the Non-Regulatory Agreement Units in 2010 compared to 2009.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. Generation's 2009 results compared to 2008 were lower due to decreased revenue net of purchased power and fuel expense due to lower realized margins on affiliate and market sales due to unfavorable market conditions, lower mark-to-market gains, reduced revenue from certain long options in Generation's proprietary trading book and increased nuclear fuel costs. These decreases were partially offset by additional volumes available for market and retail sales, favorable settlements under the ComEd swap and reduced customer credits issued to ComEd and Ameren.

Generation's 2009 results compared to 2008 were further affected by higher operating and maintenance expenses. Higher operating and maintenance expenses were primarily due to a $223 million charge associated with the impairment of the Handley and Mountain

Creek stations and costs associated with the announced shut-down of three coal-fired and one dual fossil-fired generation unit in Pennsylvania. These actions were a direct result of current and future expected market conditions. Market conditions also contributed to lower than expected pension and postretirement plan asset returns in 2008, which resulted in higher pension and other postretirement benefits expense in 2009. Higher operating and maintenance expenses were partially offset by the favorable results of Exelon's company-wide cost savings initiative and lower nuclear refueling outage costs.

Additionally, due to a significant rebound in the financial markets, Generation experienced strong performance in its NDT funds in 2009. As a result, Generation's earnings improved as its NDTs of the Non-Regulatory Agreement Units had significant net realized and unrealized gains in 2009 compared to significant net realized and unrealized losses in 2008.

Revenue Net of Purchased Power and Fuel Expense

Generation has three reportable segments, the Mid-Atlantic, Midwest, and South and West regions representing the different geographical areas in which Generation's power marketing activities are conducted. Mid-Atlantic includes Generation's operations primarily in Pennsylvania, New Jersey and Maryland; Midwest includes the operations in Illinois, Indiana, Michigan and Minnesota; and the South and West includes operations primarily in Texas, Georgia, Oklahoma, Kansas, Missouri, Idaho and Oregon.

Generation evaluates the operating performance of its power marketing activities using the measure of revenue net of purchased power and fuel expense. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd and PECO. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for internally-generated energy and fuel costs associated with tolling agreements. Generation's retail gas, proprietary trading, other revenue and mark-to-market activities are not allocated to a region.

For the year ended December 31, 2010 compared to 2009 and 2009 compared to 2008, Generation's revenue net of purchased power and fuel expense by region were as follows:

			2010 vs. 2009			2009 vs. 2008	
	2010	2009	Variance	% Change	2008	Variance	% Change
Mid-Atlantic [a][b]	$2,512	$2,578	$ (66)	(2.6)%	$2,721	$(143)	(5.3)%
Midwest [b]	4,081	4,148	(67)	(1.6)%	4,100	48	1.2%
South and West	(131)	(117)	(14)	(12.0)%	(73)	(44)	(60.3)%
Total electric revenue net of purchased power and fuel expense	$6,462	$6,609	$(147)	(2.2)%	$6,748	$(139)	(2.1)%
Trading portfolio	27	1	26	n.m.	106	(105)	(99.1)%
Mark-to-market gains	86	181	(95)	(52.5)%	452	(271)	(60.0)%
Other [c][d]	(13)	(20)	7	35.0%	(124)	104	83.9%
Total revenue net of purchased power and fuel expense	$6,562	$6,771	$(209)	(3.1)%	$7,182	$(411)	(5.7)%

(a) Included in the Mid-Atlantic are the results of generation in New England.
(b) Results of transactions with PECO and ComEd are included in the Mid-Atlantic and Midwest regions, respectively.
(c) Includes retail gas activities and other operating revenues, which includes amounts paid related to the Illinois Settlement Legislation, decommissioning revenues from PECO and fuel sales.
(d) In 2010, Other also includes the $57 million impairment charge for the ARP SO_2 allowances further described in Note 18 of the Combined Notes to Consolidated Financial Statements.

Generation's supply sources by region are summarized below:

Supply source (GWh)	2010	2009	2010 vs. 2009 Variance	2010 vs. 2009 % Change	2008	2009 vs. 2008 Variance	2009 vs. 2008 % Change
Nuclear generation							
Mid-Atlantic [a]	47,517	47,866	(349)	(0.7)%	47,748	118	0.2%
Midwest	92,493	91,804	689	0.8%	91,594	210	0.2%
Fossil and renewables							
Mid-Atlantic [b]	9,436	8,938	498	5.6%	9,804	(866)	(8.8)%
Midwest	68	4	64	n.m.	9	(5)	(55.6)%
South and West	1,213	1,247	(34)	(2.7)%	756	491	64.9%
Purchased power [c]							
Mid-Atlantic	1,918	1,747	171	9.8%	2,314	(567)	(24.5)%
Midwest	7,032	7,738	(706)	(9.1)%	8,628	(890)	(10.3)%
South and West	12,112	13,721	(1,609)	(11.7)%	15,321	(1,600)	(10.4)%
Total supply by region							
Mid-Atlantic	58,871	58,551	320	0.5%	59,866	(1,315)	(2.2)%
Midwest	99,593	99,546	47	0.0%	100,231	(685)	(0.7)%
South and West	13,325	14,968	(1,643)	(11.0)%	16,077	(1,109)	(6.9)%
Total supply	171,789	173,065	(1,276)	(0.7)%	176,174	(3,109)	(1.8)%

(a) Includes Generation's proportionate share of the output of its nuclear generating plants, including Salem Generating Station (Salem), which is operated by PSEG Nuclear, LLC
(b) Includes generation in New England.
(c) Includes non-PPA purchases of 4,681 GWh, 3,535 GWh and 7,384 GWh for the years ended December 31, 2010, 2009 and 2008, respectively.

Generation's sales are summarized below:

Sales (GWh) [a]	2010	2009	2010 vs. 2009 Variance	2010 vs. 2009 % Change	2008	2009 vs. 2008 Variance	2009 vs. 2008 % Change
ComEd [b]	5,323	16,830	(11,507)	(68.4)%	23,200	(6,370)	(27.5)%
PECO	42,003	39,897	2,106	5.3%	40,966	(1,069)	(2.6)%
Market and retail [c]	124,463	116,338	8,125	7.0%	112,008	4,330	3.9%
Total electric sales	171,789	173,065	(1,276)	(0.7)%	176,174	(3,109)	(1.8)%

(a) Excludes physical trading volumes of 3,625 GWh, 7,578 GWh and 8,891 GWh for the years ended December 31, 2010, 2009 and 2008, respectively.
(b) Represents sales under the 2006 ComEd auction.
(c) Includes sales under the ComEd RFP.

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the year ended December 31, 2010 as compared to the same period in 2009 and 2009 as compared to the same period in 2008.

$/MWh	2010	2009	2010 vs. 2009 % Change	2008	2009 vs. 2008 % Change
Mid-Atlantic [a]	$42.67	$44.03	(3.1)%	$45.45	(3.1)%
Midwest [a][b]	$40.98	$41.67	(1.7)%	$40.91	1.9%
South and West	$ (9.83)	$ (7.82)	(25.7)%	$ (4.54)	(72.2)%
Electric revenue net of purchased power and fuel expense per MWh [c]	$37.62	$38.20	(1.5)%	$38.48	(0.7)%

(a) Results of transactions with PECO and ComEd are included in the Mid-Atlantic and Midwest regions, respectively.
(b) Includes sales to ComEd under its RFP of $288 million (8,218 GWh), $88 million (1,916 GWh) and $29 million (486 GWh) and settlements of the ComEd swap of $385 million, $292 million and $(2) million for the years ended December 31, 2010, 2009 and 2008, respectively.
(c) Excludes the mark-to-market impact of Generation's economic hedging activities, trading portfolio and other.

Mid-Atlantic

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The $66 million decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic was primarily due to unfavorable pricing relating to Generation's PPA with PECO and increased fuel expense. Additionally, increased sales to PECO resulted in less volumes available for market sales.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. The $143 million decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic was primarily due to reduced volumes of sales and unfavorable pricing relating to Generation's PPA with PECO, lower realized margins on market sales as well as increased costs of nuclear and fossil fuels.

Midwest

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The $67 million decrease in revenue net of purchased power and fuel expense in the Midwest was primarily due to decreased realized margins on market sales in 2010 for the volumes previously sold under the 2006 ComEd auction contracts and for sales of the additional nuclear volumes at realized lower prices as a result of unfavorable market conditions and increases in the price of nuclear fuel. These decreases were partially offset by increased payments under PJM's RPM auction and an increase in settlements on the ComEd swap as a result of declining market prices in 2010.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. The $48 million increase in revenue net of purchased power and fuel expense in the Midwest was primarily due to increased market and retail sales, including additional volumes sold under the ComEd RFP and increased settlements under the ComEd swap. These increases were partially offset by lower volumes sold under the ComEd auction contract due to the expiration of certain tranches and increased nuclear fuel costs.

South and West

In the South and West, there are certain long-term purchase power agreements that have fixed capacity payments based on unit availability. The extent to which these fixed payments are recovered is dependent on market conditions.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The $14 million decrease in revenue net of purchased power and fuel expense in the South and West was primarily due to lower realized margins due to unfavorable market conditions and outage activity, partially offset by capacity revenues received on long-term sale agreements that began in 2010.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. The $44 million decrease in revenue net of purchased power and fuel expense in the South and West was primarily due to lower realized margins due to unfavorable market conditions and higher fuel costs associated with owned generation.

Trading Portfolio

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The year ended December 31, 2010 includes revenue recorded from certain long options in the proprietary trading portfolio.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. The trading portfolio revenues decreased due primarily to earnings in 2008 from certain long options in the proprietary trading portfolio.

Mark-to-market Gains and Losses

Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. Mark-to-market losses on power hedging activities were $3 million in 2010, including the impact of the changes in ineffectiveness, compared to gains of $94 million in 2009. Mark-to-market gains on fuel hedging activities were $89 million in 2010 compared to gains of $87 million in 2009. See Notes 8 and 9 of the Combined Notes to Consolidated Financial Statements for information on gains associated with mark-to-market derivatives.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. Mark-to-market gains on power hedging activities were $94 million in 2009, including the impact of the changes in ineffectiveness, compared to gains of $414 million in 2008. Mark-to-market gains on fuel hedging activities were $87 million in 2009 compared to gains of $38 million in 2008. See Notes 8 and 9 of the Combined Notes to Consolidated Financial Statements for information on gains associated with mark-to-market derivatives.

Other

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The increase in other is due to the impacts of $77 million in reduced customer credits issued to ComEd and Ameren associated with the Illinois Settlement Legislation further described in Note 2 of the Combined Notes to Consolidated Financial Statements. This increase in other revenue net of purchased power and fuel expense was partially offset by the $57 million impairment charge for the ARP SO_2 allowances further described in Note 18 of the Combined Notes to Consolidated Financial Statements and $13 million in lower fuel sales.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. The increase in other revenue net of purchased power and fuel expense was primarily due to the impacts of $123 million in reduced customer credits issued to ComEd and Ameren associated with the Illinois Settlement Legislation further described in Note 2 of the Combined Notes to Consolidated Financial Statements, partially offset by $24 million in lower fuel sales.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for 2010, as compared to 2009 and 2008, for the Exelon-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Nuclear fleet production cost is defined as the costs to produce one MWh of energy, including fuel, materials, labor, contracting and other miscellaneous costs, but excludes depreciation and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this Financial Information Supplement.

	2010	2009	2008
Nuclear fleet capacity factor [a]	93.9%	93.6%	93.9%
Nuclear fleet production cost per MWh [a]	$17.31	$16.07	$15.87[b]

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC.
(b) Excludes the $53 million reduction in fuel expense related to uranium supply agreement non-performance settlements.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The nuclear fleet capacity factor, which excludes Salem, increased primarily due to a lower number of outage days. For 2010 and 2009, scheduled refueling outage days totaled 261 and 263, respectively, and non-refueling outage days totaled 57 and 78, respectively. Higher nuclear fuel costs and higher plant operating and maintenance costs, resulted in a higher production cost per MWh during 2010 as compared to 2009.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. The nuclear fleet capacity factor decreased primarily due to a higher number of outage days. For 2009 and 2008, refueling outage days totaled 263 and 241, respectively, and non-refueling outage days totaled 78 and 59, respectively. Higher nuclear fuel costs, partially offset by lower plant operating and maintenance costs resulted in a higher production cost per MWh during 2009 as compared to 2008.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2010 compared to 2009, consisted of the following:

	Increase (Decrease)
Impairment of certain generating assets [(a)]	$(223)
Announced plant shutdowns [(b)]	(21)
Nuclear insurance credits [(c)]	(20)
2009 restructuring plan severance charges	(11)
Asset retirement obligation reduction [(d)]	51
Wages and other benefits	33
Pension and non-pension postretirement benefits expense	21
Nuclear refueling outage costs, including the co-owned Salem Plant	20
Exelon Wind acquisition [(e)]	11
Other	13
Decrease in operating and maintenance expense	$(126)

(a) Reflects the impairment of certain generating assets in 2009. See Note 5 of the Combined Notes to Consolidated Financial Statements for further information.
(b) Primarily reflects severance-related and inventory write-down costs incurred in 2009 associated with the announced plant shutdowns. See Note 14 of the Combined Notes to Consolidated Financial Statements for further information.
(c) Reflects the impact of the return of property and business interruption insurance premiums in 2010. No premiums were returned for 2009.
(d) Primarily reflects the reduction in the ARO in excess of the related ARC balances for the non-regulatory agreement units during 2009.
(e) See Note 3 of the Combined Notes to Consolidated Financial Statements for further information.

The changes in operating and maintenance expense for 2009 compared to 2008, consisted of the following:

	Increase (Decrease)
Impairment of certain generating assets [(a)]	$223
Pension and non-pension postretirement benefits expense	92
Nuclear insurance credits [(b)]	28
Announced plant shutdowns [(c)]	24
Nuclear refueling outage costs, including the co-owned Salem Plant [(d)]	(46)
Labor, other benefits, contracting and materials [(e)]	(35)
Asset retirement obligation reduction [(f)]	(26)
Accounts receivable reserve [(g)]	(22)
Other	(17)
Increase in operating and maintenance expense	$221

(a) Reflects the impairment of certain generating assets in 2009. See Note 5 of the Combined Notes to Consolidated Financial Statements for further information.
(b) Reflects the impact of the return of property and business interruption insurance premiums in 2008. No premiums were returned for 2009.
(c) Reflects severance-related and inventory write-down costs incurred in 2009 associated with the announced plant shutdowns. See Note 14 of the Combined Notes to Consolidated Financial Statements for further information.
(d) Primarily reflects the impact of decreased planned and unplanned nuclear outage days in 2009.
(e) Primarily reflects the impact of Exelon's 2009 cost savings program.
(f) Primarily reflects an increased reduction in the ARO in excess of the related ARC balances for the Non-Regulatory Agreement Units during 2009 as compared to 2008.
(g) Reflects the impact of an increase in accounts receivable reserves recorded in 2008 as a result of Generation's direct net exposure to Lehman Brothers Holdings, Inc.

Depreciation and Amortization

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. For 2010 as compared to 2009, the increase in depreciation and amortization expense was a result of a change in the estimated useful lives of the plants associated with the 2009 announced shutdowns further described in Note 14 of the Combined Notes to Consolidated Financial Statements, which resulted in a depreciation expense increase of $48 million. Additionally, Generation completed a depreciation rate study during the first quarter of 2010, which resulted in a change in depreciation rate. The change in depreciation rate resulted in an increase of $21 million. The remaining increase was primarily due to higher plant balances due to capital additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages).

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. For 2009 as compared to 2008, the increase in depreciation and amortization expense was a result of a change in the estimated useful lives of the plants associated with the 2009 announced shutdowns, which resulted in $32 million of accelerated depreciation expense. Additionally, the change in the estimated useful life of a fossil-fired power plant in 2008 resulted in $18 million higher depreciation expense in 2009. The remaining increase was primarily due to higher plant balances due to capital additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages), partially offset by the impact of the reassessment of the useful lives of several other fossil-fired facilities in 2008 and reduced depreciation expense associated with the generating assets impaired in 2009.

Taxes Other Than Income

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. For 2010 as compared to 2009, the increase was primarily due to increased property taxes related to Generation's nuclear facilities.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. For 2009 as compared to 2008, the increase was primarily due to a $9 million gross receipts tax adjustment in 2008.

Interest Expense

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. For 2010 as compared to 2009, the increase in interest expense is primarily due to the debt issuances in 2010, further described in Note 10 of the Combined Notes to Consolidated Financial Statements. The increase in long-term debt resulted in higher interest expense of approximately $42 million.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. For 2009 as compared to 2008, the decrease in interest expense reflects lower interest of $16 million on SNF obligations as a result of lower rates. Interest on the spent fuel obligation accrues at the 13-week Treasury Rate and is recalculated on a quarterly basis. See Note 18 of the Combined Notes to Consolidated Financial Statements for further information. Additionally, the decrease in interest expense reflects a $16 million increase in capitalized interest during 2009 as compared to 2008. These decreases in interest expense were partially offset by a $9 million increase in interest expense related to uncertain tax positions.

Other, Net

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. For 2010 as compared to 2009, the decrease primarily reflects lower net unrealized gains on the NDT funds of its Non-Regulatory Agreement Units. See the table below for additional information. Additionally, the decrease reflects the contractual elimination of $96 million of income tax expense associated with the NDT funds of the Regulatory Agreement Units in 2010 compared to the contractual elimination of $181 million of income tax expense in 2009. These decreases are partially offset by the impacts of $71 million of expense related to long-term debt extinguished in the third and fourth quarter of 2009 further described in Note 10 of the Combined Notes to Consolidated Financial Statements.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. For 2009 as compared to 2008, the increase reflects net unrealized gains in 2009 on the NDT funds of its Non-Regulatory Agreement Units as compared to net unrealized losses in 2008. See the table below for additional information. Additionally, the increase reflects the contractual elimination of $181 million of income tax expense associated with the NDT funds of the Regulatory Agreement Units in 2009 compared to the contractual elimination of $202 million of income tax benefit in 2008. These increases are partially offset by the impacts of income in 2008 related to the termination of a gas supply guarantee and $71 million of expense related to long-term debt extinguished in the third and fourth quarters of 2009.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for 2010, 2009 and 2008:

	2010	2009	2008
Net unrealized gains (losses) on decommissioning trust funds—Non-Regulatory Agreement Units	$104	$227	$(324)
Net realized gains (losses) on sale of decommissioning trust funds—Non-Regulatory Agreement Units	$ 2	$ (19)	$ (39)

Effective Income Tax Rate.

Generation's effective income tax rates for the years ended December 31, 2010, 2009 and 2008 were 37.4%, 40.3% and 33.4%, respectively. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—ComEd

	2010	2009	Favorable (unfavorable) 2010 vs. 2009 variance	2008	Favorable (unfavorable) 2009 vs. 2008 variance
Operating revenues	$6,204	$5,774	$ 430	$6,136	$(362)
Purchased power expense	3,307	3,065	(242)	3,582	517
Revenue net of purchased power expense [(a)]	2,897	2,709	188	2,554	155
Other operating expenses					
Operating and maintenance	975	1,028	53	1,097	69
Operating and maintenance for regulatory required programs	94	63	(31)	28	(35)
Depreciation and amortization	516	494	(22)	464	(30)
Taxes other than income	256	281	25	298	17
Total other operating expenses	1,841	1,866	25	1,887	21
Operating income	1,056	843	213	667	176
Other income and deductions					
Interest expense, net	(386)	(319)	(67)	(348)	29
Loss in equity method investments	—	—	—	(8)	8
Other, net	24	79	(55)	18	61
Total other income and deductions	(362)	(240)	(122)	(338)	98
Income before income taxes	694	603	91	329	274
Income taxes	357	229	(128)	128	(101)
Net income	$ 337	$ 374	$ (37)	$ 201	$ 173

(a) ComEd evaluates its operating performance using the measure of revenue net of purchased power expense. ComEd believes that revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this Financial Information supplement.

Net Income

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The decrease in ComEd's net income is primarily due to the remeasurement of uncertain income tax positions in 2009 and 2010 related to the 1999 sale of ComEd's fossil generating assets. These remeasurements resulted in increased interest expense and income tax expense recorded in 2010, and increased interest income recorded in 2009. Net income was also reduced by higher incremental storm costs, higher depreciation and amortization expense reflecting higher plant balances, and the impact of Federal health care legislation signed into law in March

2010. These reductions to net income were partially offset by higher revenue net of purchased power expense primarily due to favorable weather conditions, a net reduction in operating and maintenance expense, and the accrual of estimated future refunds of the Illinois utility distribution tax for the 2008 and 2009 tax years.

The reduction in operating and maintenance expenses reflects the February 2010 approval by the ICC of ComEd's uncollectible accounts expense rider mechanism, the reduction of ComEd's ARO reserve in 2010, and a charge in 2009 for severance expense incurred as a cost to achieve savings under Exelon's 2009 company-wide cost savings initiative.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. The increase in ComEd's net income was driven primarily by higher revenue net of purchased power expense, reflecting increased distribution rates effective September 16, 2008 due to an ICC rate order, partially offset by a decline in electric deliveries, primarily resulting from unfavorable weather conditions and reduced load in 2009. In addition, ComEd's increase in net income reflected lower operating and maintenance expenses, lower interest expense, and higher interest income related to the 2009 remeasurement of uncertain income tax positions.

The reduction in operating and maintenance expenses reflected Exelon's 2009 company-wide cost savings initiative. The initiative included job reductions, for which ComEd recorded a charge for severance expense as a cost to achieve these savings. ComEd also benefited from decreased storm expenses. Operation and maintenance expenses reflected increased pension and other postretirement benefits expenses due to lower than expected pension and postretirement plan asset returns in 2008. In the September 2008 rate case ruling, the ICC mandated fixed asset disallowances while allowing certain regulatory assets, which were recorded as a net one-time charge in 2008.

Depreciation and amortization expenses increased due to higher plant balances and new depreciation rates which became effective January 1, 2009. ComEd experienced a decrease in interest expense primarily due to lower outstanding debt in 2009.

Operating Revenues Net of Purchased Power Expense

There are certain drivers to revenue that are fully offset by their impact on purchased power expense, such as commodity procurement costs and customer choice programs. ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on electric revenue net of purchased power expense. See Note 2 of the Combined Notes to Consolidated Financial Statements for information on ComEd's electricity procurement process.

Electric revenues and purchased power expense are affected by fluctuations in customers' purchases from competitive electric generation suppliers. All ComEd customers have the ability to purchase electricity from an alternative electric generation supplier. The customer choice of electric generation supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied electricity. The number of retail customers purchasing electricity from competitive electric generation suppliers was 66,200 and 53,400 at December 31, 2010 and 2009, respectively, representing 52% of ComEd's annual retail kWh sales.

The changes in ComEd's electric revenue net of purchased power expense for 2010 compared to 2009 consisted of the following:

	Increase (Decrease)
Weather—delivery	$ 89
Uncollectible Accounts Recovery	59
Energy Efficiency and Demand Response Programs	26
Rider SMP Revenues	11
Rate Relief Programs	7
2007 City of Chicago Settlement	5
Volume—delivery	(3)
Revenues Subject to Refund (2007 Rate Case)	(17)
Other	11
Total increase	$188

Weather—Delivery

Revenues net of purchased power expense were higher in 2010 compared to 2009 due to favorable weather conditions. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions" because these weather conditions result in increased customer usage and delivery of electricity. Conversely, mild weather reduces demand.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory. The changes in heating and cooling degree days in ComEd's service territory consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2010**	**2009**	**Normal**	**From 2009**	**From Normal**
Heating Degree-Days	5,991	6,429	6,362	(6.8)%	(5.8)%
Cooling Degree-Days	1,181	589	855	100.5%	38.1%

Uncollectible Accounts Recovery

In 2009, comprehensive legislation was enacted into law in Illinois providing public utility companies with the ability to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and amounts collected in rates annually through a rider mechanism, starting with 2008 and prospectively. Recovery began in April 2010. During 2010, ComEd recognized recovery of $59 million associated with this rider mechanism. This amount was offset by an equal amount of amortization of regulatory assets reflected in operating and maintenance expense.

Energy Efficiency and Demand Response Programs

As a result of the Illinois Settlement Legislation, utilities are required to provide energy efficiency and demand response programs and other programs, and are allowed recovery of the costs of these programs from customers on a full and current basis through a reconcilable automatic adjustment clause. During 2010, ComEd recognized $85 million of revenue associated with these programs, compared to $59 million in 2009. These amounts were offset by equal amounts in operating and maintenance expense for regulatory required programs. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Rider SMP Revenues

In October 2009, the ICC approved ComEd's proposed AMI pilot program, with minor modifications, and recovery of substantially all program costs from customers via Rider SMP. During 2010, ComEd recognized $11 million of revenue associated with this program. This amount was offset by operating and maintenance expense and depreciation expense of $11 million, which included a $4 million write off of the associated regulatory asset as a result of the September 30, 2010 ruling by the Illinois Appellate Court which denied future recover of ComEd's AMI pilot program costs. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information on the Illinois Appellate Court ruling.

Rate Relief Programs

ComEd funded less rate relief credits to customers in 2010 compared to 2009. Credits provided to customers are recorded as a reduction to operating revenues; therefore, the reduction in credits resulted in an increase in revenues net of purchased power expense for 2010 compared to 2009. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

2007 City of Chicago Settlement

ComEd paid $3 million and $8 million in 2010 and 2009, respectively, under the terms of its 2007 settlement agreement with the City of Chicago. Payments were recorded as a reduction to revenues; therefore, the lower payment in 2010 resulted in a net increase in revenues net of purchased power expense for 2010 compared to 2009.

Volume—Delivery

Revenues net of purchased power expense, exclusive of the effects of weather, decreased primarily as a result of lower delivery volume to residential customers in 2010 as compared to 2009.

Revenues Subject to Refund (2007 Rate Case)

ComEd recorded an estimated refund obligation of $17 million in 2010 as a result of the September 30, 2010 Illinois Appellate Court ruling regarding the treatment of post-test year accumulated depreciation in the 2007 Rate Case. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Other

Other revenues were higher in 2010 compared to 2009. Other revenues include revenues related to late payment charges, rental revenue, franchise fees, transmission revenues and recoveries of environmental remediation costs associated with MGP sites.

The changes in ComEd's electric revenue net of purchased power expense for 2009 compared to 2008 consisted of the following:

	Increase (Decrease)
Distribution Pricing	$214
Energy Efficiency and Demand Response Programs	34
2007 City of Chicago Settlement	10
Transmission	(26)
Volume—delivery	(40)
Weather—delivery	(45)
Other	8
Total increase	$155

Distribution Pricing

The increase in retail electric revenues net of purchased power expense as a result of distribution pricing in 2009 compared to the same period in 2008, reflected the impact of the 2007 Rate Case. The ICC issued an order in the 2007 Rate Case approving a $274 million increase in ComEd's annual revenue requirement. The order became effective September 16, 2008 resulting in increased distribution revenues in 2009 compared to 2008. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Energy Efficiency and Demand Response Programs

As a result of the Illinois Settlement Legislation, utilities are required to provide energy efficiency and demand response programs beginning June 1, 2008 and are allowed recovery of the costs of these programs from customers on a full and current basis through a reconcilable automatic adjustment clause. In 2009, ComEd recognized $59 million of revenue associated with these programs, compared to $25 million in 2008. These amounts were offset by equal amounts in operating and maintenance expense for regulatory required programs. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

2007 City of Chicago Settlement

ComEd paid $8 million and $18 million in 2009 and 2008, respectively, under the terms of its 2007 settlement agreement with the City of Chicago. Payments were recorded as a reduction to revenues; therefore, the lower payment in 2009 resulted in a net increase in revenues net of purchased power expense for 2009 compared to 2008.

Transmission

Transmission revenues net of purchased power expense decreased primarily due to a FERC order issued in 2008, which approved incentive recovery treatment of ComEd's largest transmission project. The cumulative recognition in 2008 of the 2007 effects of this order resulted in higher revenues in 2008 compared to 2009. This was partially offset by the impact of higher transmission rates effective June 1, 2008 and June 1, 2009, resulting from ComEd's FERC approved formula rate. See Note 2 of the Combined Notes to Consolidated Financial Statements for more information.

Volume—delivery

The decrease in revenues net of purchased power expense as a result of lower delivery volume, exclusive of the effects of weather, in 2009 as compared to 2008, reflected decreased average usage per customer and fewer customers in the ComEd service territory.

Weather—delivery

Revenues net of purchased power expense were lower due to unfavorable weather conditions in 2009 compared to 2008. The changes in heating and cooling degree days in ComEd's service territory consisted of the following:

				% Change	
Heating and Cooling Degree-Days (a)	**2009**	**2008**	**Normal**	**From 2008**	**From Normal**
Heating Degree-Days	6,429	6,680	6,362	(3.8)%	1.1 %
Cooling Degree-Days	589	828	855	(28.9)%	(31.1)%

(a) Reflects the impact of the leap year day in 2008.

Other

Other revenues were higher in 2009 compared to 2008. Other revenues include revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs and recoveries of environmental remediation costs associated with MGP sites.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2010 compared to 2009, consisted of the following:

	Increase (Decrease)
Uncollectible accounts expense (a):	
Amortization (b)	$ 59
One-time impact of 2010 ICC Order (c)	(60)
Provision (d)	(37)
(Under) over-recovered	(3)
	(41)
Storm-related costs	20
Pension and non-pension postretirement benefits expense	7
Injuries and damages	6
Fringe benefits	5
Rider SMP regulatory asset write off (e)	4
Contracting	(6)
Wages and other benefits	(7)
Corporate allocations	(8)
ARO adjustment	(10)
2009 restructuring plan severance charges	(19)
Other	(4)
Decrease in operating and maintenance expense	$(53)

(a) On February 2, 2010, the ICC issued an order adopting ComEd's proposed tariffs filed in accordance with Illinois legislation providing public utilities the ability to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and amounts collected in rates annually through a rider mechanism starting with 2008 and prospectively.

(b) In 2010, ComEd recovered $59 million of operating revenues through its uncollectible accounts expense rider mechanism. An equal amount of amortization of regulatory assets was recorded in operating and maintenance expense. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

(c) As a result of the February 2010 ICC order, ComEd recorded a regulatory asset of $70 million and an offsetting reduction in operating and maintenance expense for the cumulative under-collections in 2008 and 2009. In addition, ComEd recorded a one time contribution of $10 million associated with this legislation.

(d) Uncollectible accounts expense decreased in 2010 compared to 2009 as a result of ComEd's increased collection activities.

(e) In 2010, ComEd recorded a write off to operation and maintenance expense of the regulatory asset associated with the AMI pilot program of $4 million as a result of the September 30, 2010 Illinois Appellate Court ruling. In addition, ComEd recorded $5 million of operation and maintenance for regulatory required programs, and $2 million of depreciation expense associated with the AMI pilot program. In 2010, ComEd recorded $11 million of operating revenues associated with the AMI pilot program recovered under Rider SMP. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information on the Illinois Appellate Court ruling.

The changes in operating and maintenance expense for 2009 compared to 2008, consisted of the following:

	Increase (Decrease)
Pension and non-pension postretirement benefits expense	$ 51
Severance	19
Provision for uncollectible accounts [(a)]	14
Injuries and damages	(1)
Rate Relief Programs	(6)
Corporate allocations	(7)
Fringe benefits	(7)
Wages and salaries	(26)
Contracting and materials	(32)
2007 Rate Case disallowances [(b)]	(22)
Storm-related costs	(40)
Other	(12)
Decrease in operating and maintenance expense	$(69)

(a) Uncollectable accounts expense increased in part as a result of the current overall negative economic conditions, partially mitigated by ComEd's increased collection activities in 2009.
(b) In September 2008, as a result of the 2007 Rate Case order, ComEd recorded $37 million of fixed asset disallowances; $35 million was recorded as operating and maintenance expense and $2 million was recorded as depreciation expense. In addition, ComEd established regulatory assets of $13 million associated with reversing previously incurred expenses.

Operating and maintenance expense for regulatory required programs

Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through a reconcilable automatic adjustment clause. An equal and offsetting amount has been reflected in operating revenues during the period.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. In 2010, expenses related to energy efficiency and demand response programs and purchased power administration costs consisted of $85 million and $4 million, respectively, compared to $59 million and $4 million, respectively, for 2009. In 2010, expenses related to ComEd's AMI pilot program were $5 million. Such amount excludes a write off to operation and maintenance expense of the regulatory asset associated with the AMI pilot program of $4 million as a result of the September 30, 2010 Illinois Appellate Court ruling and $2 million of depreciation expense. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. In 2009, expenses related to energy efficiency and demand response programs and purchased power administration costs consisted of $59 million and $4 million, respectively, compared to $25 million and $3 million, respectively, for 2008. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2010 compared to 2009 and 2009 compared to 2008, consisted of the following:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
Depreciation expense associated with higher plant balances	$ 16(a)	$25(b)
2007 Rate Case asset disallowances	—	(2)
Other amortization expense	6	7
Increase in depreciation and amortization expense	$ 22	$30

(a) Depreciation and amortization expense increased in 2010 compared to 2009 due to higher plant balances.
(b) Depreciation and amortization expense increased in 2009 compared to 2008 due to higher plant balances and changes to useful lives of assets based on a depreciation rate study, which became effective January 1, 2009.

Taxes Other Than Income

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. Taxes other than income taxes decreased in 2010 compared to 2009 reflecting the accrual of estimated future refunds of Illinois utility distribution tax recorded in 2010 for the 2008 and 2009 tax years. Historically, ComEd has recorded refunds of the Illinois utility distribution tax when received. ComEd believes it now has sufficient, reliable evidence to record and support an estimated receivable associated with the anticipated refund for the 2008 and 2009 tax years.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. Taxes other than income decreased for 2009 compared to 2008 primarily as a result of $9 million of property tax settlements recorded in 2009. These settlements will result in lower rates prospectively.

Interest Expense, Net

The changes in interest expense for 2010 compared to 2009 and 2009 compared to 2008 consisted of the following:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
Uncertain income tax positions remeasurement (a)(f)	$65	$ (6)
Interest expense on debt (including financing trusts) (b)(c)	5	(20)
Interest expense related to uncertain tax positions (d)	(4)	6
Other (e)	1	(9)
Increase (decrease) in interest expense, net	$67	$(29)

(a) During 2009, ComEd recorded $66 million of interest benefit associated with the remeasurement of income tax positions, specifically related to the 1999 Sale of Fossil Generating Assets, of which, $6 million was recorded as a reversal of interest expense with the remainder recorded in Other, net. See Note 11 of the Combined Notes to Consolidated Financial Statements for more information.
(b) In 2008, interest expense included a $7 million charge to reverse previously recognized AFUDC resulting from the January 18, 2008 FERC order granting incentive treatment on ComEd's largest transmission project.
(c) ComEd Financing II and ComEd Transitional Funding Trust were dissolved in 2008.
(d) During 2008, ComEd recorded an increase in interest expense of $6 million related to a settlement with the IRS of a research and development claim.
(e) Primarily reflects the decrease in interest for short term borrowings in 2009 compared to 2008.
(f) During 2010, ComEd recorded $59 million of interest expense associated with the remeasurement of uncertain income tax positions related to the 1999 sale of Fossil Generating Assets.

Other, Net

The changes in Other, net for 2010 compared to 2009 and 2009 compared to 2008 consisted of the following:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
Interest income related to uncertain tax positions [(a)]	$(59)	$59
Gain on disposal of assets and investments	(5)	5
Other-than-temporary impairment of investments	7	(7)
Other	2	4
(Decrease) increase in Other, net	$(55)	$61

(a) During 2009, ComEd recorded $66 million of interest benefit associated with the remeasurement of income tax positions, specifically related to the 1999 Sale of Fossil Generating Assets, of which, $6 million was recorded as a reversal of interest expense with the remainder recorded in Other, net. See Note 11 of the Combined Notes to Consolidated Financial Statements for more information.

Effective Income Tax Rate

ComEd's effective income tax rate for the years ended December 31, 2010, 2009 and 2008 was 51.4%, 38.0% and 38.9%, respectively. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2010	2009	% Change 2010 vs 2009	Weather-Normal % Change	2008	% Change 2009 vs 2008	Weather-Normal % Change
Retail Delivery and Sales [(a)]							
Residential	29,171	26,621	9.6%	(1.2)%	28,389	(6.2)%	(1.4)%
Small commercial & industrial	32,904	32,234	2.1%	(0.6)%	33,487	(3.7)%	(2.2)%
Large commercial & industrial	27,717	26,668	3.9%	2.6%	28,809	(7.4)%	(6.7)%
Public authorities & electric railroads	1,273	1,237	2.9%	2.4%	1,214	1.9%	2.0%
Total Retail	91,065	86,760	5.0%	0.2%	91,899	(5.6)%	(3.3)%

Number of Electric Customers	As of December 31, 2010	2009	2008
Residential	3,438,677	3,425,570	3,438,065
Small commercial & industrial	363,393	360,779	359,026
Large commercial & industrial	2,005	1,985	2,072
Public authorities & electric railroads	5,078	5,008	5,075
Total	3,809,153	3,793,342	3,804,238

Electric Revenue	2010	2009	% Change 2010 vs 2009	2008	% Change 2009 vs 2008
Retail Delivery and Sales [(a)]					
Residential	$3,549	$3,115	13.9%	$3,284	(5.1)%
Small commercial & industrial	1,639	1,660	(1.3)%	1,831	(9.3)%
Large commercial & industrial	397	387	2.6%	385	0.5%
Public authorities & electric railroads	62	57	8.8%	59	(3.4)%
Total Retail	5,647	5,219	8.2%	5,559	(6.1)%
Other Revenue [(b)]	557	555	0.4%	577	(3.8)%
Total Electric Revenues	$6,204	$5,774	7.4%	$6,136	(5.9)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy.
(b) Other revenue primarily includes transmission revenue from PJM.

Results of Operations—PECO

	2010	2009	Favorable (unfavorable) 2010 vs. 2009 variance	2008	Favorable (unfavorable) 2009 vs. 2008 variance
Operating revenues	$5,519	$5,311	$ 208	$5,567	$(256)
Purchased power and fuel	2,762	2,746	(16)	3,018	272
Revenue net of purchased power and fuel [(a)]	2,757	2,565	192	2,549	16
Other operating expenses					
Operating and maintenance	680	640	(40)	731	91
Operating and maintenance for regulatory required programs	53	—	(53)	—	—
Depreciation and amortization	1,060	952	(108)	854	(98)
Taxes other than income	303	276	(27)	265	(11)
Total other operating expenses	2,096	1,868	(228)	1,850	(18)
Operating income	661	697	(36)	699	(2)
Other income and deductions					
Interest expense, net	(193)	(187)	(6)	(226)	39
Loss in equity method investments	—	(24)	24	(16)	(8)
Other, net	8	13	(5)	18	(5)
Total other income and deductions	(185)	(198)	13	(224)	26
Income before income taxes	476	499	(23)	475	24
Income taxes	152	146	(6)	150	4
Net income	324	353	(29)	325	28
Preferred security dividends	4	4	—	4	—
Net income on common stock	$ 320	$ 349	$ (29)	$ 321	$ 28

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this Financial Information supplement.

Net Income

Year ended December 31, 2010 Compared to Year Ended December 31, 2009. The decrease in net income was primarily driven by increased operating expenses partially offset by increased electric revenues net of purchased power expense. The increase in operating expenses reflected higher storm costs and increased scheduled CTC amortization expense. Electric revenues net of purchased power expense increased as a result of favorable weather conditions and increased CTC recoveries.

Year ended December 31, 2009 Compared to Year Ended December 31, 2008. The increase in net income was driven primarily by increased operating revenue net of purchased power and fuel expense and decreased interest expense, which was partially offset by increased operating expenses. The increase in revenue net of purchased power and fuel expense was primarily related to increased gas distribution rates effective January 1, 2009, which were partially offset by reduced electric load.

PECO's operating expenses increased as a result of increased scheduled CTC amortization expense and pension and other postretirement benefits expense due to lower than expected pension and postretirement plan asset returns in 2008. The increased operating expenses were partially offset by decreased allowance for uncollectible accounts expense.

Operating Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and customer choice programs. Gas revenues and fuel expense are affected by fluctuations in natural gas procurement costs. PECO's purchased natural gas cost rates charged to customers are subject to quarterly adjustments designed to recover or refund the difference between the actual cost of purchased natural gas and the amount included in rates in accordance with the PAPUC's PGC. Therefore, fluctuations in natural gas procurement costs have no impact on gas revenue net of fuel expense. The average purchased gas cost rate per mmcf was $7.66, $8.80 and $11.31 for the years ended December 31, 2010, 2009 and 2008, respectively. PECO's electric generation rates charged to customers were capped until December 31, 2010 in accordance with the 1998 restructuring settlement. Under PECO's full requirements PPA with Generation, which expired on December 31, 2010, purchased power costs were based on the energy component of the rates charged to customers. Electric revenues and purchased power expense fluctuate in relation to customer class usage as each customer class was charged a different capped electric generation rate; however, there is no impact on electric revenue net of purchased power expense.

Electric revenues and purchased power expense are also affected by fluctuations in customer choice program participation. All PECO customers have the choice to purchase energy from a competitive electric generation supplier. This choice does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy. The number of retail customers purchasing energy from a competitive electric generation supplier was 36,600, 21,700 and 24,800 at December 31, 2010, 2009 and 2008, respectively, representing 2%, 1% and 2% of total retail customers, respectively. Due to PECO's transition to market-based procurement of electric supply on January 1, 2011, the number of customers that choose to purchase generation service from a competitive electric generation supplier is expected to increase in the first quarter of 2011 and beyond.

The changes in PECO's operating revenues net of purchased power and fuel expense for the year ended December 31, 2010 compared to the same period in 2009 consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
Weather	$ 81	$ (2)	$ 79
CTC recoveries	66	—	66
Regulatory required programs cost recovery	59	—	59
Pricing	6	—	6
Other	(17)	(1)	(18)
Total increase (decrease)	$195	$ (3)	$192

Weather

The demand for electricity and gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. Electric revenues net of purchased power expense were higher due to favorable weather conditions during the summer months of 2010 in PECO's service territory. The increase was partially offset by the lower gas revenues net of fuel expense primarily as a result of unfavorable weather conditions in the winter months of 2010 compared to 2009.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the year ended December 31, 2010 compared to the same period in 2009 and normal weather consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2010**	**2009**	**Normal**	**From 2009**	**From Normal**
Heating Degree-Days	4,396	4,534	4,638	(3.0)%	(5.2)%
Cooling Degree-Days	1,817	1,246	1,292	45.8%	40.6%

CTC Recoveries

The increase in electric revenues net of purchased power expense as a result of CTC recoveries reflected a scheduled increase to the CTC component of the capped generation rates charged to customers, which resulted in a decrease to the energy component and reduced purchase power expense under the PPA. Due to the lower than expected sales volume in 2009, the CTC increase was necessary to ensure full recovery of stranded costs during the final year of the transition period that expired on December 31, 2010.

Regulatory Required Programs Cost Recovery

The increase in electric revenues relating to regulatory required programs was due to the recovery of $56 million and $3 million in costs associated with the energy efficiency program and the consumer education program, respectively, which included $6 million related to gross receipts taxes. The costs of these programs are recoverable from customers on a full and current basis through approved regulated rates and have been reflected in operating and maintenance expense for regulatory required programs during the period. The gross receipts tax revenues are offset by the corresponding gross receipts tax expense included in taxes other than income during the period.

Pricing

The increase in electric revenues net of purchased power expense as a result of pricing reflected an increase in the average price charged to commercial and industrial customers due to decreased usage per customer. The rates charged to customers decrease when usage exceeds a certain threshold.

Other

The decrease in other electric revenues net of purchased power expense primarily reflected decreased transmission revenue earned by PECO as a transmission owner for the use of PECO's transmission facilities in PJM.

The decrease in other gas revenues net of fuel expense primarily reflected lower late payment revenues in 2010 compared to 2009.

The changes in PECO's electric revenue net of purchased power expense and gas revenue net of fuel expense for the year ended December 31, 2009 compared to the same period in 2008 consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
Weather	$(15)	$ 3	$(12)
CTC recoveries	(42)		(42)
Gas distribution rate increase	—	77	77
Volume	(41)	(2)	(43)
Pricing	43	—	43
Other	(3)	(4)	(7)
Total increase (decrease)	$(58)	$ 74	$ 16

Weather

Electric revenues net of purchased power expense were lower due to the impact of unfavorable 2009 weather conditions in PECO's service territory and gas revenues net of fuel expense were higher due to the impact of unfavorable weather conditions in PECO's service territory in the winter months of 2008. The changes in heating and cooling degree days for the twelve months ended 2009 and 2008, consisted of the following:

				% Change	
Heating and Cooling Degree-Days [(a)]	**2009**	**2008**	**Normal**	**From 2008**	**From Normal**
Heating Degree-Days	4,534	4,403	4,638	3.0%	(2.2)%
Cooling Degree-Days	1,246	1,354	1,292	(8.0)%	(3.6)%

(a) Reflects the impact of the leap year day in 2008

CTC Recoveries

The decrease in electric revenues net of purchased power expense related to CTC recoveries was a result of lower delivery volumes due to unfavorable weather conditions and decreased usage across all customer classes.

Gas distribution rate increase

The increase in gas revenues net of fuel expense reflected increased distribution rates effective January 1, 2009 resulting from the settlement of the 2008 gas distribution rate case.

Volume

The decrease in revenues net of purchased power and fuel expense as a result of lower delivery volume, exclusive of the effects of weather, reflected decreased electric usage per customer across all customer classes as well as decreased gas usage across the small commercial and industrial customer class.

Pricing

The increase in electric revenues net of purchased power expense as a result of pricing reflected lower PECO electric distribution rates in 2008 due to the refund of the 2007 PURTA settlement to customers. The rate change had no impact on operating income because it was offset by the amortization of the regulatory liability related to the 2007 PURTA settlement reflected in taxes other than income.

Other

The increase in other electric revenues net of purchased power expense reflected an increase in revenues associated with volume shifts among customer classes, which resulted in a different profile of rates as different customer classes are charged different rates.

Operating and Maintenance Expense

The increase in operating and maintenance expense for 2010 compared to 2009 consisted of the following:

	Increase (Decrease)
Storm-related costs	$22
Salaries and other benefits	20
Uncollectible accounts expense	(3)
Severance	(3)
Other	4
Increase in operating and maintenance expense	$40

The decrease in operating and maintenance expense for 2009 compared to 2008 consisted of the following:

	Increase (Decrease)
Allowance for uncollectible accounts expense	$(97)
Storm-related costs	(9)
Materials and supplies	(3)
Pension and OPEB expense	11
Wages and salaries	5
Severance	3
Other	(1)
Decrease in operating and maintenance expense	$(91)

Operating and Maintenance for Regulatory Required Programs

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. Operating and maintenance expense related to regulatory required programs for the year ended December 31, 2010 consisted of costs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues during the current period. These expenses consisted of $50 million and $3 million related to energy efficiency and consumer education programs, which began in 2010.

Depreciation and Amortization Expense

The increase in depreciation and amortization expense for 2010 compared to 2009 and 2009 compared to 2008 consisted of the following:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
CTC amortization [(a)]	$ 98	$90
Other	10	8
Increase in depreciation and amortization expense	$108	$98

(a) The increase in PECO's scheduled CTC amortization recorded was in accordance with its 1998 restructuring settlement and was fully amortized as of December 31, 2010.

Taxes Other Than Income

The increase in taxes other than income for 2010 compared to 2009 and in 2009 compared to 2008 consisted of the following:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
PURTA amortization [(a)]	$ 2	$ 34
Taxes on utility revenues [(b)]	22	(22)
Other	3	(1)
Increase in taxes other than income	$27	$ 11

(a) The increase in taxes other than income related to PURTA amortization reflects the impact of regulatory liability amortization recorded in 2009 and 2008 that offset the distribution rate reduction made to refund the 2007 PURTA settlement to customers.
(b) The increase in tax expense for 2010 compared to 2009 reflected increased gross receipts tax as a result of higher revenue. The decrease in tax expense for 2009 compared to 2008 was due to a gross receipts tax rate reduction that became effective on January 1, 2009.

Interest Expense, Net

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The increase in interest expense, net for 2010 compared to 2009 was primarily due to a change in measurement of uncertain tax positions in accordance with accounting guidance. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information. This increase was partially offset by a decrease in interest expense resulting from the retirement of the PETT transition bonds on September 1, 2010. See Note 1 of the Combined Notes to Consolidated Financial Statements for further information.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. The decrease in interest expense, net for 2009 compared to 2008 was primarily due to a decrease in the outstanding debt balance owed to PETT, partially offset by an increase in interest expense associated with a higher amount of outstanding long-term first and refunding mortgage bonds.

Loss in Equity Method Investments

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The decrease in the loss in equity method investments for 2010 compared to 2009 was due to the consolidation of PETT in accordance with authoritative guidance for the consolidation of variable interest entities effective January 1, 2010. PETT was dissolved on September 20, 2010. See Note 1 of the Combined Notes to Consolidated Financial Statements for further information.

Other, Net

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The decrease in Other, net for 2010 compared to 2009 was primarily due to decreased investment income and a decrease in interest income related to a change in measurement of uncertain income tax positions in 2010. See Note 11 of the Combined Notes to Consolidated Financial Statements for further information.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008. The decrease in Other, net for 2009 compared to 2008 was primarily due to the impact of interest income recorded in 2009 related to the SSCM settlement. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional details of the components of Other, net.

Effective Income Tax Rate

PECO's effective income tax rates for the years ended December 31, 2010, 2009 and 2008 were 31.9%, 29.3% and 31.6%, respectively. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2010	2009	% Change 2010 vs. 2009	Weather-Normal % Change	2008	% Change 2009 vs. 2008	Weather-Normal % Change
Retail Delivery and Sales [(a)]							
Residential	13,913	12,893	7.9%	0.5%	13,317	(3.2)%	(2.3)%
Small commercial & industrial	8,503	8,397	1.3%	(1.9)%	8,680	(3.3)%	(2.4)%
Large commercial & industrial	16,372	15,848	3.3%	0.8%	16,477	(3.8)%	(3.1)%
Public authorities & electric railroads	925	930	(0.5)%	(0.3)%	909	2.3%	2.3%
Total Electric Retail	39,713	38,068	4.3%	0.1%	39,383	(3.3)%	(2.6)%

Number of Electric Customers	As of December 31, 2010	2009	2008
Residential	1,411,643	1,404,416	1,405,532
Small commercial & industrial	156,865	156,305	156,309
Large commercial & industrial	3,071	3,094	3,088
Public authorities & electric railroads	1,102	1,085	1,085
Total	1,572,681	1,564,900	1,566,014

Electric Revenue	2010	2009	% Change 2010 vs. 2009	2008	% Change 2009 vs. 2008
Retail Delivery and Sales [(a)]					
Residential	$2,069	$1,859	11.3%	$1,918	(3.1)%
Small commercial & industrial	1,060	1,034	2.5%	1,053	(1.8)%
Large commercial & industrial	1,362	1,307	4.2%	1,406	(7.0)%
Public authorities & electric railroads	89	90	(1.1)%	87	3.4%
Total Retail	4,580	4,290	6.8%	4,464	(3.9)%
Other Revenue [(b)]	255	259	(1.5)%	282	(8.2)%
Total Electric Revenues	$4,835	$4,549	6.3%	$4,746	(4.2)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed delivery charges and a CTC. For customers purchasing electricity from PECO, revenue also reflects the cost of energy.

(b) Other revenue includes transmission revenue from PJM and other wholesale revenue.

PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2010	2009	% Change 2010 vs. 2009	Weather-Normal % Change	2008	% Change 2009 vs. 2008	Weather-Normal % Change
Retail sales	56,833	57,103	(0.5)%	0.9%	56,110	1.8%	(1.4)%
Transportation and other	30,911	27,206	13.6%	10.8%	27,624	(1.5)%	(1.2)%
Total Gas Deliveries	87,744	84,309	4.1%	4.1%	83,734	0.7%	(1.4)%

	As of December 31,		
Number of Gas Customers	2010	2009	2008
Residential	448,391	444,923	441,790
Commercial & industrial	41,303	40,991	40,830
Total Retail	489,694	485,914	482,620
Transportation	838	778	646
Total	490,532	486,692	483,266

Gas revenue	2010	2009	% Change 2010 vs. 2009	2008	% Change 2009 vs. 2008
Retail Delivery and Sales					
Retail sales	656	732	(10.4)%	795	(7.9)%
Transportation and other	28	30	(6.7)%	26	15.4%
Total Gas Deliveries	684	762	(10.2)%	821	(7.2)%

Liquidity and Capital Resources

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon, Generation, ComEd and PECO have access to unsecured revolving credit facilities with aggregate bank commitments of $957 million, $4.8 billion, $1 billion and $574 million, respectively. Credit facilities largely extend through October 2012 for Exelon, Generation and PECO. Exelon anticipates refinancing these credit facilities in the first half of 2011. The ComEd credit facility extends through March 2013. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See Note 10 of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements. The Registrants expect cash flows to be sufficient to meet operating expenses and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd and PECO operate in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy to wholesale customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers. ComEd's and PECO's cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO, gas distribution services to an established and diverse base of retail customers. ComEd's and PECO's future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, and their ability to achieve operating cost reductions. See Notes 2 and 18 of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. Exelon contributed $2.1 billion to its pension plans in January 2011, representing all currently planned 2011 qualified pension plan contributions, of which Generation, ComEd and PECO contributed $952 million, $871 million and $110 million, respectively. Exelon contributed $766 million and $441 million to its pension plans in 2010 and 2009, respectively. See Note 13 of the Combined Notes to Consolidated Financial Statements for the Registrants' 2010 and 2009 pension contributions.

Exelon's planned funding of the $2.1 billion in contributions includes $500 million from cash from operations, $750 million from the tax benefits of making the pension contributions and $850 million with the accelerated cash tax benefits from the 100% bonus depreciation provision enacted as part of the Tax Relief Act of 2010. These cash tax benefits will be realized over the course of 2011. As a result, the Registrants used other short-term liquidity sources and ComEd's January 2011 $600 million debt issuance, to fund a portion of the contribution on a short-term, interim basis until these cash tax benefits are realized.

Unlike the qualified pension plans, Exelon's other postretirement plans are not subject to regulatory minimum contribution requirements. Management considers several factors in determining the level of contributions to Exelon's other postretirement benefit plans, including levels of benefit claims paid and regulatory implications. Exelon expects to contribute $185 million to its other postretirement benefit plans in 2011, of which Generation, ComEd and PECO expect to contribute $85 million, $58 million and $29 million, respectively. Exelon contributed $203 million and $157 million in 2010 and 2009, respectively. These amounts do not reflect Federal prescription drug subsidy payments received of $10 million and $10 million in 2010 and 2009, respectively. See Note 13 of the Combined Notes to Consolidated Financial Statements for Exelon's 2010 and 2009 other postretirement benefit contributions.

See the "Contractual Obligations and Off-Balance Sheet Arrangements" section below for management's estimated future pension contributions.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- In the third quarter of 2010, Exelon and IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions. Under the terms of the preliminary agreement, Exelon estimates that the IRS will assess tax and interest of approximately $300 million in 2011, and that Exelon will receive additional tax refunds of approximately $270 million between 2011 and 2014. In order to stop additional interest from accruing on the IRS expected assessment, Exelon made a payment in December 2010 to the IRS of $302 million. During 2010, Exelon and IRS Appeals failed to reach a settlement with respect to the like-kind exchange position and the related substantial understatement penalty. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding potential cash flows impacts of a fully successful IRS challenge to Exelon's like-kind exchange position.

- The IRS anticipates issuing guidance in the first half of 2011 on the appropriate tax treatment of repair costs for electric transmission and distribution assets. Upon issuance of this guidance, ComEd and PECO will assess its impact, and if it results in a cash benefit to Exelon, ComEd and PECO will file a request for change in method of tax accounting for repair costs. PECO's approved 2010 electric and natural gas distribution rate case settlements stipulate that the expected cash benefit resulting from the application of the new methodology to prior tax years must be refunded to customers over a seven-year period. The prospective tax benefit claimed as a result of the new methodology should be reflected in tax expense in the year in which it is claimed on the tax return and will be reflected in the determination of revenue requirements in the next electric and natural gas distribution base rate cases.
- The Tax Relief Act of 2010, enacted into law on December 17, 2010, includes provisions accelerating the depreciation of certain property for tax purposes. Qualifying property placed into service after September 8, 2010, and before January 1, 2012, is eligible for 100% bonus depreciation. Additionally, qualifying property placed into service during 2012 is eligible for 50% bonus depreciation. These provisions will generate approximately $1 billion of cash for Exelon (approximately $850 million in 2011 and approximately $170 million in 2012). The cash generated is an acceleration of tax benefits that Exelon would have otherwise received over 20 years. Additionally, while the capital additions at ComEd and PECO generally increase future revenue requirements, the bonus depreciation associated with these capital additions will partially mitigate any future rate increases through the ratemaking process. See further details regarding the use of the cash generated in the "Pension and Other Postretirement Benefits" section above.
- Given the current economic environment, state and local governments are facing increasing financial challenges, which may increase the risk of additional income tax levies, property taxes, and other taxes.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the years ended December 31, 2010, 2009 and 2008:

	2010	2009	2010 vs. 2009 Variance	2008	2009 vs. 2008 Variance
Net income	$2,563	$2,707	$(144)	$2,737	$ (30)
Add (subtract):					
Non-cash operating activities (a)	4,340	3,930	410	3,400	530
Pension and non-pension postretirement benefit contributions	(959)	(588)	(371)	(230)	(358)
Income taxes	(543)	(29)	(514)	(38)	9
Changes in working capital and other noncurrent assets and liabilities (b)	122	(82)	204	(221)	139
Option premiums paid, net	(124)	(40)	(84)	(124)	84
Counterparty collateral received (posted), net	(155)	196	(351)	1,027	(831)
Net cash flows provided by operations	$5,244	$6,094	$(850)	$6,551	$(457)

(a) Represents depreciation, amortization and accretion, net mark-to-market gains on derivative transactions, deferred income taxes, provision for uncollectible accounts, pension and non-pension postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, and other non-cash charges.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

Cash flows provided by operations for 2010, 2009 and 2008 were as follows:

	2010	2009	2008
Exelon	$5,244	$6,094	$6,551
Generation	3,032	3,930	4,445
ComEd	1,077	1,020	1,079
PECO	1,150	1,166	969

Changes in Exelon's, Generation's, ComEd's and PECO's cash flows from operations were generally consistent with changes in their respective results of operations, as adjusted by changes in working capital in the normal course of business. In addition, significant operating cash flow impacts for the Registrants for 2010, 2009 and 2008 were as follows:

Generation

- During 2010, 2009 and 2008, Generation had net (postings) collections of counterparty collateral of $(1) million, $195 million and $1,029 million, respectively. Net collateral activity is primarily the result of changes in market conditions. Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted or collected from its counterparties. This collateral may be in various forms, such as cash, which may be obtained through the issuance of commercial paper, or letters of credit.
- During 2007, Generation, along with ComEd and other generators and utilities, reached an agreement with various representatives from the State of Illinois to address concerns about higher electric bills in Illinois. Generation committed to contributing approximately $747 million over four years. As part of the agreement, Generation contributed cash of approximately $23 million in 2010, $118 million in 2009 and $274 million in 2008. As of December 31, 2010, Generation had fulfilled its commitments under the Illinois Settlement Legislation.
- During 2010, 2009 and 2008, Generation's accounts receivable from ComEd (decreased) increased by $(65) million, $(28) million and $134 million, respectively, primarily due to changes in receivables for energy purchases related to its SFC, ICC-approved RFP contracts and financial swap contract.
- During 2010, 2009 and 2008, Generation's accounts receivable from PECO primarily due to the PPA increased by $74 million, $48 million and $5 million, respectively.
- During 2010, 2009 and 2008, Generation had net payments of approximately $124 million, $40 million and $124 million, respectively, related to purchases and sales of options. The level of option activity in a given year may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During 2010, 2009 and 2008, ComEd's payables to Generation (decreased) increased by $(65) million, $(28) million and $134 million, respectively, primarily due to changes in payables for energy purchases related to its SFC, ICC-approved RFP contracts and financial swap contract.
- During 2010, 2009 and 2008, ComEd's payables to other energy suppliers for energy purchases increased (decreased) by $58 million, $(68) million and $141 million, respectively.
- During 2010, ComEd posted $153 million of cash collateral to PJM. Prior to the second quarter of 2010, ComEd used letters of credit to cover all PJM collateral requirements.

PECO

- During 2010, 2009 and 2008, PECO's payables to Generation primarily due to the PPA increased by $74 million, $48 million and $5 million, respectively.
- During 2010, 2009 and 2008, PECO's payables to other energy suppliers for energy purchases increased (decreased) by $1 million, $(43) million and $(12) million, respectively. The 2009 decrease in payables to other energy suppliers is primarily due to an agreement executed in February 2009 between PECO, Generation and PJM that changed the way that PECO and Generation administer their PPA for default service.

Cash Flows used in Investing Activities

Cash flows used in investing activities for 2010, 2009 and 2008 were as follows:

	2010	2009	2008
Exelon [(a)(b)]	$(3,894)	$(3,458)	$(3,378)
Generation [(a)]	(2,896)	(2,220)	(1,967)
ComEd	(939)	(821)	(958)
PECO [(b)]	(120)	(377)	(377)

Capital expenditures for 2010, 2009 and 2008 and projected amounts for 2011 are as follows:

	Projected 2011	2010	2009	2008
Generation (c)	$2,562	$1,883	$1,977	$1,699
ComEd	1,015	962	854	953
PECO	448	545	388	392
Other (d)	18	(64)	54	73
Total Exelon capital expenditures	$4,043	$3,326	$3,273	$3,117

(a) Includes $893 million in 2010, related to the acquisition of Exelon Wind. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon Wind.
(b) Includes a cash inflow of $413 million as a result of the consolidation of PETT on January 1, 2010. See Note 1 of the Combined Notes to Consolidated Financial Statements for additional information.
(c) Includes nuclear fuel.
(d) Other primarily consists of corporate operations and BSC. The negative capital expenditures for Other in 2010 primarily relate to the transfer of information technology hardware and software assets from BSC to Generation, ComEd and PECO.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation. Approximately 40% of the projected 2011 capital expenditures at Generation are for the acquisition of nuclear fuel, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Included in the projected 2011 capital expenditures are a series of planned power uprates across the company's nuclear fleet. See "Executive Overview" for more information on nuclear uprates.

ComEd and PECO. Approximately 81% and 88% of the projected 2011 capital expenditures at ComEd and PECO, respectively, are for continuing projects to maintain and improve company operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as PECO's transmission system reliability upgrades required by PJM related to Generation's plant retirements. The remaining amounts are for capital additions to support new business and customer growth, which for PECO includes capital expenditures related to its smart meter program and SGIG project, net of DOE expected reimbursements. See Notes 2 and 5 of the Combined Notes to Consolidated Financial Statements for additional information. ComEd and PECO are each continuing to evaluate their total capital spending requirements. ComEd and PECO anticipate that they will fund their capital expenditures with internally generated funds and borrowings.

Cash Flows from Financing Activities

Cash flows used in financing activities for 2010, 2009 and 2008 were as follows:

	2010	2009	2008
Exelon	$(1,748)	$(1,897)	$(2,213)
Generation	(779)	(1,746)	(1,470)
ComEd	(179)	(155)	(161)
PECO	(811)	(525)	(587)

Debt. Debt activity for 2010, 2009 and 2008 by Registrant was as follows:

Company	Issuances of long-term debt in 2010	Use of proceeds
Generation	$900 million of Senior Notes, consisting of $550 million Senior Notes, 4.00% due October 1, 2020 and $350 million Senior Notes, 5.75% due October 1, 2041	Used to finance the acquisition of Exelon Wind and for general corporate purposes.
ComEd	$500 million of First Mortgage Bonds at 4.00% due August 1, 2020	Used to refinance First Mortgage Bonds, Series 102, which matured on August 15, 2010 and for other general corporate purposes.

Company	Issuances of long-term debt in 2009	Use of proceeds
Generation	$46 million of 3-year term rate Pollution Control Notes at 5.00% with a final maturity of December 1, 2042	Used to refinance $46 million of unenhanced tax-exempt variable rate debt that was repurchased on February 23, 2009. (a)
Generation	$1.5 billion of Senior Notes, consisting of $600 million of Senior Notes at 5.20% due October 1, 2019 and $900 million Senior Notes at 6.25% due October 1, 2039	Used to finance the purchase and optional redemption of Generation's 6.95% bonds due in 2011 and for general corporate purposes, including a distribution to Exelon to fund the purchase and optional redemption of Exelon's 6.75% Notes due in 2011 and to fund Generation's September 2009 repurchase of variable-rate long-term tax-exempt debt.
ComEd	$50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 D due March 1, 2020 (b)	Used to repay credit facility borrowings incurred to repurchase bonds. (c)
ComEd	$50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 E due March 21, 2021 (b)	Used to repay credit facility borrowings incurred to repurchase bonds. (c)
ComEd	$91 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 F due May 1, 2017 (b)	Used to repay credit facility borrowings incurred to repurchase bonds. (c)
PECO	$250 million of First and Refunding Mortgage Bonds at 5.00% due October 1, 2014	Used to refinance short-term debt and for other general corporate purposes.

(a) Repurchase required due to failed remarketing.
(b) Remarketed in May 2009 with letter of credit issued under credit facility.
(c) Repurchase required due to expiration of existing letter of credit.

Company	Issuances of long-term debt in 2008	Use of proceeds
ComEd	$50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 D due March 1, 2020 (a)	Used to refinance $50 million tax-exempt variable auction-rate pollution control bonds secured by First Mortgage Bonds Series 2003 C, due March 1, 2020.
ComEd	$50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 E due March 21, 2021 (a)	Used to refinance a portion of the outstanding tax-exempt variable auction-rate pollution control bonds secured by First Mortgage Bonds, Series 2003, 2003 B and 2003 D, due May 15, 2017, November 1, 2019 and January 15, 2014.
ComEd	$91 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 F due May 1, 2017 (a)	Used to refinance $91 million tax-exempt variable auction-rate pollution control bonds secured by First Mortgage Bonds Series 2005, due March 1, 2017.
ComEd	$450 million of First Mortgage 6.45% Bonds, Series 107, due January 15, 2038	Used to retire $295 million of First Mortgage Bonds, Series 99, to call and refinance $155 million of trust preferred securities and for other general corporate purposes.

Company	Issuances of long-term debt in 2008	Use of proceeds
ComEd	$700 million of First Mortgage 5.80% Bonds, Series 108, due March 15, 2018	Used to repay a portion of borrowings under ComEd's revolving credit facility, to provide for the retirement at scheduled maturity in May 2008 of $120 million of First Mortgage Bonds, Series 83 and for other general corporate purposes.
PECO	$150 million of First and Refunding Mortgage Bonds, 4.00% due December 1, 2012 [b]	Used to refinance First and Refunding Mortgage Bonds, variable rate due December 1, 2012.
PECO	$300 million of First and Refunding Mortgage Bonds, 5.60% due October 15, 2013	Used to refinance short-term debt.
PECO	$500 million of First and Refunding Mortgage Bonds, 5.35% due March 1, 2018	Used to refinance commercial paper and for other general corporate purposes.

(a) First Mortgage Bonds issued under the ComEd mortgage indenture to secure variable weekly-rate tax-exempt pollution control bonds that were issued to refinance variable auction-rate tax-exempt pollution control bonds.
(b) First and Refunding Mortgage Bonds issued under the PECO mortgage indenture to secure tax-exempt pollution control bonds and notes that were issued to refinance auction-rate tax-exempt pollution control bonds.

Company	Retirement of long-term debt in 2010
Exelon Corporate	$400 million of 4.45% 2005 Senior Notes due June 15, 2010
Generation	$1 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
Generation	$13 million of Montgomery County Series 1994 B Tax Exempt Bonds with variable interest rates due June 1, 2029
Generation	$17 million of Indiana County Series 2003 A Tax Exempt Bonds with variable interest rates due June 1, 2027
Generation	$19 million of York County Series 1993 A Tax Exempt Bonds with variable interest rates due August 1, 2016
Generation	$23 million of Salem County 1993 Series A Tax Exempt Bonds with variable interest rates due March 1, 2025
Generation	$24 million of Delaware County Series 1993 A Tax Exempt Bonds with variable interest rates due August 1, 2016
Generation	$34 million of Montgomery County Series 1996 A Tax Exempt Bonds with variable interest rates due March 1, 2034
Generation	$83 million of Montgomery County Series 1994 A Tax Exempt Bonds with variable interest rates due June 1, 2029
ComEd	$1 million of 4.75% sinking fund debentures due December 1, 2011
ComEd	$212 million of 4.74% First Mortgage Bonds due August 15, 2010
PECO	$806 million of 6.52% PETT Transition Bonds due September 1, 2010

Company	Retirement of long-term debt in 2009
Exelon Corporate	$500 million of 6.75% Senior Notes due May 1, 2011
Generation	$700 million of 6.95% Senior Notes due June 15, 2011
Generation	$46 million of Pollution Control Notes with variable interest rates, due December 1, 2042 [a]
Generation	$51 million of Pollution Control Notes with variable interest rates, due April 1, 2021
Generation	$39 million of Pollution Control Notes with variable interest rates, due April 1, 2021
Generation	$30 million of Pollution Control Notes with variable interest rates, due December 1, 2029
Generation	$92 million of Pollution Control Notes with variable interest rates, due October 1, 2030
Generation	$69 million of Pollution Control Notes with variable interest rates, due October 1, 2030
Generation	$14 million of Pollution Control Notes with variable interest rates, due October 1, 2034
Generation	$13 million of Pollution Control Notes with variable interest rates, due October 1, 2034
Generation	$10 million of 6.33% notes payable, due August 8, 2009
Generation	$1 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020

Company	Retirement of long-term debt in 2009
ComEd	$91 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 F, due March 1, 2017 [(b)]
ComEd	$50 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, due March 1, 2020 [(b)]
ComEd	$50 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 E, due May 21, 2021 [(b)]
ComEd	$16 million of 5.70% First Mortgage Bonds, Series 1994 B, due January 15, 2009
ComEd	$1 million of 4.625-4.75% sinking fund debentures, due at various dates
PECO	$319 million of 7.65% PETT Transition Bonds, due September 1, 2009
PECO	$390 million of 6.52% PETT Transition Bonds, due September 1, 2010

(a) Repurchased due to a failed remarketing and remarketed in February 2009.
(b) First Mortgage Bonds issued under the ComEd mortgage indenture to secure variable weekly-rate tax-exempt pollution controls bonds. Repurchased due to expiration of existing letter of credit and remarketed in May 2009.

Company	Retirement of long-term debt in 2008
Exelon Corporate	$21 million of 6.00-8.00% notes payable for investments in synthetic fuel-producing facilities due at various dates
Generation	$3 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
Generation	$10 million scheduled payments of 6.33% notes payable until August 8, 2009
ComEd	$2 million of 3.875-4.75% sinking fund debentures due at various dates
ComEd	$20 million of tax-exempt variable auction-rate First Mortgage Bonds, Series 2003 D, due January 15, 2014 [(a)]
ComEd	$40 million of tax-exempt variable auction-rate First Mortgage Bonds, Series 2003, due May 15, 2017 [(a)]
ComEd	$42 million of tax-exempt variable auction-rate First Mortgage Bonds, Series 2003 B, due November 1, 2019 [(a)]
ComEd	$50 million of tax-exempt variable auction-rate First Mortgage Bonds, Series 2003 C, due March 1, 2020 [(a)]
ComEd	$91 million of tax-exempt variable auction-rate First Mortgage Bonds, Series 2005, due March 1, 2017 [(a)]
ComEd	$100 million of tax-exempt variable auction-rate First Mortgage Bonds, Series 2002, due April 15, 2013 [(a)]
ComEd	$120 million of 8.00% First Mortgage Bonds, Series 83, due May 15, 2008
ComEd	$155 million of 8.50% Subordinated Debentures of ComEd Financing II, due January 15, 2027
ComEd	$274 million of 5.74% ComEd Transitional Funding Trust, due December 25, 2008
ComEd	$295 million of 3.70% First Mortgage Bonds, Series 99, due February 1, 2008
PECO	$33 million of 7.65% PETT Transition Bonds, due September 1, 2009
PECO	$154 million of First and Refunding Mortgage Bonds, variable rate due December 1, 2012 [(b)]
PECO	$207 million of 6.13% PETT Transition Bonds, due September 1, 2008
PECO	$369 million of 7.625% PETT Transition Bonds, due March 1, 2009
PECO	$450 million of 3.5% First and Refunding Mortgage Bonds, due May 1, 2008

(a) First Mortgage Bonds issued under the ComEd mortgage indenture to secure variable auction-rate tax-exempt pollution control bonds.
(b) First and Refunding Mortgage Bonds issued under the PECO mortgage indenture to secure tax-exempt pollution control bonds and notes that were issued to refinance auction-rate tax-exempt control bonds.

From time to time and as market conditions warrant, the Registrants may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt on their balance sheets.

Dividends. Cash dividend payments and distributions during 2010, 2009 and 2008 were as follows:

	2010	2009	2008
Exelon	$1,389	$1,385	$1,335
Generation	1,508	2,276	1,545
ComEd [(a)]	310	240	—
PECO	228	316	484

(a) During 2008, ComEd did not pay a dividend to manage cash flows and its capital structure.

On January 25, 2011, the Exelon Board of Directors declared a quarterly dividend of $0.525 per share on Exelon's common stock, which is payable on March 10, 2011 to shareholders of record at the end of the day on February 15, 2011.

Share Repurchases. During 2008, Exelon purchased $500 million of common stock under Exelon's accelerated share repurchase program, including the impact of the settlement of a forward contract indexed to Exelon's own common stock.

Short-Term Borrowings. Short-term borrowings incurred (repaid) during 2010, 2009 and 2008 were as follows:

	2010	2009	2008
ComEd	$(155)	$ 95	$(310)
PECO	—	(95)	(151)
Other [(a)]	—	(56)	56
Exelon	(155)	(56)	(405)

(a) Other primarily consists of corporate operations and BSC.

Retirement of Long-Term Debt to Financing Affiliates. Retirement of long-term debt to financing affiliates during 2010, 2009 and 2008 were as follows:

	2010	2009	2008
Exelon	$—	$709	$1,038
ComEd	—	—	429
PECO	—	709	609

Contributions from Parent/Member. Contributions from Parent/Member (Exelon) during 2010, 2009 and 2008 were as follows:

	2010	2009	2008
Generation	$ 62	$ 57	$ 86
ComEd	2	8	14
PECO [(a)]	223	347	320

(a) $180 million, $320 million and $284 million for the years ended December 31, 2010, 2009 and 2008, respectively, reflect payments received to reduce the receivable from parent, which was completely repaid as of December 31, 2010.

Other. Other significant financing activities for Exelon for 2010, 2009 and 2008 were as follows:

- Exelon received proceeds from employee stock plans of $48 million, $42 million and $130 million during 2010, 2009 and 2008, respectively.
- Exelon's other financing activities during 2010, 2009 and 2008 include $3 million, $5 million and $60 million, respectively, of excess tax benefits related to compensation cost recognized for stock options exercised.

Credit Matters

Market Conditions

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large diversified credit facilities. The credit facilities include $7.4 billion in aggregate total commitments of which $6.9 billion was available as of December 31, 2010, and of which no financial institution has more than 10% of the aggregate commitments for Exelon, Generation, ComEd. Generation also had additional letter of credit facilities that expired in the second quarter of 2010, which were used to enhance variable rate long-term tax-exempt debt totaling $213 million. Generation repurchased the $213 million of tax-exempt bonds during 2010 and has permanently extinguished $24 million of these tax-exempt bonds. Generation has the ability to remarket the remaining bonds whenever it determines it to be economically advantageous. Exelon, Generation, PECO and ComEd had access to the commercial paper market during 2010 to fund their short-term liquidity needs, when necessary. Due to an upgrade in ComEd's commercial paper rating in 2010 and improvements in the commercial paper market, ComEd has been able to rely on the commercial paper market as a source of liquidity. ComEd also utilized its credit facility in 2010 to fund its short-term liquidity needs and provide credit enhancement for $191 million of variable rate tax-exempt bonds. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels, and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A Risk Factors of Exelon's 2010 Form 10-K for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operations, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of December 31, 2010, it would have been required to provide incremental collateral of approximately $1,156 million, which is well within its current available credit facility capacities of approximately $4.6 billion. The $1,156 million includes $944 million of collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payable and receivables, net of the contractual right of offset under master netting agreements and $212 million of financial assurances that Generation would be required to provide NEIL related to annual retrospective premium obligations. If ComEd lost its investment grade credit rating as of December 31, 2010, it would have been required to provide incremental collateral of approximately $233 million, which is well within its current available credit facility capacity of approximately $804 million. If PECO lost its investment grade credit rating as of December 31, 2010, it would have been required to provide collateral of $5 million pursuant to PJM's credit policy and could have been required to provide collateral of approximately $68 million related to its natural gas procurement contracts, which are well within PECO's current available credit facility capacity of $573 million.

Exelon Credit Facilities

See Note 10 of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' credit facilities and short term borrowing activity.

Other Credit Matters

Capital Structure

At December 31, 2010, the capital structure of the Registrants consisted of the following:

	Exelon Consolidated	Generation	ComEd	PECO
Long-term debt	46%	34%	41%	40%
Long-term debt to affiliates (a)	2	—	2	3
Common equity	51	—	57	51
Member's equity	—	66	—	—
Preferred securities	—	—	—	2
Commercial paper and notes payable	1	—	—	4

(a) Includes approximately $390 million, $206 million and $184 million owed to unconsolidated affiliates of Exelon, ComEd and PECO, respectively, that qualify as special purpose entities under the applicable authoritative guidance. These special purpose entities were created for the sole purposes of issuing mandatorily redeemable trust preferred securities of ComEd and PECO. See Note 1 of the Combined Notes to Consolidated Financial Statements for additional information regarding the authoritative guidance for VIEs.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. As of January 10, 2006, ComEd voluntarily suspended its participation in the money pool. Generation, PECO, and BSC may participate in the intercompany money pool as lenders and borrowers, and Exelon may participate as a lender. Funding of, and borrowings from, the intercompany money pool are predicated on whether the contributions and borrowings result in economic benefits. Interest on borrowings is based on short-term market rates of interest or, if from an external source, specific borrowing rates. Maximum amounts contributed to and borrowed from the intercompany money pool by participant during 2010 are described in the following table in addition to the net contribution or borrowing as of December 31, 2010:

	Maximum Contributed	Maximum Borrowed	December 31, 2010 Contributed (Borrowed)
PECO	$ 31	$—	$—
BSC	—	67	(20)
Exelon Corporate	67	N/A	20

Shelf Registrations

The Registrants filed automatic shelf registration statements that are not required to specify the amount of securities to be offered thereon. As of December 31, 2010, the Registrants each had current shelf registration statements for the sale of unspecified amounts of securities that were effective with the SEC. The ability of each Registrant to sell securities off its shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations

The issuance by ComEd and PECO of long-term debt or equity securities requires the prior authorization of the ICC and PAPUC, respectively. ComEd and PECO normally obtain the required approvals on a periodic basis to cover their anticipated financing needs for a period of time or in connection with a specific financing. As of December 31, 2010, ComEd had $577 million in long-term debt refinancing authority from the ICC and $1.1 billion in new money long-term debt financing authority. After ComEd issued $600 million of First Mortgage Bonds, Series 110, on January 18, 2011, its new money long-term debt financing authority with the ICC was reduced to $520 million. As of December 31, 2010, PECO had $1.9 billion in long-term debt financing authority from the PAPUC.

FERC has financing jurisdiction over ComEd's and PECO's short-term financings and all of Generation's financings. As of December 31, 2010, ComEd and PECO had short-term financing authority from FERC that expires on December 31, 2011 of $2.5 billion and $1.5 billion, respectively. Generation currently has blanket financing authority that it received from FERC in connection with its market-based rate authority. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Exelon's ability to pay dividends on its common stock depends on the payment to it of dividends by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." In addition, under Illinois law, ComEd may not pay any dividend on its stock, unless, among other things, its earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless ComEd has specific authorization from the ICC. At December 31, 2010, Exelon had retained earnings of $9,304 million, including Generation's undistributed earnings of $2,633 million, ComEd's retained earnings of $331 million consisting of retained earnings appropriated for future dividends of $1,970 million partially offset by $1,639 million of unappropriated retained deficit, and PECO's retained earnings of $522 million. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Contractual Obligations and Off-Balance Sheet Arrangements

The following table summarizes Exelon's future estimated cash payments as of December 31, 2010 under existing contractual obligations, including payments due by period. See Note 18 of the Combined Notes to Consolidated Financial Statements for information regarding Exelon's commercial commitments, representing commitments potentially triggered by future events.

Exelon

		Payment due within				
	Total	2011	2012-2013	2014-2015	Due 2016 and beyond	All Other
Long-term debt (a)	$12,588	$ 597	$1,377	$1,827	$ 8,787	$—
Interest payments on long-term debt (b)	8,849	688	1,230	1,056	5,875	—
Liability and interest for uncertain tax positions (c)	204	—	—	—	—	204
Capital leases	36	2	6	7	21	—
Operating leases (d)	700	70	131	99	400	—
Purchase power obligations (e)	2,021	351	442	288	940	—
Fuel purchase agreements (f)	10,041	1,439	2,331	2,223	4,048	—
Electric supply procurement (f)	1,869	1,252	578	39	—	—
REC and AEC purchase commitments (f)	28	8	6	4	10	—
Long-term renewable energy and associated REC commitments (g)	1,692	—	106	150	1,436	—
Other purchase obligations (h)	738	366	314	53	5	—
City of Chicago agreement—2003 (i)	12	6	6	—	—	—
Spent nuclear fuel obligation	1,018	—	—	—	1,018	—
Pension minimum funding requirement (j)	1,412	807	243	330	32	—
Total contractual obligations	$41,208	$5,586	$6,770	$6,076	$22,572	$204

(a) Includes $390 million due after 2016 to ComEd and PECO financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2010 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2010. Includes estimated interest payments due to ComEd and PECO financing trusts.

(c) As of December 31, 2010, Exelon's liability for uncertain tax positions and related net interest payable were $204 million and $22 million, respectively. Exelon was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. Exelon has other unrecognized tax positions that were not recorded on the Consolidated Balance Sheet in accordance with authoritative guidance. See Note 11 of the Combined Notes to Consolidated Financial Statements for further information regarding unrecognized tax positions.

(d) Excludes PPAs and other capacity contracts that are accounted for as operating leases. These amounts are included within purchase power obligations. Includes estimated cash payments for service fees related to PECO's meter reading operating lease.

(e) Purchase power obligations include PPAs and other capacity contracts that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2010. Expected payments include certain capacity charges that are contingent on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. These obligations do not include ComEd's SFCs as these contracts do not require purchases of fixed or minimum quantities. See Notes 2 and 18 of the Combined Notes to Consolidated Financial Statements.

(f) Represents commitments to purchase natural gas and related transportation and storage capacity and services, procure electric supply, and purchase AECs. See Note 18 of the Combined Notes to Consolidated Financial Statements for electric and gas purchase commitments.

(g) On December 17, 2010, ComEd entered into 20-year contracts with several unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. See Note 2 of Combined Notes to Consolidated Financial Statements for additional information.

(h) Commitments for services, materials and information technology.

(i) In 2003, ComEd entered separate agreements with the City of Chicago and with Midwest Generation. Under the terms of the agreements, ComEd will pay the City of Chicago $60 million over ten years to be relieved of a requirement, originally transferred to Midwest Generation upon the sale of ComEd's fossil stations in 1999, to build a 500-MW generation facility.

(j) These amounts represent Exelon's estimated minimum pension contributions to its qualified plans required under ERISA and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2016 are currently not reliably estimable. Exelon made an incremental contribution in January 2011, which was contemplated in determining the future years' minimum contributions, and may choose to make further additional contributions in future years. See Note 13 of the Combined Notes to Consolidated Financial Statements for further information regarding the January 2011 pension contribution.

See Note 18 of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' other commitments potentially triggered by future events.

For additional information regarding:

- commercial paper, see Note 10 of the Combined Notes to Consolidated Financial Statements.
- long-term debt, see Note 10 of the Combined Notes to Consolidated Financial Statements.
- liabilities related to uncertain tax positions, see Note 11 of the Combined Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 10 of the Combined Notes to Consolidated Financial Statements.
- operating leases, energy commitments, fuel purchase agreements, construction commitments and rate relief commitments, see Note 18 of the Combined Notes to Consolidated Financial Statements.
- the nuclear decommissioning and SNF obligations, see Notes 12 and 18 of the Combined Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 2 of the Combined Notes to Consolidated Financial Statements.
- variable interest entities, see Note 1 of the Combined Notes to Consolidated Financial Statements.
- nuclear insurance, see Note 18 of the Combined Notes to Consolidated Financial Statements.
- new accounting pronouncements, see Note 1 of the Combined Notes to Consolidated Financial Statements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief financial officer, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Exelon Board of Directors on the scope of the risk management activities.

Commodity Price Risk (Exelon, Generation, ComEd and PECO)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the purchase and sale of electricity, fossil fuel, and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including ComEd's and PECO's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into physical contracts as well as financial derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges, including the ComEd financial swap contract, will occur during 2011 through 2013. Generation's energy contracts are accounted for under the accounting guidance for derivatives as further discussed in Note 9 of the Combined Notes to Consolidated Financial Statements.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Generation hedges commodity risk on a ratable basis over the three years leading to the spot market. As of December 31, 2010, the percentage of expected generation hedged was 90%-93%, 67%-70% and 32%-35% for 2011, 2012 and 2013, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include cash flow hedges, other derivatives and certain non-derivative contracts including sales to ComEd and PECO to serve their retail load.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's non-trading portfolio associated with a $5 reduction in the annual average Ni-Hub and PJM-West around-the-clock energy price based on December 31, 2010 market conditions and hedged position would be a decrease in pre-tax net income of approximately $33 million, $275 million and $531 million, respectively, for 2011, 2012 and 2013. Power prices sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into purely to profit from market price changes as opposed to hedging an exposure and is subject to limits established by Exelon's RMC. The trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 3,625 GWh, 7,578 GWh and 8,891 GWh for the years ended December 31, 2010, 2009, and 2008 respectively, are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall revenue from energy marketing activities. Trading portfolio activity for the year ended December 31, 2010 resulted in pre-tax gains of $27 million due to net mark-to-market gains of $2 million and realized gains of $25 million. Generation uses a 95% confidence interval, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $140,000 of exposure over the last 18 months. Because of the relative size of the proprietary trading portfolio in comparison to Generation's total gross margin from continuing operations for the year ended December 31, 2010 of $6,562 million, Generation has not segregated proprietary trading activity in the following tables.

Fuel Procurement. Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained primarily through long-term contracts for uranium concentrates, and long-term contracts for conversion services, enrichment services and fuel fabrication services. The supply markets for coal, natural gas, uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 57% of Generation's uranium concentrate requirements from 2011 through 2015 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information regarding uranium and coal supply agreement matters.

ComEd

The financial swap contract between Generation and ComEd was deemed prudent by the Illinois Settlement Legislation, thereby ensuring that ComEd will be entitled to receive full cost recovery in rates. The change in fair value each period is recorded by ComEd with an offset to a regulatory asset or liability.

The contracts that ComEd has entered into as part of the initial ComEd auction and the RFP contracts are deemed to be derivatives that qualify for the normal purchases and normal sales exception under derivative accounting guidance. ComEd does not enter into derivatives for speculative or trading purposes.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. Delivery under these contracts begins in June 2012. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding derivatives.

PECO

Prior to January 1, 2011, PECO had transferred substantially all of its commodity price risk related to its procurement of electric supply to Generation through a PPA that expired on December 31, 2010. The PPA was not considered a derivative under current authoritative derivative guidance. Pursuant to PECO's PAPUC-approved DSP Program, PECO began to procure electric supply for default service customers in June 2009 for the post-transition period beginning on January 1, 2011 through block contracts and full requirements contracts. PECO's full requirements contracts and block contracts that are considered derivatives qualify for the normal purchases and normal sales exception under current authoritative derivative guidance. Under the DSP Program, PECO is permitted to recover its electricity procurement costs from retail customers without mark-up.

PECO has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales exception, to hedge its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities. The following detailed presentation of Exelon's, Generation's, ComEd's and PECO's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's, ComEd's and PECO's mark-to-market net asset or liability balance sheet position from January 1, 2009 to December 31, 2010. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings as well as the settlements from OCI to earnings and changes in fair value for the hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts. For additional information on the cash flow hedge gains and losses included within accumulated OCI and the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2010 and December 31, 2009 refer to Note 9 of the Combined Notes to Consolidated Financial Statements.

	Generation	ComEd	PECO	Intercompany Eliminations [g]	Exelon
Total mark-to-market energy contract net assets (liabilities) at January 1, 2009 [a]	$ 1,363	$(456)	$—	$ —	$ 907
Total change in fair value during 2009 of contracts recorded in result of operations	137	—	—	—	137
Reclassification to realized at settlement of contracts recorded in results of operations	(24)	—	—	—	(24)
Ineffective portion recognized in income [b]	(15)	—	—	—	(15)
Reclassification to realized at settlement from accumulated OCI [c]	(1,559)	—	—	267	(1,292)
Effective portion of changes in fair value—recorded in OCI [d]	2,052	—	—	(784)	1,268
Changes in fair value—energy derivatives [e]	—	(515)	(4)	517	(2)
Changes in collateral	(194)	—	—	—	(194)
Changes in net option premium paid/(received)	40	—	—	—	40
Other income statement reclassifications [f]	(46)	—	—	—	(46)
Other balance sheet reclassifications	15	—	—	—	15
Total mark-to-market energy contract net assets (liabilities) at December 31, 2009 [a]	$ 1,769	$(971)	$ (4)	$ —	$ 794
Total change in fair value during 2010 of contracts recorded in result of operations	415	—	—	—	415
Reclassification to realized at settlement of contracts recorded in results of operations	(328)	—	—	—	(328)
Ineffective portion recognized in income [b]	1	—	—	—	1
Reclassification to realized at settlement from accumulated OCI [c]	(1,125)	—	—	371	(754)
Effective portion of changes in fair value—recorded in OCI [d]	883	—	—	(378)	505
Changes in fair value—energy derivatives [e]	—	—	(5)	7	2
Changes in collateral	(4)	—	—	—	(4)
Changes in net option premium paid/(received)	124	—	—	—	124
Other income statement reclassifications [f]	73	—	—	—	73
Other balance sheet reclassifications	(5)	—	—	—	(5)
Total mark-to-market energy contract net assets (liabilities) at December 31, 2010 [a]	$ 1,803	$(971)	$ (9)	$ —	$ 823

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) For Generation, includes $1 million and $15 million of changes in cash flow hedge ineffectiveness, of which none was related to Generation's financial swap contract with ComEd or Generation's block contracts with PECO for the years ended December 31, 2010 and 2009, respectively.
(c) For Generation, includes $371 million and $267 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the years ended December 31, 2010 and 2009, respectively.
(d) For Generation, includes $375 million and $782 million of gains related to the changes in fair value of the five-year financial swap with ComEd for the years ended December 31, 2010 and 2009, respectively, and $3 million and $2 million of gains related to the changes in fair value of the block contracts with PECO for the years ended December 31, 2010 and 2009, respectively. The PECO block contracts were designated as normal as of May 31, 2010. As such, there were no effective changes in fair value of PECO's block contracts for the remainder of 2010 as the mark-to-market balances previously recorded will be amortized over the term of the contract.

(e) For ComEd and PECO, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2010 and 2009, ComEd recorded a regulatory asset of $971 million, related to its mark-to-market derivative liabilities. During 2010 and 2009, this includes $375 million and $782 million of increases related to changes in fair value, respectively, and $371 million and $267 million of decreases, respectively, for reclassifications from regulatory asset to recognize cost in purchased power expense due to settlements of ComEd's five-year financial swap with Generation. During 2010 ComEd also recorded a $4 million increase in fair value associated with floating-to-fixed energy swap contracts with unaffiliated suppliers. As of December 31, 2010 and 2009, PECO recorded a regulatory asset of $9 million and $4 million, respectively, related to its mark-to-market derivative liabilities. During December 31, 2010 and 2009, PECO's change in fair value includes $3 million and $2 million related to changes in fair value, respectively, associated with the fair value of PECO's block contracts with Generation. PECO's block contracts were designated as normal sales as of May 31, 2010. As such, there were no changes in fair value of PECO's block contracts with Generation for the remainder of 2010 and the mark-to-market balances previously recorded will be amortized over the term of the contract beginning January 2011.

(f) Includes $73 million and $46 million of amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of the underlying transactions for the years ended December 31, 2010 and 2009, respectively.

(g) Amounts related to the five-year financial swap between Generation and ComEd and the block contracts between Generation and PECO are eliminated in consolidation.

Fair Values

The following tables present maturity and source of fair value of the Registrants mark-to-market energy contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities). Second, the tables show the maturity, by year, of the Registrants' energy contract net assets (liabilities), giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 8 of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2011	2012	2013	2014	2015	2016 and Beyond	Total Fair Value
Normal Operations, qualifying cash flow hedge contracts (a)(c):							
Prices provided by external sources	$311	$ 98	$ 33	$ 3	$—	$—	$445
Prices based on model or other valuation methods	4	3	3	1	—	—	11
Total	$315	$101	$ 36	$ 4	$—	$—	$456
Normal Operations, other derivative contracts (b)(c):							
Actively quoted prices	$ (1)	$ (1)	$—	$—	$—	$—	$ (2)
Prices provided by external sources	111	125	60	34	—	—	330
Prices based on model or other valuation methods (d)	25	(11)	(1)	(6)	(7)	39	39
Total	$135	$113	$ 59	$ 28	$ (7)	$ 39	$367

(a) Mark-to-market gains and losses on contracts that qualify as cash flow hedges are recorded in OCI.
(b) Mark-to-market gains and losses on other non-trading hedge and trading derivative contracts that do not qualify as cash flow hedges are recorded in results of operations.
(c) Amounts are shown net of collateral paid to and received from counterparties and offset against mark-to-market assets and liabilities of $951 million at December 31, 2010.
(d) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers. The floating-to-fixed energy swap contracts are recorded in Other deferred debits and other assets on ComEd's Consolidated Balance Sheets.

Generation

	Maturities Within						
	2011	**2012**	**2013**	**2014**	**2015**	**2016 and Beyond**	**Total Fair Value**
Normal Operations, qualifying cash flow hedge contracts [(a)(c)]:							
Prices provided by external sources	$311	$ 98	$ 33	$ 3	$—	$—	$ 445
Prices based on model or other valuation methods	459	392	139	1	—	—	991
Total	$770	$490	$172	$ 4	$—	$—	$1,436
Normal Operations, other derivative contracts [(b)(c)]:							
Actively quoted prices	$ (1)	$ (1)	$—	$—	$—	$—	$ (2)
Prices provided by external sources	111	125	60	34	—	—	330
Prices based on model or other valuation methods	29	(4)	10	3	1	—	39
Total	$139	$120	$ 70	$ 37	$ 1	$—	$ 367

(a) Mark-to-market gains and losses on contracts that qualify as cash flow hedges are recorded in OCI. Amounts include a $975 million gain associated with the five-year financial swap with ComEd and $5 million gain related to the fair value of the PECO block contracts.

(b) Mark-to-market gains and losses on other non-trading hedge and trading derivative contracts that do not qualify as cash flow hedges are recorded in results of operations.

(c) Amounts are shown net of collateral paid to and received from counterparties and offset against mark-to-market assets and liabilities of $951 million at December 31, 2010.

ComEd

	Maturities Within						
	2011	**2012**	**2013**	**2014**	**2015**	**2016 and Beyond**	**Fair Value**
Prices based on model or other valuation methods [(a)]	$(450)	$(396)	$(147)	$(9)	$(8)	$39	$(971)

(a) Represents ComEd's net assets (liabilities) associated with the five-year financial swap with Generation and the floating-to-fixed energy swap contracts with unaffiliated suppliers. The floating-to-fixed energy swap contracts are recorded in Other deferred debits and other assets on ComEd's Consolidated Balance Sheets.

PECO

	Maturities Within						
	2011	**2012**	**2013**	**2014**	**2015**	**2016 and Beyond**	**Total Fair Value**
Prices based on model or other valuation methods [(a)]	$(9)	$—	$—	$—	$—	$—	$(9)

(a) Represents PECO's liabilities associated with its block contracts executed under its DSP Program. Includes $5 million related to the fair value of PECO's block contracts with Generation.

Credit Risk, Collateral, and Contingent Related Features (Exelon, Generation, ComEd and PECO)

The Registrants are exposed to credit-related losses in the event of non-performance by counterparties with whom they enter into derivative instruments. The credit exposure of derivative contracts, before collateral and netting, is represented by the fair value of contracts at the reporting date. See Note 9 of the Combined Notes to Consolidated Financial Statements for a detail discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2010. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs and NYMEX and ICE commodity exchanges, which are discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd and PECO of $58 million and $248 million, respectively. See Note 21 of the Combined Notes to Consolidated Financial Statements for further information.

Rating as of December 31, 2010	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$1,495	$563	$932	1	$102
Non-investment grade	9	3	6	—	—
No external ratings					
Internally rated—investment grade	42	5	37	—	—
Internally rated—non-investment grade	1	1	—	—	—
Total	$1,547	$572	$975	1	$102

Rating as of December 31, 2010	Maturity of Credit Risk Exposure: Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$1,238	$203	$ 54	$1,495
Non-investment grade	9	—	—	9
No external ratings				
Internally rated—investment grade	29	11	2	42
Internally rated—non-investment grade	1	—	—	1
Total	$1,277	$214	$ 56	$1,547

Net Credit Exposure by Type of Counterparty	As of December 31, 2010
Financial institutions	$280
Investor-owned utilities, marketers and power producers	515
Other	180
Total	$975

ComEd

Credit risk for ComEd is managed by credit and collection policies, which are consistent with state regulatory requirements. ComEd is currently obligated to provide service to all electric customers within its franchised territory. ComEd records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. ComEd will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. In February 2010, the ICC approved ComEd's tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense. The Illinois Settlement Legislation prohibits utilities, including ComEd, from terminating electric service to a residential electric space heat customer due to nonpayment between December 1 of any year through March 1 of the following year. ComEd's ability to disconnect non space-heating residential customers is also impacted by certain weather restrictions, at any time of year, under the Illinois Public Utilities Act. ComEd will monitor the impact of its disconnection practices and will make any necessary adjustments to the provision for uncollectible accounts. ComEd did not have any customers representing over 10% of its revenues as of December 31, 2010. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information regarding ComEd's recently approved tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion. The unsecured credit used by the suppliers represents ComEd's credit exposure. As of December 31, 2010, ComEd's credit exposure to energy suppliers was immaterial.

PECO

Credit risk for PECO is managed by credit and collection policies, which are consistent with state regulatory requirements. PECO is currently obligated to provide service to all retail electric customers within its franchised territory. PECO records a provision for uncollectible accounts, primarily based upon historical experience, to provide for the potential loss from nonpayment by these customers. In accordance with PAPUC regulations, after November 30 and before April 1, an electric distribution utility or natural gas distribution utility shall not terminate service to customers with household incomes at or below 250% of the Federal poverty level. PECO's provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in PAPUC regulations. PECO did not have any customers representing over 10% of its revenues as of December 31, 2010.

PECO's supplier master agreements that govern the terms of its DSP Program contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from S&P, Fitch or Moody's and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. If the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2010, PECO's credit exposure to suppliers under its electric procurement contracts was immaterial.

PECO does not obtain collateral from suppliers under its natural gas supply and management agreements. As of December 31, 2010, PECO had credit exposure of $10 million under its natural gas supply and management contracts.

Collateral (Generation, ComEd and PECO)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the purchase and sale of electricity, fossil fuel and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, the obligation to supply the collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. If Generation can reasonably claim that it is willing and financially able to perform its obligations, it may be possible to successfully argue that no collateral should be posted or that only an amount equal to two or three months of future payments should be sufficient. See Note 9 of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation sells output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Exelon depends on access to bank credit facilities which serve as liquidity sources to fund collateral requirements. Since the banking industry issues started to surface in mid-2007, credit markets have tightened. Exelon will be required to renew most of its credit facilities in the 2011-2012 timeframe. The cost and availability to renew may be substantially different than when Exelon originally negotiated the existing liquidity facilities.

As of December 31, 2010, Generation was holding $955 million of cash collateral deposits received from counterparties and Generation had sent $3 million of cash collateral to counterparties. Net cash collateral deposits received of $951 million were offset against mark-to-market assets and liabilities. As of December 31, 2010, $1 million of cash collateral received was not offset against net derivative positions because it was not associated with energy-related derivatives. As of December 31, 2009, Generation was holding $965 million of cash collateral deposits received from counterparties and Generation had sent $12 million of cash collateral to counterparties. Net cash collateral deposits received of $947 million were offset mark-to-market assets and liabilities. As of December 31, 2009, $6 million of cash collateral received was not offset against net mark-to-market assets and liabilities. See Note 18 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of December 31, 2010, ComEd did not hold any cash or letters of credit for the purpose of collateral from any of the suppliers in association with energy procurement contracts and held approximately $20 million in the form of cash and letters of credit for both annual and long-term renewable energy contracts. See Notes 2 and 9 of the Combined Notes to Consolidated Financial Statements for further information.

PECO

As of December 31, 2010, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 9 of the Combined Notes to Consolidated Financial Statements for further information.

RTOs and ISOs (Generation, ComEd and PECO)

Generation, ComEd and PECO participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, New York ISO, MISO, Southwest Power Pool, Inc. and the Electric Reliability Council of Texas. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may under certain circumstances require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Generation)

Generation enters into commodity transactions on NYMEX and ICE. The NYMEX and ICE clearinghouse act as the counterparty to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX and ICE are significantly collateralized and have limited counterparty credit risk.

Long-Term Leases (Exelon)

Exelon's consolidated balance sheets, as of December 31, 2010, included a $629 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of approximately $1.5 billion, less unearned income of $863 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms which are set at prices above the then expected fair market value of the plants. If the lessees do not exercise the fixed purchase options the lessees return the leasehold interests to Exelon and Exelon has the ability to require the lessees to arrange a service contract with a third party for a period following the lease term. In any event, Exelon is subject to residual value risk to the extent the fair value of the assets are less than the residual value. This risk is mitigated by the fair value of the fixed payments under the service contract. The term of the service contract, however, is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures including letters of credit, surety bonds and credit swaps. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Since 2008, the entity providing the credit enhancement for one of the lessees did not meet the credit rating requirements of the lease. Consequently, Exelon has indefinitely extended a waiver and reduction of the rating requirement, which Exelon may terminate by giving 90 days notice to the lessee. Exelon monitors the continuing credit quality of the credit enhancement party.

Exelon performed annual assessments as of July 31, 2010 and 2009 of the estimated fair value of long-term lease investments and concluded that the estimated fair values at the end of the lease terms exceeded the residual values established at the lease dates and recorded as investments on Exelon's balance sheet. Through December 31, 2010, no events have occurred or circumstances have changed that would require any formal reassessment subsequent to the July 2010 review.

Interest-Rate Risk (Exelon, Generation and ComEd)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest-rate exposure. The Registrants may also use interest rate swaps when deemed appropriate to adjust exposure based upon market conditions. Additionally, the Registrants may use forward-starting interest rate swaps and treasury rate locks to lock in interest-rate levels in anticipation of future financings. These strategies are employed to achieve a lower cost of capital. At December 31, 2010, Exelon had $100 million of notional amounts of fair value hedges outstanding. A hypothetical 10% increase in the interest rates associated with variable-rate debt would result in less than a $1 million decrease in Exelon's, Generation's and ComEd's pre-tax earnings for the year ended December 31, 2010. This calculation holds all other variables constant and assumes only the discussed changes in interest rates.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of December 31, 2010, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $410 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See Management's Discussion and Analysis of Financial Condition and Results of Operations, for further discussion of equity price risk as a result of the current capital and credit market conditions.

CERTIFICATIONS

The CEO of Exelon has made the required annual certifications for 2010 to the New York Stock Exchange and the Philadelphia Stock Exchange that Exelon is in compliance with the listing standards of those exchanges. The CEO and CFO have filed with the SEC all required certifications under section 302 of the Sarbanes-Oxley Act of 2002. These certifications are filed as Exhibits 31-1 and 31-2 to Exelon's 2010 Form 10-K.

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting. Exelon's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2010. In making this assessment, management used the criteria in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2010, Exelon's internal control over financial reporting was effective.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on the next page of this Financial Information supplement.

February 10, 2011

Report of Independent Registered Public Accounting Firm

To The Shareholders and the Board of Directors of Exelon Corporation:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations and comprehensive income, shareholders' equity and cash flows present fairly, in all material respects, the financial position of Exelon Corporation and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP
Chicago, Illinois
February 10, 2011

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	For the Years Ended December 31, 2010	2009	2008
Operating revenues	$18,644	$17,318	$18,859
Operating expenses			
Purchased power	4,425	3,215	4,270
Fuel	2,010	2,066	2,312
Operating and maintenance	4,453	4,612	4,538
Operating and maintenance for regulatory required programs	147	63	28
Depreciation and amortization	2,075	1,834	1,634
Taxes other than income	808	778	778
Total operating expenses	13,918	12,568	13,560
Operating income	4,726	4,750	5,299
Other income and deductions			
Interest expense, net	(792)	(654)	(699)
Interest expense to affiliates, net	(25)	(77)	(133)
Loss in equity method investments	—	(27)	(26)
Other, net	312	427	(407)
Total other income and deductions	(505)	(331)	(1,265)
Income from continuing operations before income taxes	4,221	4,419	4,034
Income taxes	1,658	1,712	1,317
Income from continuing operations	2,563	2,707	2,717
Discontinued operations			
Loss from discontinued operations, net of taxes of $0, $0 and $1, respectively	—	—	(1)
Gain on disposal of discontinued operations, net of taxes of $0, $0 and $14, respectively	—	—	21
Income from discontinued operations, net	—	—	20
Net income	2,563	2,707	2,737
Other comprehensive income (loss)			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic costs, net of taxes of $(7), $(6) and $(6), respectively	(11)	(13)	(9)
Actuarial loss reclassified to periodic cost, net of taxes of $79, $74 and $52, respectively	114	93	60
Transition obligation reclassified to periodic cost, net of taxes of $2, $2 and $2, respectively	3	3	3
Pension and non-pension postretirement benefit plan valuation adjustment, net of taxes of $(188), $47 and $(959), respectively	(288)	86	(1,459)
Change in unrealized gain (loss) on cash flow hedges, net of taxes of $(107), $(2) and $563, respectively	(151)	(12)	855
Change in unrealized gain (loss) on marketable securities, net of taxes of $0, $3 and $(6), respectively	(1)	5	(7)
Other comprehensive income (loss)	(334)	162	(557)
Comprehensive income	$ 2,229	$ 2,869	$ 2,180
Average shares of common stock outstanding:			
Basic	661	659	658
Diluted	663	662	662
Earnings per average common share—basic:			
Income from continuing operations	$ 3.88	$ 4.10	$ 4.13
Income from discontinued operations	—	—	0.03
Net income	$ 3.88	$ 4.10	$ 4.16
Earnings per average common share—diluted:			
Income from continuing operations	$ 3.87	$ 4.09	$ 4.10
Income from discontinued operations	—	—	0.03
Net income	$ 3.87	$ 4.09	$ 4.13
Dividends per common share	$ 2.10	$ 2.10	$ 2.03

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	2010	2009	2008
	For the Years Ended December 31,		
Cash flows from operating activities			
Net income	$ 2,563	$ 2,707	$ 2,737
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel amortization	2,943	2,601	2,308
Impairment of long-lived assets	—	223	—
Deferred income taxes and amortization of investment tax credits	981	756	374
Net fair value changes related to derivatives	(88)	(95)	(515)
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(105)	(207)	363
Other non-cash operating activities	609	652	870
Changes in assets and liabilities:			
Accounts receivable	(232)	234	67
Inventories	(62)	51	(109)
Accounts payable, accrued expenses and other current liabilities	472	(254)	(44)
Option premiums paid, net	(124)	(40)	(124)
Counterparty collateral received (posted), net	(155)	196	1,027
Income taxes	(543)	(29)	(38)
Pension and non-pension postretirement benefit contributions	(959)	(588)	(230)
Other assets and liabilities	(56)	(113)	(135)
Net cash flows provided by operating activities	5,244	6,094	6,551
Cash flows from investing activities			
Capital expenditures	(3,326)	(3,273)	(3,117)
Proceeds from nuclear decommissioning trust fund sales	3,764	4,292	10,657
Investment in nuclear decommissioning trust funds	(3,907)	(4,531)	(10,942)
Acquisition of Exelon Wind	(893)	—	—
Proceeds from sales of investments	28	41	—
Purchases of investments	(22)	(28)	—
Change in restricted cash	423	35	29
Other investing activities	39	6	(5)
Net cash flows used in investing activities	(3,894)	(3,458)	(3,378)
Cash flows from financing activities			
Changes in short-term debt	(155)	(56)	(405)
Issuance of long-term debt	1,398	1,987	2,265
Retirement of long-term debt	(828)	(1,773)	(1,398)
Retirement of long-term debt of variable interest entity	(806)	—	—
Retirement of long-term debt to financing affiliates	—	(709)	(1,038)
Dividends paid on common stock	(1,389)	(1,385)	(1,335)
Proceeds from employee stock plans	48	42	130
Purchase of treasury stock	—	—	(436)
Purchase of forward contract in relation to certain treasury stock	—	—	(64)
Other financing activities	(16)	(3)	68
Net cash flows used in financing activities	(1,748)	(1,897)	(2,213)
Increase (decrease) in cash and cash equivalents	(398)	739	960
Cash and cash equivalents at beginning of period	2,010	1,271	311
Cash and cash equivalents at end of period	$ 1,612	$ 2,010	$ 1,271

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2010	December 31, 2009
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,612	$ 2,010
Restricted cash and investments	30	40
Accounts receivable, net		
Customer ($346 gross accounts receivable pledged as collateral as of December 31, 2010)	1,932	1,563
Other	1,196	486
Mark-to-market derivative assets	487	376
Inventories, net		
Fossil fuel	216	198
Materials and supplies	590	559
Other	335	209
Total current assets	6,398	5,441
Property, plant and equipment, net	29,941	27,341
Deferred debits and other assets		
Regulatory assets	4,140	4,872
Nuclear decommissioning trust funds	6,408	6,669
Investments	717	704
Investments in affiliates	15	20
Goodwill	2,625	2,625
Mark-to-market derivative assets	409	649
Pledged assets for Zion Station decommissioning	824	—
Other	763	859
Total deferred debits and other assets	15,901	16,398
Total assets	$52,240	$49,180

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2010	December 31, 2009
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 155
Short-term notes payable—accounts receivable agreement	225	—
Long-term debt due within one year	599	639
Long-term debt to PECO Energy Transition Trust due within one year	—	415
Accounts payable	1,373	1,345
Mark-to-market derivative liabilities	38	198
Accrued expenses	1,040	923
Deferred income taxes	85	152
Other	880	411
Total current liabilities	4,240	4,238
Long-term debt	11,614	10,995
Long-term debt to other financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	6,621	5,750
Asset retirement obligations	3,494	3,434
Pension obligations	3,658	3,625
Non-pension postretirement benefit obligations	2,218	2,180
Spent nuclear fuel obligation	1,018	1,017
Regulatory liabilities	3,555	3,492
Mark-to-market derivative liabilities	21	23
Payable for Zion Station decommissioning	659	—
Other	1,102	1,309
Total deferred credits and other liabilities	22,346	20,830
Total liabilities	38,590	36,453
Commitments and contingencies		
Preferred securities of subsidiary	87	87
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 662 and 660 shares outstanding at December 31, 2010 and December 31, 2009, respectively)	9,006	8,923
Treasury stock, at cost (35 shares held at December 31, 2010 and December 31, 2009, respectively)	(2,327)	(2,328)
Retained earnings	9,304	8,134
Accumulated other comprehensive loss, net	(2,423)	(2,089)
Total shareholders' equity	13,560	12,640
Noncontrolling interest	3	—
Total equity	13,563	12,640
Total liabilities and shareholders' equity	$52,240	$49,180

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total Shareholders' Equity
Balance, December 31, 2007	689,183	$8,579	$(1,838)	$ 4,930	$(1,534)	$—	$10,137
Net income	—	—	—	2,737	—	—	2,737
Long-term incentive plan activity	3,452	217	—	—	—	—	217
Employee stock purchase plan issuances	318	19	—	—	—	—	19
Common stock purchases	—	1	(500)	—	—	—	(499)
Common stock dividends	—	—	—	(1,007)	—	—	(1,007)
Adoption of the fair value option for financial assets and liabilities, net of income taxes of $286	—	—	—	160	(160)	—	—
Other comprehensive loss, net of income taxes of $(290)	—	—	—	—	(557)	—	(557)
Balance, December 31, 2008	692,953	$8,816	$(2,338)	$ 6,820	$(2,251)	$—	$11,047
Net income	—	—	—	2,707	—	—	2,707
Long-term incentive plan activity	1,088	85	10	(5)	—	—	90
Employee stock purchase plan issuances	524	22	—	—	—	—	22
Common stock dividends	—	—	—	(1,388)	—	—	(1,388)
Other comprehensive income, net of income taxes of $119	—	—	—	—	162	—	162
Balance, December 31, 2009	694,565	$8,923	$(2,328)	$ 8,134	$(2,089)	$—	$12,640
Net income	—	—	—	2,563	—	—	2,563
Long-term incentive plan activity	1,380	60	1	(1)	—	—	60
Employee stock purchase plan issuances	644	23	—	—	—	—	23
Common stock dividends	—	—	—	(1,392)	—	—	(1,392)
Acquisition of Exelon Wind	—	—	—	—	—	3	3
Other comprehensive loss, net of income taxes of $(221)	—	—	—	—	(334)	—	(334)
Balance, December 31, 2010	696,589	$9,006	$(2,327)	$ 9,304	$(2,423)	$ 3	$13,563

See the Combined Notes to Consolidated Financial Statements

1. Significant Accounting Policies

Description of Business

Exelon is a utility services holding company engaged, through its subsidiaries, in the generation and energy delivery businesses discussed below. The generation business consists of the electric generating facilities, the wholesale energy marketing operations and competitive retail supply operations of Generation. The energy delivery businesses include the purchase and regulated retail sale of electricity and the provision of transmission and distribution services by ComEd in northern Illinois, including the City of Chicago, and by PECO in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services by PECO in the Pennsylvania counties surrounding the City of Philadelphia.

Basis of Presentation

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology and supply management services. The costs of BSC, including support services, are directly charged or allocated to the applicable subsidiaries using a cost-causative allocation method. Corporate governance type costs that cannot be directly assigned are allocated based on a Modified Massachusetts formula, which is a method that utilizes a combination of gross revenues, total assets and direct labor costs for the allocation base. The results of Exelon's corporate operations are presented as "Other" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

Exelon owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for ComEd, of which Exelon owns more than 99%, and PECO, of which Exelon owns 100% of the common stock but none of PECO's preferred securities. Exelon has reflected the third-party interests in ComEd, which totaled less than $1 million at December 31, 2010 and December 31, 2009, as equity and PECO's preferred securities as preferred securities of subsidiaries in its consolidated financial statements.

Generation owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for Exelon SHC, Inc., of which Generation owns 99% and the remaining 1% is indirectly owned by Exelon, which is eliminated in Exelon's consolidated financial statements; and certain Exelon Wind projects, of which Generation holds a majority interest ranging from 94% to 99%, and which is included in Noncontrolling interest on Exelon's and Generation's Consolidated Balance Sheets.

Exelon's consolidated financial statements include the accounts of entities in which Exelon has a controlling financial interest, other than certain financing trusts of ComEd and PECO, and Generation's and PECO's proportionate interests in jointly owned electric utility property, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% or the results of a model that identifies Exelon or one of its subsidiaries as the primary beneficiary of a VIE. Investments and joint ventures in which Exelon does not have a controlling financial interest and certain financing trusts of ComEd and PECO are accounted for under the equity or cost method of accounting.

Each of Generation's, ComEd's and PECO's consolidated financial statements includes the accounts of their subsidiaries. All intercompany transactions have been eliminated.

Certain prior year amounts in Exelon's, Generation's and ComEd's Consolidated Statements of Cash Flows and in Exelon's, ComEd's and PECO's Consolidated Balance Sheets have been reclassified between line items for comparative purposes. The reclassifications did not affect net income or cash flows from operating activities of the Registrants. See Note 19—Supplemental Financial Information for further discussion of the reclassifications to Exelon's and Generation's Consolidated Statements of Cash Flows.

The Registrants performed an evaluation of subsequent events for the accompanying financial statements and notes included in Financial Statements and Supplementary Data of this Financial Information supplement through February 10, 2011, the date this Report was issued, to determine whether the circumstances warranted recognition and disclosure of those events or transactions in the financial statements as of December 31, 2010.

Use of Estimates

The preparation of financial statements of each of the Registrants in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Areas in which significant estimates have been made include, but are not limited to, the accounting for nuclear decommissioning costs and other AROs, pension and other postretirement benefits, inventory reserves, allowance for uncollectible accounts, goodwill and asset impairments, derivative instruments, fixed asset depreciation, environmental costs, taxes and unbilled energy revenues. Actual results could differ from those estimates.

Accounting for the Effects of Regulation

Exelon, ComEd and PECO account for their regulated operations in accordance with accounting policies prescribed by the regulatory authorities having jurisdiction, principally the ICC and the PAPUC under state public utility laws and the FERC under various Federal laws. Exelon, ComEd and PECO apply the authoritative guidance for accounting for certain types of regulation, which requires ComEd and PECO to record in their consolidated financial statements the effects of rate regulation for utility operations that meet the following criteria: (1) third-party regulation of rates; (2) cost-based rates; and (3) a reasonable expectation that all costs will be recoverable from customers through rates. Regulatory assets and liabilities are amortized in the Consolidated Statements of Operations and Comprehensive Income consistent with the recovery or refund included in customer rates. Exelon believes that it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. However, Exelon, ComEd and PECO continue to evaluate their respective abilities to apply the authoritative guidance for accounting for certain types of regulation, including consideration of current events in their respective regulatory and political environments. If a separable portion of ComEd's or PECO's business was no longer able to meet the criteria discussed above, Exelon, ComEd and PECO would be required to eliminate from their consolidated financial statements the effects of regulation for that portion, which would have a material impact on their results of operations and financial positions. See Note 2—Regulatory Matters for additional information.

Variable Interest Entities

Under the applicable authoritative guidance, VIEs are legal entities that possess any of the following characteristics: an insufficient amount of equity at risk to finance their activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or where equity holders do not receive expected losses or returns significant to the VIE. Companies are required to consolidate a VIE if they are its primary beneficiary.

Generation

Generation's wholesale operations include the physical delivery and marketing of power obtained through its generating capacity, and long-, intermediate- and short-term contracts. Generation also has contracts to purchase fuel supplies for nuclear and fossil generation. These contracts and Generation's membership in NEIL are discussed in further detail in Note 18—Commitments and Contingencies. Generation has evaluated these contracts and determined that either it has no variable interest in an entity or, where Generation does have a variable interest in an entity, it is not the primary beneficiary and, therefore, consolidation is not required.

For contracts where Generation has a variable interest, Generation has considered which interest holder has the power to direct the activities that most significantly affect the economic performance of the VIE and thus is considered the primary beneficiary and is required to consolidate the entity. The primary beneficiary must also have exposure to significant losses or the right to receive significant benefits from the VIE. In general, the most significant activity of the VIEs is the operation and maintenance of the facilities, which provides the operator with the power to direct the VIEs' activities. Facilities represent power plants, sources of uranium and fossil fuels, or plants used in the uranium conversion, enrichment and fabrication process. Generation does not have control over the operation and maintenance of the facilities considered VIEs and it does not bear operational risk of the facilities. Furthermore, Generation has no debt or equity investments in the entities, under the contracts Generation receives less than the majority of the output of the remaining expected useful life of the facilities, and Generation does not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 18—Commitments and Contingencies. Upon consideration of these factors, Generation does not consider itself to be the primary beneficiary of these VIEs and, accordingly, has determined that consolidation is not required.

Generation has historically aggregated its contracts with VIEs into two categories, energy commitments and fuel purchase obligations, based on the similar risk characteristics and significance to Generation. As of the balance sheet date, the carrying amount of assets and liabilities in Generation's Consolidated Balance Sheet that relate to its involvement with these VIEs are predominately related to working capital accounts and generally represent the amounts owed by Generation for the deliveries associated with the current billing cycles under the contracts. Further, Generation has not provided or guaranteed any debt or equity support, or any liquidity arrangements, performance guarantees or other commitments associated with these contracts, so there is no significant potential exposure to loss as a result of its involvement with the VIEs.

Several of Generation's long-term PPAs have been determined to be operating leases that have no residual value guarantees, bargain purchase options or other provisions that would cause these operating leases to be variable interests.

On December 9, 2010, Generation completed the acquisition of all of the equity interests of John Deere Renewables, LLC discussed further in Note 3—Acquisition. Generation evaluated the significant agreements and ownership structures and risks of each of the wind projects and underlying entities acquired, and determined that the entities are variable interest entities for which Generation is the primary beneficiary and consolidation is required. Each project was designed to develop, construct and operate a wind generation facility. Generation owns 100% of most projects acquired; however, 11 of the projects have noncontrolling equity interests held by others (which range between 1% and 6%). Of the 11 projects, Generation's economic interests in nine of the projects is significantly greater than its stated contractual governance rights. However, Generation has determined that its significant economic interest in the projects provides the power to direct the activities most significant to the projects. The primary factors considered in determining that Generation is the primary beneficiary were that Generation has the power to direct the operations and maintenance of the wind facilities, which is considered the activity that most significantly affects the economic performance of the projects and the obligation to absorb losses and right to receive benefits that are significant to the projects. The ownership agreements with the noncontrolling interests state that Generation provide financial support to the projects in proportion to its economic interests in the projects (which range between 99% and 94%). No additional support to these projects beyond what was contractually required has been provided during 2010. As of December 31, 2010, the carrying amount of the assets and liabilities that are consolidated as a result of Generation being the primary beneficiary of these entities primarily relate to the wind generating assets, PPA intangible assets and working capital amounts.

Generation has entered into an asset sale agreement with EnergySolutions, Inc. and certain of its subsidiaries, including ZionSolutions, LLC (ZionSolutions), which is further discussed in Note 12—Asset Retirement Obligations. Generation has evaluated this agreement and determined that it has a variable interest in ZionSolutions but is not the primary beneficiary. As a result, Generation has concluded that consolidation is not required.

ComEd and PECO

ComEd's retail operations include the purchase of electricity and RECs through procurement contracts of varying durations. PECO's retail operations include the purchase of electricity, AECs and natural gas through procurement contracts of varying durations. These contracts are discussed in further detail in Note 2—Regulatory Matters and Note 18—Commitments and Contingencies. ComEd and PECO have evaluated these contracts and determined that either there is no variable interest, or where ComEd or PECO do have a variable interest in a VIE as described below, it is not the primary beneficiary and, therefore, consolidation is not required.

For contracts where ComEd or PECO has a variable interest, consideration has been given to which interest holder has the power to direct the activities that most significantly affect the economic performance of the VIE. In general, the most significant activity of the VIEs is the operation and maintenance of their production or procurement processes related to electricity, RECs, AECs or natural gas. ComEd and PECO do not have control over the operation and maintenance of the entities considered VIEs and they do not bear operational risk related to the associated activities. Furthermore, ComEd and PECO have no debt or equity investments in the VIEs and do not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 18—Commitments and Contingencies. Accordingly, neither ComEd or PECO considers itself to be the primary beneficiary of these VIEs.

As of the balance sheet date, the carrying amounts of assets and liabilities in ComEd's and PECO's Consolidated Balance Sheet that relate to their involvement with these VIEs were predominately related to working capital accounts and generally represented the amounts owed by ComEd and PECO for the purchases associated with the current billing cycles under the contracts.

The financing trust of ComEd, ComEd Financing III, and the financing trusts of PECO, PECO Trust III and PECO Trust IV, are not consolidated in Exelon's, ComEd's or PECO's financial statements. These financing trusts were created to issue mandatorily redeemable trust preferred securities. ComEd and PECO have concluded that they do not have a variable interest in ComEd Financing III, PECO Trust III or PECO Trust IV as each Registrant financed its equity interest in the financing trusts through the issuance of subordinated debt and, therefore, has no equity at risk. ComEd and PECO, as the sponsors of the financing trusts, are obligated to pay the operating expenses of the trusts.

PECO

PETT, a financing trust, was created in 1998 by PECO to purchase and own intangible transition property (ITP) and to issue transition bonds to securitize $5 billion of PECO's stranded cost recovery authorized by the PAPUC pursuant to the Competition Act. PECO made an initial capital contribution of $25 million to PETT. ITP represented the irrevocable right of PECO to collect intangible transition charges (ITC). ITC consisted of the portion of CTCs that were sold by PECO to PETT and securitized through the various issuances of PETT's transition bonds from 1999 through 2001 as authorized by the PAPUC. ITC provided PETT with an asset sufficient to recover the aggregate principal amount of the transition bonds issued, plus amounts sufficient to provide for the credit enhancement, interest payments, servicing fees and other expenses relating to the transition bonds. PETT's assets were restricted for the sole purpose of satisfying PETT's obligation to its transition bondholders and payment of various administrative fees. PECO did not provide ongoing financial support to PETT or guarantee PETT's performance, and the transition bondholders did not have recourse to PECO. PECO had continuing involvement in PETT in its role as the servicer of the ITC collections, for which PECO received a fee. During the year ended December 31, 2010, net pre-tax losses of $16 million, related to PETT's results of operations were reflected in PECO's Consolidated Statements of Operations and Comprehensive Income.

PETT was consolidated in Exelon's and PECO's financial statements on January 1, 2010 pursuant to authoritative guidance relating to the consolidation of VIEs that became effective on that date. Under previously issued authoritative guidance, PETT was deconsolidated in accordance with a prescribed quantitative approach, based on expected losses, for determining the primary beneficiary. Under the new guidance, PECO concluded that it was the primary beneficiary of PETT due to PECO's involvement in the design of PETT, its role as servicer of the ITC collections, and its right to dissolve PETT and receive any of its remaining assets following retirement of the transition bonds and payment of PETT's other expenses. The consolidation of PETT did not have a significant impact on PECO's results of operations or statement of cash flows. Upon retirement of the outstanding transition bonds on September 1, 2010, the remaining cash balance was remitted to PECO, and PETT was dissolved on September 20, 2010. During the year ended December 31, 2010, PECO recognized interest expense on PETT's transition bonds of $22 million, which was reflected in PECO's Consolidated Statements of Operations and Comprehensive Income. See Note 10—Debt and Credit Agreements for further information regarding PETT's debt to bondholders.

Revenues

Operating Revenues. Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers. See Note 4—Accounts Receivable for further information.

RTOs and ISOs. In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, Exelon and Generation report sales and purchases conducted on a net hourly basis in either revenues or purchased power on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income, the classification of which depends on the net hourly activity. ComEd nets its spot market purchases against its spot market sales on an hourly basis, with the result recorded in purchased power expense. In 2010, 2009 and 2008, ComEd recorded an immaterial amount associated with hours where it had net spot market sales.

Option Contracts, Swaps and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense, unless hedge accounting is applied. Premiums received and paid on option contracts are recognized as revenue or expense over the terms of the contracts. If the derivatives meet hedging criteria, changes in fair value are recorded in OCI. ComEd has not elected hedge accounting for its financial swap contract with Generation. Since ComEd is entitled to full recovery of the costs of the financial swap contract in rates as settlements occur, ComEd records the fair value of the swap as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets.

Trading Activities. Exelon and Generation account for Generation's trading activities under the provisions of the authoritative guidance for accounting for contracts involved in energy trading and risk management activities, which require energy revenues and costs related to energy trading contracts to be presented on a net basis in the income statement. Commodity derivatives used for trading purposes are accounted for using the mark-to-market method with unrealized gains and losses recognized in operating revenues.

Income Taxes

Deferred Federal and state income taxes are provided on all significant temporary differences between the book basis and the tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits previously utilized for income tax purposes have been deferred on the Registrants' Consolidated Balance Sheets and are recognized in book income over the life of the related property. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more likely than not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Registrants recognize accrued interest related to unrecognized tax benefits in interest expense or in other income and deductions (interest income) on their Consolidated Statements of Operations and Comprehensive Income.

Pursuant to the IRC and relevant state taxing authorities, Exelon and its subsidiaries file consolidated or combined income tax returns for Federal and certain state jurisdictions where allowed or required. See Note 11—Income Taxes for further information.

Taxes Directly Imposed on Revenue-Producing Transactions

Exelon, ComEd and PECO present any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer on a gross (included in revenues and costs) basis. See Note 19—Supplemental Financial Information for ComEd's and PECO's utility taxes that are presented on a gross basis.

Cash and Cash Equivalents

The Registrants consider investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Investments

Restricted cash and investments represent restricted funds to satisfy designated current liabilities. As of December 31, 2010 and 2009, Exelon Corporate's restricted cash and investments primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. As of December 31, 2010 and December 31, 2009, Generation's restricted cash and investments primarily represented restricted funds for qualifying design, engineering and construction costs related to pollution control notes issued by Generation for an emissions-control facilities project and for payment of certain environmental liabilities. As of December 31, 2010 and 2009, PECO's restricted cash primarily represented funds from the sales of assets that were subject to PECO's mortgage indenture.

Restricted cash and investments not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2010 and 2009, Exelon and Generation had restricted cash and investments in the NDT funds classified as noncurrent assets. As of December 31, 2010 and 2009, ComEd had short-term investments in Rabbi trusts classified as noncurrent assets.

Allowance for Uncollectible Accounts

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable agings, historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balance by risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. ComEd and PECO customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd and PECO customer accounts are written off consistent with approved regulatory requirements. ComEd's and PECO's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC and PAPUC regulations, respectively. See Note 2—Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd.

Inventories

Inventory is recorded at the lower of cost or market. Provisions are recorded for excess and obsolete inventory.

Fossil Fuel. Fossil fuel inventory includes the weighted average costs of stored natural gas, propane, coal and oil. The costs of natural gas, propane, coal and oil are generally included in inventory when purchased and charged to fuel expense when used or sold.

Materials and Supplies. Materials and supplies inventory generally includes the average costs of transmission, distribution and generating plant materials. Materials are generally charged to inventory when purchased and expensed or capitalized to property, plant and equipment, as appropriate, when installed or used.

Emission Allowances. Emission allowances are included in inventory and other deferred debits and are carried at the lower of weighted average cost or market and charged to fuel expense as they are used in operations.

Marketable Securities

All marketable securities are reported at fair value. Marketable securities held in the NDT funds are classified as trading securities and all securities that are not held by the NDT funds are classified as available-for-sale securities. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the former ComEd and former PECO nuclear generating units (Regulatory Agreement Units) are included in regulatory liabilities at Exelon, ComEd, and PECO and in noncurrent payables to affiliates at Generation and in noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the former AmerGen nuclear generating units and the portions of the Peach Bottom nuclear generating units not subject to a regulatory agreement (Non-Regulatory Agreement Units) are included in earnings at Exelon and Generation. Unrealized gains and losses, net of tax, for ComEd's and PECO's available-for-sale securities are reported in OCI. Any decline in the fair value of ComEd's and PECO's available-for-sale securities below the cost basis is reviewed to determine if such decline is other-than-temporary. If the decline is determined to be other-than-temporary, the cost basis of the available-for-sale securities is written down to fair value as a new cost basis and the amount of the write-down is included in earnings. See Note 8—Fair Value of Financial Assets and Liabilities for further information regarding the other-than-temporary impairment recorded in the second quarter of 2009 by Exelon and ComEd related to ComEd's Rabbi trust investments. See Note 12—Asset Retirement Obligations for information regarding marketable securities held by NDT funds and Note 19—Supplemental Financial Information for additional information regarding ComEd's and PECO's regulatory assets and liabilities.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost. Original cost includes labor and materials, construction overhead, when appropriate, capitalized interest for Generation and AFUDC for regulated property at ComEd and PECO. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to maintenance expense as incurred.

Third parties reimburse ComEd and PECO for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are netted against the project costs. DOE SGIG funds reimbursed to PECO by the DOE are accounted for as CIAC.

For Generation, upon retirement, the cost of property is charged to accumulated depreciation in accordance with the composite method of depreciation. Upon replacement of an asset, the costs to remove the asset, net of salvage, is capitalized when incurred to gross plant as part of the cost of the newly installed asset and recorded to depreciation expense over the life of the new asset. Removal costs, net of salvage, incurred for property that will not be replaced is charged to expense as incurred.

For ComEd and PECO, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation in accordance with the composite method of depreciation. ComEd's depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with ComEd's regulatory recovery method. ComEd's actual incurred removal costs are applied against the related regulatory liability. PECO's removal costs are capitalized to accumulated depreciation when incurred and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method.

See Note 5—Property, Plant and Equipment, Note 6—Jointly Owned Electric Utility Plant and Note 19—Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel

The cost of nuclear fuel is capitalized and charged to fuel expense using the unit-of-production method. The estimated cost of disposal of SNF is established per the Standard Waste Contract with the DOE and is expensed through fuel expense at one mill ($.001) per kWh of net nuclear generation. On-site SNF storage costs are capitalized or expensed as incurred based upon the nature of the work performed. A portion of the storage costs are being reimbursed by the DOE since a DOE (or government owned) long-term storage facility has not been completed.

Nuclear Outage Costs

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to operating and maintenance expense or capitalized to property, plant and equipment in the period incurred.

New Site Development Costs

New site development costs represent the costs incurred in the assessment, design and construction of new power generating and transmission facilities. Such costs are capitalized when management considers project completion to be likely, primarily based on management's determination that the project is economically and operationally feasible, management and/or the Board of Directors have approved the project and have committed to a plan to develop it, and Exelon and Generation have received the required regulatory approvals or management believes the receipt of required regulatory approvals is probable. Upon commencement of construction, these costs will be charged to construction work in progress. Capitalized development costs are charged to operating and maintenance expense when project completion is no longer probable. At December 31, 2010, Exelon and Generation's capitalized development costs totaled approximately $20 million, which are included in Property, Plant and Equipment on Exelon and Generation's Consolidated Balance Sheets. These costs primarily include land rights and other third-party costs directly associated with the development of certain Exelon Wind projects. At December 31, 2009, there were no significant costs capitalized related to new site development. Approximately $6 million, $23 million and $26 million of costs were expensed by Exelon and Generation for the years ended December 31, 2010, 2009 and 2008, respectively, primarily related to the possible construction of a new nuclear plant in Texas.

Capitalized Software Costs

Costs incurred during the application development stage of software projects that are developed or obtained for internal use are capitalized. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives, pursuant to regulatory approval or requirement. The following table presents net unamortized capitalized software costs and amortization of capitalized software costs by year:

Net unamortized software costs	
December 31, 2010	$312
December 31, 2009	279
Amortization of capitalized software costs	
2010	$104
2009	105
2008	91

Depreciation and Amortization

Except for the amortization of nuclear fuel, depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the composite method. ComEd's depreciation includes a provision for estimated removal costs as authorized by the ICC. The estimated service lives for ComEd and PECO are primarily based on the average service lives from the most recent depreciation study for each respective company. The estimated service lives of the nuclear-fuel generating facilities are based on the remaining useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses (to the extent that such renewal has not yet been granted) for all of Generation's operating nuclear generating stations except for Oyster Creek. See Note 18—Commitments and Contingencies for information regarding Oyster Creek. The estimated service lives of the hydroelectric generating facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the operating licenses. The estimated service lives of the fossil fuel and other renewable generating facilities are based on the remaining useful lives of the stations, which Generation periodically evaluates based on feasibility assessments taking into account economic and capital requirement considerations. See Note 5—Property, Plant and Equipment for further information regarding depreciation.

Amortization of regulatory assets is recorded over the recovery period specified in the related legislation or regulatory agreement. See Notes 2—Regulatory Matters and 19—Supplemental Financial Information for additional information regarding Generation's nuclear fuel, Generation's ARC and the amortization of ComEd's and PECO's regulatory assets.

Asset Retirement Obligations

The authoritative guidance for accounting for AROs requires the recognition of a liability for a legal obligation to perform an asset retirement activity even though the timing and/or method of settlement may be conditional on a future event. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years. Generation generally updates its ARO annually based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios. The liabilities associated with Exelon's non-nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years, due to the passage of new laws and regulations and revisions to either the timing or amount of estimates of undiscounted cash flows and estimates of cost escalation factors. AROs are accreted each year to reflect the time value of money for these present value obligations through a charge to operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income or, in the case of the majority of ComEd's and PECO's accretion, through an increase to regulatory assets. See Note 12—Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC

Exelon and Generation capitalize during construction the costs of debt funds used to finance non-regulated construction projects.

Exelon, ComEd and PECO apply the authoritative guidance for accounting for certain types of regulation to calculate AFUDC, which is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded as a charge to construction work in progress and as a non-cash credit to AFUDC that is included in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

The following table summarizes total cost incurred, capitalized interest and credits of AFUDC by year:

	2010	2009	2008
Total incurred interest [(a)]	$861	$786	$867
Capitalized interest	38	50	34
Credits to AFUDC debt and equity	16	14	2

(a) Includes interest expense to affiliates.

Guarantees

The Registrants recognize, at the inception of a guarantee, a liability for the fair market value of the obligations they have undertaken in issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced as the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 18—Commitments and Contingencies for additional information.

Asset Impairments

Long-Lived Assets. Exelon, Generation, ComEd, and PECO evaluate the carrying value of their long-lived assets, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. See Note 5—Property, Plant and Equipment for a discussion of asset impairment evaluations made by Generation.

Goodwill. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is tested for impairment at least annually or on an interim basis if an event occurs or circumstances change that could reduce the fair value of a reporting unit below its carrying value. See Note 7—Intangible Assets for additional information regarding Exelon's and ComEd's goodwill.

Derivative Financial Instruments

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting, changes in the fair value of the derivatives are recognized in earnings each period. For energy-related derivatives entered into for proprietary trading purposes, which are subject to Exelon's Risk Management Policy, changes in the fair value of the derivatives are recognized in earnings each period. Amounts classified in earnings are included in revenue, purchased power and fuel, or Other, net on the Consolidated Statements of Operations and Comprehensive Income. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statement of Cash Flows, depending on the underlying nature of the Registrants' hedged items.

Revenues and expenses on contracts that qualify, and are designated, as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and price is not tied to an unrelated underlying derivative. As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be recorded on the balance sheet and immediately recognized through earnings at Generation or offset by a regulatory asset or liability at ComEd and PECO. See Note 9—Derivative Financial Instruments for additional information.

Retirement Benefits

Generation, ComEd and PECO participate in Exelon's defined benefit pension plans and other postretirement plans. AmerGen sponsored a separate defined benefit pension plan and postretirement plan for its employees until the merger of AmerGen into Generation on January 8, 2009. Exelon became the sponsor of those plans at that date.

The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, including numerous assumptions and accounting elections. The assumptions are reviewed annually and at any interim remeasurement of the plan obligations. The impact of assumption changes on pension and other postretirement benefit obligations is generally recognized over the expected average remaining service period of the employees rather than immediately recognized in the income statement. See Note 13—Retirement Benefits for additional discussion of Exelon's accounting for retirement benefits.

New Accounting Pronouncements

Exelon has identified the following new accounting pronouncements that have been recently adopted or issued that may affect the Registrants upon adoption.

Transfers of Financial Assets

In June 2009, the FASB issued authoritative guidance amending the accounting for the transfers of financial assets. Key provisions include (i) the removal of the concept of qualifying special purpose entities, (ii) the introduction of the concept of a participating interest, in circumstances in which a portion of a financial asset has been transferred and (iii) the requirement that to qualify for sale accounting, the transferor must evaluate whether it maintains effective control over transferred financial assets either directly or indirectly. Furthermore, this guidance required enhanced disclosures about transfers of financial assets and a transferor's continuing involvement. This guidance was effective for the Registrants beginning January 1, 2010 and was required to be applied prospectively. See Note 10—Debt and Credit Agreements for discussion regarding the application of this guidance as it relates to PECO's accounts receivable agreement.

Consolidation of Variable Interest Entities

In June 2009, the FASB issued authoritative guidance to amend the manner in which entities evaluate whether consolidation is required for VIEs. The model for determining which enterprise has a controlling financial interest and is the primary beneficiary of a VIE has changed significantly under the new guidance. Previously, variable interest holders had to determine whether they had a controlling financial interest in a VIE based on a quantitative analysis of the expected gains and/or losses of the entity. In contrast, the new guidance requires an enterprise with a variable interest in a VIE to qualitatively assess whether it has a controlling financial interest in the entity, and if so, whether it is the primary beneficiary. Furthermore, this guidance requires that companies continually evaluate VIEs for consolidation rather than assessing based upon the occurrence of triggering events. This revised guidance also requires enhanced disclosures about how a company's involvement with a VIE affects its financial statements and exposure to risks. This guidance became effective for the Registrants on January 1, 2010. See further discussion of the Registrants' VIEs and the impact of adopting this new guidance above.

Fair Value Measurements Disclosures

In January 2010, the FASB issued authoritative guidance intended to improve disclosures about fair value measurements. The guidance requires entities to disclose significant transfers in and out of fair value hierarchy levels and the reasons for the transfers and to present information about purchases, sales, issuances and settlements separately in the reconciliation of fair value measurements using significant unobservable inputs (Level 3). Additionally, the guidance clarifies that a reporting entity should provide fair value measurements for each class of assets and liabilities and disclose the inputs and valuation techniques used for fair value measurements using significant other observable inputs (Level 2) and significant unobservable inputs (Level 3). This guidance was effective for interim and annual periods beginning after December 15, 2009 except for the disclosures about purchases, sales, issuances and settlements in the Level 3 reconciliation, which is effective for interim and annual periods beginning after December 15, 2010. As this guidance provided only disclosure requirements, the adoption of this standard did not impact the Registrants' results of operations, cash flows or financial positions.

Credit Quality of Financing Receivables and Allowance for Credit Losses Disclosures

In July 2010, the FASB issued authoritative guidance requiring entities to disclose additional information about their allowance for uncollectible accounts and the credit quality of their financing receivables, which include loans defined as a contractual right to receive money, on demand or on fixed or determinable dates, with terms exceeding one year. The additional disclosure requirements include the nature of the credit risk inherent in their financing receivables balance, how the risk is analyzed and assessed in determining the allowance for uncollectible accounts, and the changes and reasons for changes in the allowance for uncollectible accounts. This guidance is applicable to PECO's long-term installment plan receivables and was effective for the

Registrants on December 31, 2010. As this guidance provides only additional disclosure requirements, the adoption of this standard did not impact the Registrants' results of operations, cash flows or financial position. See the discussion of the Registrants' allowance for uncollectible accounts policy above and Note 4—Accounts Receivable for further information.

Revenue Arrangements with Multiple Deliverables

In October 2009, the FASB issued authoritative guidance that amends existing guidance for identifying separate deliverables in a revenue-generating transaction where multiple deliverables exist, and provides guidance for allocating and recognizing revenue based on those separate deliverables. The guidance is expected to result in more multiple-deliverable arrangements being separable than under current guidance. This guidance was effective for the Registrants beginning on January 1, 2011 and is required to be applied prospectively to new or significantly modified revenue arrangements. The Registrants have concluded that this guidance will not have a material impact on their results of operations, cash flows or financial position.

Disclosure of Supplementary Pro Forma Information for Business Combinations

In December 2010, the FASB issued authoritative guidance amending the existing guidance for the disclosure of supplementary pro forma information for business combinations. The guidance specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only, rolled forward through the current period. Additionally, the guidance expands required supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination. This guidance is effective for the Registrants beginning on January 1, 2011 and is required to be applied prospectively to business combinations that are considered material on an individual or aggregated basis. As this guidance provides only additional disclosure requirements, the adoption of this standard will not impact the Registrants' results of operations, cash flows or financial position.

2. Regulatory Matters

The following matters below discuss, in all material respects, the current status of regulatory and legislative proceedings of the Registrants.

Illinois Regulatory Matters

Appeal of 2007 Illinois Electric Distribution Rate Case. The ICC issued an order in ComEd's 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd's annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a return on ComEd's distribution rate base using a weighted average debt and equity return of 8.36%, an increase over the 8.01% return authorized in the previous rate case. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). The Court issued a decision on September 30, 2010, ruling against ComEd on the treatment of post-test year accumulated depreciation and the recovery of costs for an AMI/Customer Applications pilot program via a rider (Rider SMP). On November 18, 2010, the Court denied ComEd's petition for rehearing in connection with the September 30, 2010 ruling. On January 25, 2011, ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court.

The Court held the ICC abused its discretion in not reducing ComEd's rate base to account for an additional 18 months of accumulated depreciation while including post–test year pro forma plant additions through that period (the same position ComEd has taken in its 2010 electric distribution rate case (2010 Rate Case) discussed below). The Court's ruling, absent reversal following further proceedings, may trigger a refund obligation. The ICC will ultimately be required to set a just and reasonable rate which will determine the amount of any refund. The impact on ComEd's rates and any associated refund obligation should be prospective from no earlier than the date of the Court's ruling on September 30, 2010. ComEd will continue to bill rates as established under the ICC's order in the 2007 Rate Case, but will recognize for accounting purposes its estimate of any refund obligation, subject to true–up when the ICC establishes a new rate. An interest charge may accrue on any refund amount. ComEd recorded an estimated refund obligation of $17 million as of December 31, 2010.

The Court also reversed the ICC's approval of ComEd's Rider SMP, a program which included the installation of 131,000 smart meters in the Chicago area. The Court held that the ICC's approval of Rider SMP constituted illegal single–issue ratemaking. The Court's decision prescribes a new, more stringent standard for cost–recovery riders not specifically authorized by statute. Such riders would be allowed only if: (1) the pass–through cost is imposed by an "external circumstance" and is unexpected, volatile, or fluctuating; and (2) recovery via rider does not change other expenses or increase utility income. As a result of the Court's ruling on Rider SMP, ComEd reclassified $6 million of regulatory assets to property, plant and equipment for costs to retire early meters replaced with smart meters during ComEd's AMI/Customer Applications pilot. This is consistent with the composite method of depreciation and recovery of capitalized expenditures. ComEd also recorded a $4 million (pre–tax) write–off of regulatory assets associated with operating and maintenance costs that were originally allowable under Rider SMP, as the costs can no longer be recovered from customers. ComEd does not believe any of its other riders are affected by the Court's ruling.

Subsequent to the Court's ruling, ComEd filed a request with the ICC to allow it to request recovery, through inclusion in the 2010 Rate Case, of $3 million in operation and maintenance costs, as well as carrying costs associated with capital investment in the ICC-approved AMI/Customer Applications pilot program. The Rider SMP pilot program capital investment had already been requested in rate base in the 2010 Rate Case. On December 2, 2010, the ICC approved ComEd's request. The investment and the pilot program costs are subject to challenge in the 2010 Rate Case proceeding.

2010 Illinois Electric Distribution Rate Case. On June 30, 2010, ComEd requested ICC approval for an increase of $396 million to its annual delivery services revenue requirement. On January 3, 2011, ComEd filed surrebuttal testimony which adjusted ComEd's requested annual revenue requirement increase to $326 million to account for recent changes in tax law, corrections, acceptance of limited adjustments proposed by certain parties and the amounts expected to be recovered in the AMI pilot program tariff discussed above. The request to increase the annual revenue requirement is to allow ComEd to continue modernizing its electric delivery system and recover the costs of substantial investments made since its last rate filing in 2007. The requested increase also reflects increased costs, most notably pension and OPEB, since ComEd's rates were last determined. The requested rate of return on common equity is 11.5%. The requested increase in electric distribution rates would increase the average residential customer's monthly electric bill by approximately 5%. In addition, ComEd is requesting future recovery of certain amounts that were previously recorded as expense. If that request is approved, ComEd would reverse the previously expensed costs and establish regulatory assets with amortization over the period during which rate recovery is allowed. As a result, ComEd would recognize a one-time benefit of up to $39 million (pre-tax) to reverse the prior charges. The requested increase also includes $22 million for increased uncollectible accounts expense. If the rate request is approved, the threshold for determining over/under recoveries under ComEd's uncollectible accounts tariff would be increased by $22 million.

The Court's September 30, 2010 ruling in connection with ComEd's 2007 Rate Case makes it highly unlikely that the ICC would decide the post-test year accumulated depreciation issue in ComEd's favor in the 2010 Rate Case. ComEd estimates that its requested revenue requirement increase of $326 million could be reduced by approximately $85 million as a result of this adjustment. Certain parties have submitted testimony recommending significant reductions to ComEd's requested increase as well as the write-off of certain assets, most notably the regulatory asset associated with severance costs, which was approximately $74 million as of December 31, 2010. Management believes the regulatory asset is appropriate based on the ICC's orders in ComEd's last two rate cases. The new electric distribution rates are expected to take effect no later than June 2011. ComEd cannot predict how much of the requested electric distribution rate increase the ICC may approve.

Illinois Legislation Authorizing Recovery of Uncollectible Accounts. In 2009, comprehensive legislation was enacted into law in Illinois providing public utility companies with the ability to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and amounts collected in rates annually through a rider mechanism, starting with 2008 and prospectively. On February 2, 2010, the ICC issued an order adopting ComEd's proposed tariffs filed in accordance with the legislation, with minor modifications. As a result of that ICC order, ComEd recorded a regulatory asset of $70 million and an offsetting reduction in operating and maintenance expense in the first quarter of 2010 for the cumulative under–collections in 2008 and 2009. Recovery of the regulatory asset associated with 2008 and 2009 activities is over an approximate 14–month time frame, which began in April 2010. The recovery or refund of the difference in the uncollectible accounts expense applicable to each year after 2009 is over a 12–month time frame beginning in June of the following year. In addition, ComEd recorded a one–time charge of $10 million to operating and maintenance expense in the first quarter of 2010 for a contribution to the Supplemental Low–Income Energy Assistance Fund as required by the legislation. The fund is used to assist low–income residential customers.

Illinois Procurement Proceedings. ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Beginning on January 1, 2007, ComEd procured all energy to meet its load service requirements through ICC-approved staggered SFCs with various suppliers, including Generation. Since June 2009, under the Illinois Settlement Legislation, the IPA designs, and the ICC approves an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. In order to fulfill a requirement of the Illinois

Settlement Legislation, ComEd hedged the price of a significant portion of energy purchased in the spot market with a five-year variable-to-fixed financial swap contract with Generation that expires on May 31, 2013.

On December 28, 2009, the ICC approved the IPA's procurement plan covering the period June 2010 through May 2015. As of December 31, 2010, ComEd had completed the ICC-approved procurement process for a portion of its energy requirements through May 2012. The remainder of ComEd's expected energy requirements through May 2012 will be met through additional Block Contracts resulting from future RFP processes or purchased through the spot market and hedged by the financial swap contract with Generation.

The Illinois Settlement Legislation requires ComEd to purchase an increasing percentage of its electricity requirements from renewable energy resources. As of December 31, 2010, the ICC had approved the results of ComEd's 2010 RFPs to procure RECs for the period from June 2010 through May 2011 and to procure long-term RECs for a 20 year period starting in June 2012. On December 17, 2010, ComEd entered into 20-year contracts with several unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. The long term renewables purchased will count towards satisfying ComEd's obligation under the state's RPS and all associated costs will be recoverable from customers.

On December 2, 2010, the ICC approved ComEd's reconciliation of the actual costs of power purchased in the January 2007 through May 2008 period with the costs for power that flowed through ComEd's tariffs and were collected from customers. The ICC has initiated a similar proceeding to reconcile the actual costs of power purchased in the June 2008 through May 2009 period. Because the Illinois Settlement Legislation has already deemed such costs to be prudently incurred, the reconciliation proceeding is not expected to have a significant impact on ComEd.

See Notes 9—Derivative Financial Instruments for additional information regarding ComEd's financial swap contract with Generation and long-term renewable energy contracts.

Illinois Settlement Legislation. The Illinois Settlement Legislation was signed into law in August 2007 following a settlement resulting from extensive discussions with legislative leaders in Illinois, ComEd, Generation and other utilities and generators in Illinois to address concerns about higher electric bills in Illinois without rate freeze, generation tax or other legislation that Exelon believes would be harmful to consumers of electricity, electric utilities, generators of electricity and the State of Illinois. Various Illinois electric utilities, their affiliates and generators of electricity in Illinois agreed to contribute approximately $1 billion over a period of four years that ended in 2010 to programs to provide rate relief to Illinois electricity customers and funding for the IPA. ComEd committed to issue $64 million in rate relief credits to customers or to fund various programs to assist customers. Generation committed to contribute an aggregate of $747 million, consisting of $435 million to pay ComEd for rate relief programs for ComEd customers, $307.5 million for rate relief programs for customers of other Illinois utilities and $4.5 million for partially funding operations of the IPA. The contributions were recognized in the financial statements of Generation and ComEd as rate relief credits were applied to customer bills by ComEd and other Illinois utilities or as operating expenses associated with the programs were incurred. As of December 31, 2010, Generation and ComEd had fulfilled their commitments under the Illinois Settlement Legislation.

During the years ended December 31, 2010, 2009 and 2008, Generation and ComEd recognized net costs from their contributions pursuant to the Illinois Settlement Legislation in their Consolidated Statements of Operations and Comprehensive Income as follows:

Year Ended December 31, 2010	Generation	ComEd	Total Credits Issued to ComEd Customers
Credits to ComEd customers [(a)]	$ 14	$ 1	$ 15
Credits to other Illinois utilities' customers [(a)]	7	n/a	n/a
Total incurred costs	$ 21	$ 1	$ 15

Year Ended December 31, 2009	Generation	ComEd	Total Credits Issued to ComEd Customers
Credits to ComEd customers [(a)]	$ 45	$ 8	$ 53
Credits to other Illinois utilities' customers[(a)]	53	n/a	n/a
Other rate relief programs [(b)]	—	1	n/a
Total incurred costs	$ 98	$ 9	$ 53

Year Ended December 31, 2008	Generation	ComEd	Total Credits Issued to ComEd Customers
Credits to ComEd customers [(a)]	$131	$ 6	$137
Credits to other Illinois utilities' customers [(a)]	90	n/a	n/a
Other rate relief programs [(b)]	—	7	n/a
Total incurred costs	$221	$ 13	$137

(a) Recorded as a reduction in operating revenues.
(b) Recorded as a charge to operating and maintenance expense.

Energy Efficiency and Renewable Energy Resources. As a result of the Illinois Settlement Legislation, electric utilities in Illinois are required to include cost-effective energy efficiency resources in their plans to meet an incremental annual program energy savings requirement of 0.2% of energy delivered to retail customers for the year ended June 1, 2009, which increases annually to 2% of energy delivered in the year commencing June 1, 2015 and each year thereafter. Additionally, during the ten year period that began June 1, 2008, electric utilities must implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers. The energy efficiency and demand response goals are subject to rate impact caps each year. Utilities are allowed recovery of costs for energy efficiency and demand response programs, subject to approval by the ICC. In February 2008, the ICC issued an order approving substantially all of ComEd's first three-year Energy Efficiency and Demand Response Plan, including cost recovery. This plan began in June 2008 and goes through May 2011. In December 2010, the ICC approved ComEd's second three-year Efficiency and Demand Response Plan covering the period June 2011 through May 2014. The plans are designed to meet the Illinois Settlement Legislation's energy efficiency and demand response goals through May 2014, including reductions in delivered energy to all retail customers and in the peak demand of eligible retail customers.

Since June 1, 2008, utilities have been required to procure cost-effective renewable energy resources in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers. ComEd is also required to acquire amounts of renewable energy resources that will cumulatively increase this percentage to at least 10% by June 1, 2015, with an ultimate target of at least 25% by June 1, 2025, subject to customer rate cap limitations. All goals are subject to rate impact criteria set forth in the Illinois Settlement Legislation. As of December 31, 2010, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. ComEd currently retires all RECs immediately upon purchase. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates. See Note 18—Commitments and Contingencies for information regarding ComEd's future commitments for the procurement of RECs.

Pennsylvania Regulatory Matters

2010 Pennsylvania Electric and Natural Gas Distribution Rate Cases. On March 31, 2010, PECO filed separate petitions before the PAPUC for increases of $316 million and $44 million to its annual service revenue requirement for electric and natural gas distribution, respectively, to fund critical infrastructure improvement projects to meet customer demand and ensure the safe and reliable delivery of electricity and natural gas. Costs related to customer assistance discount programs are also included in the annual service revenue requirement. These costs were previously transferred to Generation under the PPA, which expired on December 31, 2010. On December 16, 2010, the PAPUC approved the settlement of PECO's electric and natural gas distribution rate cases for increases in annual service revenue of $225 million and $20 million, respectively. The settlements do not impact recoverability of PECO's regulatory assets currently recorded and the electric settlement provides for recovery of PJM transmission service costs, on a full and current basis through a rider. The settlements include a stipulation regarding how expected tax benefits related to anticipated IRS guidance on repairs allowance deduction methodology are to be handled from a rate-making perspective. The settlements require the expected cash benefit from the application of the new methodology to prior tax years be refunded to customers over a seven-year period. The prospective tax benefit claimed as a result of the new methodology is to be reflected in tax expense in the year in which it is claimed on the tax return and will be reflected in the determination of revenue requirements in the next electric and natural gas distribution base rate cases. The approved electric and natural gas distribution rates became effective on January 1, 2011.

The 2010 electric distribution rate case settlement did not specify the rate of return upon which the settlement rates are based, but rather provided for an increase in annual revenue. PECO's most recently approved weighted average debt and equity return on electric rate base, which included electric transmission, distribution and generation, was 11.23% (approved in 1990). PECO has not filed a transmission rate case since rates have been unbundled. PECO's purchased gas cost rates are not subject to caps and do not earn a return. The 2008 and 2010 natural gas distribution rate case settlements did not specify the rate of return upon which the settlement rates are based, but rather provided for an increase in annual revenue.

2008 Pennsylvania Natural Gas Distribution Rate Case. In October 2008, the PAPUC approved the settlement related to PECO's natural gas distribution rate case, which was filed in March 2008 providing an increase of $77 million to its annual natural gas distribution revenue. As part of the settlement, PECO agreed to enhance its low-income programs as well as provide funding for new energy-efficiency programs to help customers manage their energy usage and gas bills. The approved natural gas distribution rates became effective on January 1, 2009.

Nuclear Decommissioning Funding. In 2009, the PAPUC entered an order instituting an investigation into whether PECO's nuclear decommissioning cost adjustment clause (NDCAC), which is a rider that allows PECO to collect funds from customers for future decommissioning costs of seven former PECO nuclear units now owned by Generation, should continue after December 31, 2010. During the course of the investigation, PECO and the interested parties reached an agreement, as set forth in a Stipulation and Joint Memorandum filed on February 24, 2010 (Settlement) that PECO is entitled to recovery from customers through the NDCAC beyond December 31, 2010 for the funding of future decommissioning costs. The Settlement also contained a provision in which it was agreed that PECO would not claim recovery under the NDCAC for any projected incremental physical decommissioning costs with respect to any former PECO nuclear unit as a result of an extension of that unit's NRC operating license. On July 15, 2010, the PAPUC approved the Settlement. See Note 12—Asset Retirement Obligations for additional information.

Pennsylvania Procurement Proceedings. In 2009, the PAPUC approved PECO's DSP Program, under which PECO will provide default electric service following the expiration of electric generation rate caps on December 31, 2010. The DSP Program, which has a 29-month term beginning January 1, 2011 and ending May 31, 2013, complies with electric supply procurement guidelines set forth in Act 129. Under the DSP Program, PECO is permitted to recover its electric procurement costs from retail default service customers without mark-up through the GSA. The GSA provides for the recovery of energy, capacity, ancillary costs and administrative costs and is subject to adjustments at least quarterly for any over or under collections. The filing and implementation costs of the DSP program have been recorded as a regulatory asset and are recoverable through the GSA over its 29-month term. During 2010, PECO entered into contracts with PAPUC-approved bidders for its third and fourth competitive procurements of electric supply for default electric service commencing January 2011, which included fixed price full requirement contracts for all procurement classes, spot market price full requirements contracts for the commercial and industrial procurement classes, and block energy contracts for the residential procurement class. Under the full requirements contracts, default service suppliers must provide electric supply, capacity, transmission other than Network Integration Transmission Service, ancillary services, transmission and distribution losses, congestion management costs and AECs for compliance with the AEPS Act. As of December 31, 2010, including the previous competitive procurements completed in 2009 and 2010, the 2011 expected energy requirements for all customer classes have been substantially procured. PECO will conduct five additional competitive procurements over the remainder of the term of the DSP Program.

The hourly spot market priced full requirement tranches for large commercial and industrial default service customers in the September 2010 procurement were not fully subscribed. PECO intends to serve the associated load through direct purchases from the PJM spot market and separately procured AEPS credits, for the period beginning January 1, 2011 through May 31, 2011. PECO will solicit bids for the unsubscribed hourly spot market price full requirements procurement tranches for its large commercial and industrial customer class in its next default service procurement occurring in May 2011.

As part of the 2009 settlement of the DSP Program, PECO filed a Revised Electric Purchase of Receivables (POR) program that requires PECO to purchase the customer accounts receivable of EGSs that participate in the electric customer choice program and have elected consolidated billing by PECO. The Revised Electric POR program was filed on November 20, 2009, and provided for full recovery of PECO's system implementation costs for program administration through a temporary discount on purchased receivables. On June 16, 2010, the PAPUC approved PECO's settlement of the electric POR program. The approved settlement states that PECO can terminate electric service to customers beginning January 1, 2011, based on unpaid charges for EGS service, and uncollectible accounts expense will be recovered from customers through distribution rates. Receivables purchased under the POR program will be classified in other accounts receivable, net on Exelon and PECO's Consolidated Balance Sheets and could significantly increase as a result of PECO's transition to market-based rates.

Smart Meter and Smart Grid Investments. In 2009, PECO filed a joint petition with the PAPUC for partial settlement of its $550 million Smart Meter Procurement and Installation Plan to install more than 1.6 million smart meters and deploy advanced communication networks over a 15-year period. On April 22, 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan that provides for recovery through a rider for program expenses on a full and current basis and the accelerated depreciation incurred on existing meters due to early deployment over the period January 1, 2011 through December 31, 2020. The rider that provides recovery of the costs of new meters placed in service includes a 10.5% equity return. PECO filed for PAPUC approval of an initial dynamic pricing and customer acceptance program in October 2010, and plans to file for approval of a universal meter deployment plan for its remaining customers in 2012.

On April 12, 2010, PECO entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA. Under the SGIG, PECO has been awarded $200 million, the maximum grant allowable under the program, for its SGIG project—Smart Future Greater Philadelphia. As a result of the SGIG funding, PECO will deploy 600,000 smart meters within three years, accelerate universal deployment of more than 1.6 million smart meters from 15 years to 10 years and increase smart grid investments to approximately $100 million over the next three years. The $200 million SGIG funds will be reimbursed ratably based on projected spending of more than $400 million, which includes approximately $7 million related to demonstration projects by two sub-recipients. The SGIG is non-taxable based on IRS guidance. The DOE has a conditional ownership interest in Federally-funded project property and equipment, which is subordinate to PECO's existing mortgage. In total, over the next 10 years, PECO is planning to spend up to a total of $650 million on its smart grid and smart meter infrastructure. During 2010, PECO entered into agreements for an AMI network, AMI systems, installation of the first 600,000 meters, and procurement of meters and fiber-cable. The $200 million SGIG from the DOE will be used to significantly reduce the impact of those investments on PECO ratepayers.

As of December 31, 2010, PECO has incurred project expenditures of $34 million that are reimbursable from the DOE, which have been recorded in other accounts receivable, net on PECO's Consolidated Balance Sheets.

Energy Efficiency Programs. Pursuant to Act 129's EE&C reduction targets, PECO filed its EE&C plan with the PAPUC and received partial approval in 2009. In February 2010, the PAPUC approved PECO's revisions to the EE&C plan. The approved plan set forth how PECO will reduce electric consumption by at least 1% in its service territory by May 31, 2011 from expected consumption for the period June 1, 2009 through May 31, 2010 and by 3% by May 31, 2013. In accordance with Act 129, PECO also plans to reduce peak demand by a minimum of 4.5% of PECO's annual system peak demand in the 100 hours of highest demand by May 31, 2013, measured against its peak demand during the period of June 1, 2007 through May 31, 2008. If PECO fails to achieve the required reductions in consumption within the stated deadlines, PECO will be subject to civil penalties of up to $20 million, which would not be recoverable from ratepayers. As of December 31, 2010, PECO has met the 1% consumption reduction target for 2011.

The approved four-year plan, which began on June 1, 2009, totals more than $330 million and includes a CFL program, weatherization programs, an energy efficiency appliance rebate and trade-in program, rebates and energy efficiency programs for non-profit, educational, governmental and business customers, customer incentives for energy management programs and incentives to help customers reduce energy demand during peak periods. In September 2010, PECO filed revisions to the EE&C Plan previously approved in February 2010 that included adjustments to certain incentive levels and the addition of energy efficiency measures to the existing portfolio. These revisions do not impact the total spending under the approved EE&C plan or timely cost recovery from ratepayers. On January 27, 2011, the PAPUC unanimously approved PECO's EE&C Plan revisions.

Alternative Energy Portfolio Standards. In November 2004, Pennsylvania adopted the AEPS Act. The AEPS Act mandated that beginning in 2011, following the expiration of PECO's rate cap transition period, certain percentages of electric energy sold to Pennsylvania retail electric customers shall be generated from certain alternative energy resources as measured in AECs. The requirement for electric energy that must come from Tier I alternative energy resources (including solar, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, fuel cells, biomass energy, coal mine methane and black liquor generated within Pennsylvania) ranges from approximately 3.5% to 8.0% and the requirement for Tier II alternative energy resources (including waste coal, demand-side management, large-scale hydropower, municipal solid waste, generation of electricity utilizing by-products of the pulping process and wood, distributed generation systems and integrated combined coal gasification technology) ranges from 6.2% to 10.0%. The required compliance percentages incrementally increase each PJM year until May 31, 2021. These Tier I and Tier II alternative energy resources include acceptable energy sources as set forth in Act 129 in addition to those outlined in the AEPS Act.

In 2007 and 2009, the PAPUC approved PECO's plan under which PECO entered into five-year and ten-year agreements with accepted bidders, including Generation, totaling 452,000 non-solar and 8,000 solar Tier I AECs annually. The AECs procured prior to the 2011 compliance year were banked and are anticipated to be used to meet AEPS obligations through May 2013. All administrative costs incurred in connection with AEC procurement prior to 2011 have been deferred as a regulatory asset with a return on the unamortized balance and will be recovered from customers in 2011. Those costs, and PECO's AEPS Act compliance costs incurred thereafter, will be recovered from customers on a full and current basis through a rider as contemplated by the AEPS Act. In November 2010, PECO filed a petition with the PAPUC for approval of procurement of Tier II AECs to satisfy PECO's compliance requirements for the AEPS reporting years ending 2011 and 2012.

Federal Regulatory Matters

Transmission Rate Case. ComEd's transmission rates are established based on a FERC–approved formula. ComEd's formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 9.27%, a decrease from the 9.43% return previously authorized. As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.5% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the formula transmission rate is currently capped at 56%. This equity cap will be reduced to 55% in June 2011.

ComEd's most recent annual formula rate update filed in May 2010 reflects actual 2009 expenses and investments plus forecasted 2010 capital additions. The update resulted in a revenue requirement of $430 million offset by a $14 million reduction related to the true–up of 2009 actual costs for a net revenue requirement of $416 million. This compares to the May 2009 updated net revenue requirement of $440 million. The decrease in the revenue requirement was primarily driven by ComEd's 2009 cost savings measures. The 2010 net revenue requirement became effective June 1, 2010 and is recovered over the period extending through May 31, 2011. The regulatory liability associated with the true–up is being amortized as the associated amounts are refunded.

PJM Transmission Rate Design. PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd and PECO incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. In the short term, based on new transmission facilities approved by PJM, it is likely that allocating across PJM the costs of new facilities 500 kV and above will increase charges to ComEd and reduce charges to PECO, as compared to the allocation methodology in effect before the FERC order. After FERC ultimately denied all requests for rehearing on all issues, several parties filed petitions in the U.S. Court of Appeals for the Seventh Circuit for review of the decision. On August 6, 2009, the court issued its decision affirming FERC's order with regard to the costs of existing facilities but reversing and remanding to FERC for further consideration its decision with regard to the costs of new facilities 500 kV and above. On January 21, 2010, FERC issued an order establishing paper hearing procedures to supplement the record. In May and June 2010, certain parties, including Exelon, submitted testimony to supplement the record. ComEd anticipates that all impacts of any rate design changes effective after December 31, 2006 should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on ComEd's results of operations, cash flows or financial position. PECO anticipates that all impacts of any rate design changes should be recoverable through the transmission service charge rider approved in PECO's 2010 electric distribution rate case settlement and, thus, the rate design changes are not expected to have a material impact on PECO's results of operations, cash flows or financial position. To the extent any rate design changes are retroactive to periods prior to January 1, 2011 there may be an impact on PECO's results of operation.

Market-Based Rates. Generation, ComEd and PECO are public utilities for purposes of the Federal Power Act and are required to obtain FERC's acceptance of rate schedules for wholesale electricity sales. Currently, Generation, ComEd and PECO have authority to execute wholesale electricity sales at market-based rates. As is customary with market-based rate schedules, FERC has reserved the right to suspend market-based rate authority on a retroactive basis if it subsequently determines that Generation, ComEd or PECO has violated the terms and conditions of its tariff or the Federal Power Act. FERC is also authorized to order refunds if it finds that the market-based rates are not just and reasonable under the Federal Power Act.

As required by FERC's regulations, as promulgated in the Order No. 697 series, Generation, ComEd and PECO have filed market power analyses using the prescribed market share screens to demonstrate that Generation, ComEd and PECO qualify for market-based rates in the regions where they are selling energy and capacity under market-based rate tariffs. FERC accepted the 2008 filings on January 15, 2009 and September 2, 2009 and accepted the 2009 filing on October 26, 2009, affirming Exelon's affiliates continued right to make sales at market-based rates. These analyses must examine historic test period data and must be updated every three years on a prescribed schedule. The most recent updated analysis for the PJM and Northeast Regions was filed in late 2010, based on 2009 historic test period data. In that updated analysis, Generation informed FERC that its market share data in PJM would change beginning in 2011, when Generation's contract for PECO's full requirements for capacity and energy expired. That change, as well as any new sales contracts or other intervening changes in Generation's market share, will be reflected in the next updated market share screen analysis due to be filed at the end of 2013. In the meantime, under FERC's rules and precedent, any market power concerns would be obviated by FERC-approved RTO market monitoring and mitigation program in PJM.

Reliability Pricing Model. On December 22, 2006, FERC approved a contested settlement establishing a competitive auction mechanism for forward sales of capacity to serve PJM's capacity requirements. The settlement provided for an auction 36 months in advance of each delivery year beginning with the delivery year ending May 31, 2012 and an expedited phase-in process for four transitional auctions covering delivery years ending on May 31 in 2008 through 2011. All but one appeal of FERC's order approving RPM were withdrawn on February 27, 2009 and the remaining appeal was denied by the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) on March 17, 2009.

PJM's transitional RPM auctions took place 36 months ahead of the scheduled delivery year. The most recent auction for the delivery year ending May 31, 2014 occurred in May 2010. Thus far, the RPM capacity auctions have secured capacity for the PJM market through 2014. While auction results produced varying prices, as anticipated, the RPM has been beneficial for owners of generation facilities, particularly for such facilities located in constrained zones, as compared to the prior capacity-payment construct.

On May 30, 2008, a group of PJM load-serving entities, state commissions, consumer advocates and trade associations (referred to collectively as the RPM Buyers) filed a complaint at FERC against PJM alleging that three of the four transitional RPM auctions yielded prices that are unjust and unreasonable under the Federal Power Act. Most of the parties comprising the RPM Buyers group were parties to the settlement approved by FERC that established the RPM. In the complaint, the RPM Buyers requested that the total projected payments to RPM sellers for the three auctions at issue be materially reduced. The FERC's dismissal of the complaint was appealed to the D.C. Circuit. On February 8, 2011, the D.C. Circuit denied the petition for review. While the RPM Buyers may file for rehearing of this decision and/or appeal it to the U.S. Supreme Court, the likelihood of reversal is minimal. Therefore, Exelon and Generation believe that it is remote that the ultimate outcome of this matter will have a material adverse impact on their respective results of operations, cash flows or financial position.

License Renewals. On April 8, 2009, the NRC issued a renewed operating license for Oyster Creek that expires in April 2029. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. See Note 18—Commitments and Contingencies for additional information.

On October 22, 2009, the NRC issued a renewed operating license for TMI Unit 1 that expires in April 2034.

On August 18, 2009, PSEG submitted an application to the NRC to extend the operating license of Salem Units 1 and 2 by 20 years. Exelon is part owner of the Salem Units. The NRC is expected to spend a total of 22 to 30 months to review the application before making a decision. The current operating licenses expire in 2016 and 2020, respectively.

Regulatory Assets and Liabilities

Exelon, ComEd and PECO prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd and PECO as of December 31, 2010 and 2009.

December 31, 2010	Exelon	ComEd	PECO
Regulatory assets			
Pension and other postretirement benefits	$2,763	$ —	$ 13
Deferred income taxes	852	23	829
Smart meter program expenses	17	—	17
Debt costs	123	108	15
Severance	74	74	—
Asset retirement obligations	86	61	25
MGP remediation costs	149	110	39
RTO start-up costs	10	10	—
Under-recovered uncollectible accounts	14	14	—
Financial swap with Generation—noncurrent	—	525	—
DSP Program costs	7	—	7
Other	45	22	23
Noncurrent regulatory assets	4,140	947	968
Financial swap with Generation—current	—	450	—
Under-recovered energy and transmission costs current asset	6	6	—
DSP Program electric procurement contracts—current	4	—	9
Total regulatory assets	$4,150	$1,403	$ 977
Regulatory liabilities			
Nuclear decommissioning	$2,267	$1,892	$ 375
Removal costs	1,211	1,211	—
Refund of PURTA taxes	4	—	4
Energy efficiency and demand response programs	69	31	38
Other	4	3	1
Noncurrent regulatory liabilities	3,555	3,137	418
Over-recovered energy and transmission costs current liability	44	19	25
Total regulatory liabilities	$3,599	$3,156	$ 443

December 31, 2009	Exelon	ComEd	PECO
Regulatory assets			
Competitive transition charges	$ 883	$ —	$ 883
Pension and other postretirement benefits	2,634	—	19
Deferred income taxes	842	20	822
Debt costs	144	125	19
Severance	95	95	—
Asset retirement obligations	65	49	16
MGP remediation costs	143	103	40
RTO start-up costs	12	12	—
Financial swap with Generation—noncurrent	—	669	—
DSP Program electric procurement contracts	2	—	4
DSP Program costs	5	—	5
Other	47	23	26
Noncurrent regulatory assets	4,872	1,096	1,834
Financial swap with Generation—current	—	302	—
Under-recovered energy and transmission costs current asset	56	56	—
Total regulatory assets	$4,928	$1,454	$1,834

December 31, 2009	Exelon	ComEd	PECO
Regulatory liabilities			
Nuclear decommissioning	$2,229	$1,918	$311
Removal costs	1,212	1,212	—
Refund of PURTA taxes	4	—	4
Deferred taxes	30	—	—
Energy efficiency and demand response programs	15	15	—
Other	2	—	2
Noncurrent regulatory liabilities	3,492	3,145	317
Over-recovered energy and transmission costs current liability	33	11	22
Total regulatory liabilities	$3,525	$3,156	$339

Competitive transition charges. These charges represent PECO's stranded costs that the PAPUC determined would be recoverable under the Competition Act through electric generation rates, which included a 10.75% return on the unamortized balance, over the transition period. These costs were related to generation assets that would no longer be recoverable through regulated rates due to the deregulation of the generation portion of the electric utility business in Pennsylvania. These charges were fully amortized as of December 31, 2010, which coincided with the end of the transition period.

Pension and other postretirement benefits. As of December 31, 2010, $2,750 million represents regulatory assets related to the recognition of ComEd's and PECO's respective shares of the underfunded status of Exelon's defined benefit postretirement plans as a liability on Exelon's balance sheet. The regulatory asset is amortized in proportion to the recognition of prior service costs (gains), transition obligations and actuarial losses attributable to ComEd's pension plan and ComEd's and PECO's other postretirement benefit plans determined by the cost recognition provisions of the authoritative guidance for pensions and postretirement benefits. ComEd and PECO will recover these costs through base rates as allowed in their most recently approved regulated rate orders. See Note 13—Retirement Benefits for additional detail. In addition, $13 million is the result of PECO transitioning to the current authoritative guidance in 1993, which is recoverable in rates through 2012. ComEd and PECO are not earning a return on the recovery of these costs in base rates.

Deferred income taxes. These costs represent the difference between the method by which the regulator allows for the recovery of income taxes and how income taxes would be recorded under GAAP. Regulatory assets and liabilities associated with deferred income taxes, recorded in compliance with the authoritative guidance for accounting for certain types of regulation and income taxes, include the deferred tax effects associated principally with liberalized depreciation accounted for in accordance with the ratemaking policies of the ICC and PAPUC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future transmission and distribution rates. See Note 11—Income Taxes for additional information. ComEd and PECO are not earning a return on the recovery of these costs.

Smart meter program expenses. These costs represent accelerated depreciation, filing and implementation costs relating to PECO's PAPUC approved Smart Meter Procurement and Installation Plan. The approved plan allows for recovery of filing and implementation costs incurred through December 31, 2010 during 2011 and 2012. In addition, the approved plan provides for recovery of program costs beginning in January 2011 on full and current basis, which includes interest income or expense of 6% on the under or over recovery, and recovery of accelerated depreciation on PECO's current meter reading assets over a 10 year period ending December 31, 2020. To the extent that PECO deploys smart meters sooner than required to replace existing meters and meter communication modules, it will incur accelerated depreciation on these existing meters and modules.

Debt costs. Consistent with rate recovery for ratemaking purposes, ComEd's and PECO's recoverable losses on reacquired long-term debt related to regulated operations are deferred and amortized to interest expense over the life of the new debt issued to finance the debt redemption or over the life of the original debt issuance if the debt is not refinanced. Interest-rate swap settlements are deferred and amortized over the period that the related debt is outstanding or the life of the original issuance retired. These debt costs are used in the determination of the weighted cost of capital applied to rate base in the rate-making process.

Severance. These costs represent previously incurred severance costs that ComEd was granted recovery of in the December 20, 2006 ICC rehearing rate order. The recovery period is through June 30, 2014. ComEd is not earning a return on these costs.

Asset retirement obligations. These costs represent future removal costs associated with ComEd's and PECO's existing asset retirement obligations. PECO will begin to earn a return on, and a recovery of, these costs once the removal activities have been performed. ComEd will recover these costs through future depreciation expense and will earn a return on these costs once the removal activities have been performed. See Note 12—Asset Retirement Obligations for additional information.

MGP remediation costs. Recovery of these items was granted to ComEd in the July 26, 2006 ICC rate order. For PECO, these costs are recoverable through rates as prescribed in the 2008 and 2010 approved natural gas distribution rate case settlements. The period of recovery for both ComEd and PECO will depend on the timing of the actual expenditures. ComEd and PECO are not earning a return on the recovery of these costs. See Note 18—Commitments and Contingencies for additional information.

RTO start-up costs. Recovery of these RTO start-up costs was approved by FERC. The recovery period is through March 31, 2015. ComEd is earning a return on these costs.

Under-recovered uncollectible accounts. As a result of the February 2010 ICC order approving recovery of ComEd's uncollectible accounts, ComEd has the ability to adjust its rates annually to reflect the increases and decreases in annual uncollectible accounts expense starting with year 2008. ComEd recorded a regulatory asset for the cumulative under-collections in 2008 and 2009. Recovery of the initial regulatory asset will take place over an approximate 14-month time frame which began in April 2010. The recovery or refund of the difference in the uncollectible accounts expense applicable to the years starting with January 1, 2010, will take place over a 12–month time frame beginning in June of the following year. ComEd is not earning a return on these costs.

Financial swap with Generation. To fulfill a requirement of the Illinois Settlement Legislation, ComEd entered into a five-year financial swap contract with Generation that expires on May 31, 2013. Since the swap contract was deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period are recorded by ComEd as well as an offsetting regulatory asset or liability. ComEd does not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd's cost to purchase energy on the spot market and the contracted price. In Exelon's consolidated financial statements, the fair value of the intercompany swap recorded by Generation and ComEd is eliminated.

Rate case costs. The ICC generally allows ComEd to receive recovery of rate case costs over three years. The ICC has issued orders allowing recovery of these costs on July 26, 2006 and September 10, 2008. The recovery period is through September 15, 2011. Pursuant to the approved settlement of the 2010 electric distribution rate case, PECO is allowed recovery of rate case costs over two years ending December 31, 2012. Pursuant to the approved settlements of the 2010 and 2008 natural gas distribution rate cases, PECO is allowed recovery of rate case costs over two years ending December 31, 2012 and 2010, respectively. ComEd and PECO do not earn a return on the recovery of these costs.

DSP Program electric procurement contracts. These amounts represent an offset to the mark-to-market liability position of PECO's procurement contracts for electric supply following the expiration of its generation rate caps on December 31, 2010. Recovery of electric procurement costs through the GSA, adjusted quarterly, was granted to PECO in the PAPUC approval of their DSP Program and will begin in 2011. This regulatory asset will be unwound against the mark-to-market liability over the relevant contract period beginning January 1, 2011 therefore, no return is earned.

DSP Program costs. These amounts represent administrative costs incurred relating to filing, procurement, and information technology improvements associated with the procurement of electric supply following the expiration of PECO's generation rate caps on December 31, 2010. Recovery of these costs was granted to PECO in the PAPUC approval of their DSP Program. The filing and implementation costs of the DSP Program are recoverable through the GSA over a 29-month period beginning January 1, 2011. The independent evaluator costs associated with conducting procurements is recoverable over a 12-month period beginning January 1, 2011. Costs relating to information technology improvements will be recovered over a 5-year period beginning January 1, 2011. PECO earns a 6% return on the recovery of information technology costs.

Under (over)-recovered energy and transmission costs current asset (liability). Starting in 2007, ComEd energy and transmission costs are recoverable (refundable) under ComEd's ICC and/or FERC-approved rates. ComEd's deferred energy and transmission costs are earning (paying) a rate of return. The PECO costs represent gas supply related costs recoverable (refundable) under PECO's PAPUC-approved rates. PECO earns interest of 6% on the under-recovered energy costs and pays interest of 8% on over-recovered energy costs to customers.

Nuclear decommissioning. These amounts represent future nuclear decommissioning costs that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. Exelon believes the trust fund assets, including prospective earnings thereon and any future collections from customers, will equal the associated future decommissioning costs at the time of decommissioning. See Note 12—Asset Retirement Obligations for additional information.

Removal costs. These amounts represent funds ComEd has received from customers to cover the future removal of property, plant and equipment which reduces rate base for ratemaking purposes.

Refund of PURTA taxes. In October 2009, PECO prevailed in a Pennsylvania Commonwealth Court case in which PECO had contested the assessment of a PURTA supplemental tax applicable to 1997. As a result, PECO will receive approximately $4 million of previously remitted real estate taxes in 2011 and must pass this refund on to customers. PECO will begin amortizing this regulatory liability and refunding the amount to customers in January 2011. No interest or return will be paid to customers.

Energy efficiency and demand response programs. These amounts represent costs recoverable (refundable) under ComEd's ICC approved Energy Efficiency and Demand Response Plan and PECO's PAPUC approved EE&C Plan. ComEd began recovering these costs or refunding over-collections of these costs on June 1, 2008 through a rider. ComEd earns a return on the capital investment incurred under the program but does not earn (pay) a return on under (over) collections. PECO began recovering these costs through a rider on full and current basis on January 1, 2010. Recovery will continue over the life of the program, which expires on May 31, 2013. As of December 31, 2010, PECO's revenues related to the EE&C exceeded program spend.

Operating and Maintenance for Regulatory Required Programs

The following tables set forth costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through a rider for ComEd and PECO for the years ended December 31, 2010, 2009 and 2008. An equal and offsetting amount has been reflected in operating revenues during the periods.

	For the year ended December 31,		
	2010	2009	2008
Energy efficiency and demand response programs	$135[a]	$ 59[a]	$ 25[a]
Advanced metering infrastructure pilot program	5	—	—
Purchased power administrative costs	4	4	—
Consumer education program	3	—	3
Total operating and maintenance for regulatory required programs	$147	$ 63	$ 28

(a) As a result of the Illinois Settlement, utilities are required to provide energy efficiency and demand response programs.
(b) Represents recovered costs under PECO's energy efficiency and conservation/demand plan, which began in 2010, that was designed to meet Act 129's energy efficiency and conservation/demand reduction targets.
(c) In 2009, the PAPUC authorized PECO to collect a surcharge to recover expenditures associated with PECO's approved consumer education plan related to the transition to competitive energy market prices.

3. Acquisition

On December 9, 2010, Generation completed the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind), a leading operator and developer of wind power. Under the terms of the agreement, Generation acquired 735 MWs of installed, operating wind capacity located in eight states. The acquisition builds on the Exelon's commitment to renewable energy as part of Exelon 2020, a business and environmental strategy to eliminate the equivalent of Exelon's 2001 carbon footprint.

The fair value of assets acquired and liabilities assumed was determined based upon the use of significant estimates and assumptions that are judgmental in nature. Some of the more significant estimates and assumptions used include: projected future cash flows (including timing); discount rates reflecting the risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and the duration of the liabilities assumed. Generation did not record any goodwill related to the acquisition of Exelon Wind.

The following table summarizes the fair value of consideration transferred to acquire Exelon Wind and the value of identified assets and liabilities assumed as of the acquisition date:

Fair Value of Consideration Transferred

Cash [a]	$893
Contingent consideration	32
Total fair value of consideration recorded	$925

Recognized amounts of identifiable assets acquired and liabilities assumed

Property, plant and equipment	$700
Intangible assets [(b)]	224
Working capital	18
Asset retirement obligations	(13)
Noncontrolling interest	(3)
Other	(1)
Total net identifiable assets	$925

(a) On September 30, 2010, Generation issued $900 million of senior notes, the proceeds of which were used to fund the acquisition. See Management's Discussion and Analysis of Financial Condition and Result of Operations, Liquidity and Capital Resources for additional information regarding the debt issuance.
(b) See Note 7—Intangible Assets for additional information.

The contingent consideration arrangement requires that Generation pay up to $40 million related to three individual projects with a capacity of 230 MWs, which are currently in advanced stages of development, upon meeting certain contractual commitments related to the commencement of construction of each project. The fair value of the contingent consideration arrangement of $32 million was determined based upon a weighted average probability of meeting certain contractual commitments related to the commencement of construction of each project, which is considered an unobservable (Level 3) input pursuant to applicable accounting guidance. As of December 31, 2010, the amount recognized for the contingent consideration arrangement, the range of outcomes, and the assumptions used to develop the estimate had not changed since the December 9, 2010 acquisition date. Generation anticipates paying a portion of the contingent consideration within the next 12 months, and accordingly, has recorded $16 million of contingent consideration in other current liabilities within Exelon and Generation's Consolidated Balance Sheets. The remaining amount was recorded in other deferred credits and other liabilities within Exelon and Generation's Consolidated Balance Sheets.

The fair value of the assets acquired includes customer receivables of $24 million, which represent all amounts due under the related contracts as of the acquisition date. Generation expects these receivables to be collected in the normal course of business. Generation did not acquire any other receivables as part of the Exelon Wind acquisition.

The $3 million noncontrolling interest represents the noncontrolling members' proportionate share in the fair value of the assets acquired and liabilities assumed in the transaction.

Exelon Wind's revenue and operating income contribution to Exelon and Generation for the period from December 10, 2010 to December 31, 2010 was not material. The unaudited pro forma results for Exelon and Generation as if the Exelon Wind acquisition occurred on January 1, 2009 were not materially different from Exelon and Generation's financial results for years ended December 31, 2010 and December 31, 2009.

In 2010, Exelon and Generation incurred $11 million of acquisition-related costs associated with this transaction. These costs are included within operating and maintenance expense in Exelon and Generation's Consolidated Statements of Comprehensive Income.

4. Accounts Receivable

Accounts receivable at December 31, 2010 and 2009 included estimated unbilled revenues, representing an estimate for the unbilled amount of energy or services provided to customers, and is net of an allowance for uncollectible accounts as follows:

	2010	2009
Unbilled revenues	$1,060	$1,035
Allowance for uncollectible accounts	(228)[(a)]	(225)

(a) Includes an allowance for uncollectible accounts of $19 million related to PECO's installment plan receivables described below.

PECO Installment Plan Receivables. PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The receivables balance for installment plans with terms greater than one year was $22 million, net of an allowance for uncollectible accounts of $19 million as of December 31, 2010. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1—Significant Accounting Policies. The allowance for uncollectible accounts balance at December 31, 2010 of $19 million consists of $1 million, $5 million and $13 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of December 31, 2010 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults under the payment agreement, the terms of which are defined by plan type, the entire balance under the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1—Significant Accounting Policies.

Accounts Receivable Agreement. PECO is party to an agreement with a financial institution under which it sold an undivided interest, adjusted daily, in up to $225 million of designated accounts receivable which is accounted for as a secured borrowing. As of December 31, 2010, the financial institution's undivided interest in Exelon and PECO's gross accounts receivable was equivalent to $346 million, which is calculated under the terms of the agreement. See Note 10—Debt and Credit Agreements for additional information regarding the accounts receivable agreement.

5. Property, Plant and Equipment

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2010 and 2009:

	Average Service Life (years)	2010	2009
Asset Category			
Electric—transmission and distribution	5-75	$20,389	$19,441
Electric—generation (a)	1-55	11,914	9,666
Gas—transportation and distribution	5-66	1,732	1,679
Common—electric and gas	5-50	534	517
Nuclear fuel (b)	1-8	3,725	3,340
Construction work in progress	N/A	1,290	1,263
Other property, plant and equipment (c)	4-50	421	458
Total property, plant and equipment		40,005	36,364
Less: accumulated depreciation (d)		10,064	9,023
Property, plant and equipment, net		$29,941	$27,341

(a) Includes Exelon Wind assets. See Note 3—Acquisition for additional information.

(b) Includes nuclear fuel that is in the fabrication and installation phase of $651 million and $711 million at December 31, 2010 and 2009, respectively.

(c) Includes Generation's buildings under capital lease with a net carrying value of $26 million and $29 million at December 31, 2010 and 2009, respectively. The original cost basis of the buildings was $53 million and total accumulated amortization was $27 million and $24 million as of December 31, 2010 and 2009, respectively. Also includes unregulated property at ComEd and PECO.

(d) Includes accumulated depreciation related to regulated property at ComEd and PECO of $4,955 million and $4,565 million as of December 31, 2010 and 2009, respectively. Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $1,592 million and $1,383 million as of December 31, 2010 and 2009, respectively. On December 2, 2009, Generation announced its intention to permanently retire four of its fossil-fired generating units. Exelon recorded approximately $80 million and $32 million as of December 31, 2010 and 2009, respectively, of additional depreciation expense to reflect changes in useful lives for the plant assets that will be taken out of service prior to their previously estimated service period. See Note 14—Corporate Restructuring and Plant Retirements for additional information.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2010	2009	2008
Electric—transmission and distribution	2.53%	2.43%	2.42%
Electric—generation	2.86%	2.28%	2.02%
Gas	1.75%	1.75%	1.74%
Common—electric and gas	7.25%	6.41%	6.51%

6. Jointly Owned Electric Utility Plant

Exelon's, Generation's and PECO's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2010 and 2009 were as follows:

	Nuclear generation			Fossil fuel generation			Transmission		Other
	Quad Cities	Peach Bottom	Salem (a)	Keystone	Conemaugh	Wyman	PA (b)	DE/NJ (c)	Other (d)
Operator	Generation	Generation	PSEG Nuclear	Reliant	Reliant	FP&L	First Energy	PSEG	
Ownership interest	75.00%	50.00%	42.59%	20.99%	20.72%	5.89%	Various	42.55%	44.24%
Exelon's share at December 31, 2010:									
Plant	$ 709	$ 566	$ 395	$ 360	$ 247	$ 3	$ 8	$ 60	$ 1
Accumulated depreciation	124	274	96	128	152	2	5	29	—
Construction work in progress	63	88	72	3	11	0	—	—	—
Exelon's share at December 31, 2009:									
Plant	$ 570	$ 520	$ 386	$ 357	$ 236	$ 3	$ 5	$ 60	$ 1
Accumulated depreciation	101	263	79	119	151	2	4	28	—
Construction work in progress	107	56	46	1	11	—	—	—	—

(a) Generation also owns a proportionate share in the fossil fuel combustion turbine at Salem, which is fully depreciated. The gross book value was $3 million at December 31, 2010 and 2009.
(b) PECO owns a 22% share in 127 miles of 500,000 voltage lines located in Pennsylvania; PECO also owns a 20.7% share of a 500kv substation immediately outside of the Conemaugh fossil generating station which supplies power to the 500,000 voltage lines noted above.
(c) PECO owns a 42.55% share in 131 miles of 500,000 voltage lines located in Delaware and New Jersey.
(d) Generation has a 44.24% ownership interest in Merrill Creek Reservoir located in New Jersey.

Exelon's, Generation's and PECO's undivided ownership interests are financed with their funds and all operations are accounted for as if such participating interests were wholly owned facilities. Exelon's, Generation's and PECO's share of direct expenses of the jointly owned plants are included in fuel and operating and maintenance expenses on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and in operating and maintenance expenses on PECO's Consolidated Statements of Operations and Comprehensive Income.

7. Intangible Assets

Goodwill

Exelon's gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2010 and 2009 were as follows:

	2010			2009		
	Gross Amount [(a)]	Accumulated Impairment Losses	Carrying Amount	Gross Amount [(a)]	Accumulated Impairment Losses	Carrying Amount
Balance, January 1	$4,608	$1,983	$2,625	$4,608	$1,983	$2,625
Impairment losses	—	—	—	—	—	—
Balance, December 31,	$4,608	$1,983	$2,625	$4,608	$1,983	$2,625

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom merger net of amortization, resolution of tax matters and other non-impairment-related changes as allowed under previous authoritative guidance.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually, or more frequently if events or circumstances indicate that goodwill might be impaired. The impairment assessment is performed using a two-step, fair value based test. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

Exelon assesses goodwill impairment at its ComEd reporting unit. Accordingly, any goodwill impairment charge at ComEd will affect Exelon's consolidated results of operations. As a result of new authoritative guidance for fair value measurement effective January 1, 2009, Exelon and ComEd now estimate the fair value of the ComEd reporting unit using a weighted combination of a discounted cash flow analysis and a market multiples analysis instead of the expected cash flow approach used in 2008 and prior years. The discounted cash flow analysis relies on a single scenario reflecting "base case" or "best estimate" projected cash flows for ComEd's business and includes an estimate of ComEd's terminal value based on these expected cash flows using the generally accepted Gordon Dividend Growth formula, which derives a valuation using an assumed perpetual annuity based on the entity's residual cash flows. The discount rate is based on the generally accepted Capital Asset Pricing Model and represents the weighted average cost of capital of comparable companies. The market multiples analysis utilizes multiples of business enterprise value to earnings, before interest, taxes, depreciation and amortization (EBITDA) of comparable companies in estimating fair value. Significant assumptions used in estimating the fair value include discount and growth rates, utility sector market performance and transactions, operating and capital expenditure requirements and the fair value of debt. Management performs a reconciliation of the sum of the estimated fair value of all Exelon reporting units to Exelon's enterprise value based on its trading price to corroborate the results of the discounted cash flow analysis and the market multiple analysis.

2010 Annual Goodwill Impairment Assessment. The 2010 annual goodwill impairment assessment was performed as of November 1, 2010. The first step of the annual impairment analysis, comparing the fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill, therefore the second step was not required. Although the fair value of the reporting unit currently exceeds its carrying value, adverse regulatory actions that could reduce ComEd's allowed long-term rate of return on common equity or a fully successful IRS challenge to Exelon's and ComEd's like-kind exchange income tax position could potentially result in a future impairment loss of ComEd's goodwill, which could be material. In addition, deterioration in market related factors used in the impairment review discussed above could also potentially cause a future impairment loss.

Prior Goodwill Impairment Assessments. The 2009 and 2008 annual goodwill impairment assessments were performed as of November 1, 2009 and November 1, 2008, respectively. In each case, the first step of the annual impairment analysis, comparing the fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill, therefore the second step was not required.

Other Intangible Assets

Exelon's, other intangible assets, included in deferred debits and other assets in their Consolidated Balance Sheets, consisted of the following as of December 31, 2010:

	Gross	Accumulated Amortization	Net	Estimated amortization expense 2011	2012	2013	2014	2015
Exelon Wind acquisition [(a)]	$224	$ (1)	$223	$12	$13	$14	$14	$14
Chicago settlement—1999 agreement [(b)]	100	(66)	34	3	3	3	3	3
Chicago settlement—2003 agreement [(c)]	62	(27)	35	4	4	4	4	4
Total intangible assets	$386	$(94)	$292	$19	$20	$21	$21	$21

(a) Refer to Note 3—Acquisition for additional information regarding Exelon Wind.
(b) In March 1999, ComEd entered into a settlement agreement with the City of Chicago associated with ComEd's franchise agreement. Under the terms of the settlement, ComEd agreed to make payments to the City of Chicago each year from 1999 to 2002. The intangible asset recognized as a result of these payments is being amortized ratably over the remaining term of the franchise agreement, which ends in 2020.
(c) In February 2003, ComEd entered into separate agreements with the City of Chicago and with Midwest Generation, LLC (Midwest Generation). Under the terms of the settlement agreement with the City of Chicago, ComEd agreed to pay the City of Chicago a total of $60 million over a ten-year period, beginning in 2003. The intangible asset recognized as a result of the settlement agreement is being amortized ratably over the remaining term of the City of Chicago franchise agreement, which ends in 2020. As required by the settlement, ComEd also made a payment of $2 million to a third party on the City of Chicago's behalf. Pursuant to the agreement discussed above, ComEd received payments of $32 million from Midwest Generation to relieve Midwest Generation's obligation under the 1999 fossil sale agreement with ComEd to build the generation facility in the City of Chicago. The payments received by ComEd, which have been recorded in other long-term liabilities, are being recognized ratably (approximately $2 million annually) as an offset to amortization expense over the remaining term of the franchise agreement.

The following table summarizes the amortization expense related to intangible assets for each of the years ended December 31, 2010, 2009 and 2008:

	Exelon
2010	$8
2009	7
2008	7

John Deere Renewables. Accounting guidance requires that the acquirer must recognize separately identifiable intangible assets in the application of purchase accounting. The output of the acquired wind turbines has been sold under PPA contracts. The excess of the contract price of the PPAs over market prices was recognized as intangible assets. Generation determined that the estimated acquisition-date fair value of the intangible assets was approximately $224 million, which was recorded in other deferred debits and other assets within Exelon's Consolidated Balance Sheets. Included in this amount is $48 million related to the PPAs for the projects that are in the advanced stage of development. While Generation expects to perform under the PPAs once the construction of these projects is complete, there is a risk of impairment if the projects do not reach commercial operation. The valuation of the acquired intangible assets was estimated by applying the income approach, which is based upon discounted projected future cash flows associated with the PPA contracts. That measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include forecasted power prices and discount rate. The intangible assets will be amortized on a straight-line basis over the period in which the associated contract revenues are recognized. Generation determined that the unit of production amortization method would best reflect when the intangible assets' economic benefits would be consumed; however, the straight-line method approximates the equivalent of the unit of production method on an annual basis. The amortization expense will be reflected as a decrease in operating revenue within Exelon's Consolidated Statements of Operations and Comprehensive Income. The weighted-average amortization period for these intangibles is approximately 18 years.

Renewable Energy Credits and Alternative Energy Credits. Exelon's, Generation's, and PECO's other intangible assets, included in other current assets and other deferred debits and other assets on the Consolidated Balance Sheets, include RECs (Exelon and Generation) and AECs (PECO). As of December 31, 2010, PECO had current and noncurrent AECs of $10 million and $11 million, respectively. As of December 31, 2009, PECO had noncurrent AECs of $13 million. As of December 31, 2010 and December 31, 2009, the balances of RECs for Generation, which are considered noncurrent, were $8 million and $6 million, respectively. See Note 2—Regulatory Matters and Note 18—Commitments and Contingencies for additional information on RECs and AECs.

8. Fair Value of Financial Assets and Liabilities

Non-Derivative Financial Assets and Liabilities. As of December 31, 2010 and 2009, Exelon's carrying amounts of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities are representative of fair value because of the short-term nature of these instruments.

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The carrying amounts and fair values of Exelon's long-term debt and SNF obligation as of December 31, 2010 and 2009 were as follows:

	2010		2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (including amounts due within one year)	$12,213	$12,960	$11,634	$12,223
Long-term debt to PETT due within one year	—	—	415	426
Long-term debt to financing trusts	390	350	390	325
Spent nuclear fuel obligation	1,018	876	1,017	832
Preferred securities of subsidiary	87	68	87	63

Fair values of long-term debt are determined by a valuation model, which is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. The fair value of preferred securities of subsidiaries is determined using observable market prices as these securities are actively traded. The carrying amount of Exelon's and Generation's SNF obligation resulted from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. Exelon's and Generation's obligation to the DOE accrues at the 13-week Treasury rate and fair value was determined by comparing the carrying amount of the obligation at the 13-week Treasury rate to the present value of the obligation discounted using the prevailing Treasury rate for a long-term obligation with an estimated maturity of 2020 (after being adjusted for Generation's credit risk).

Recurring Fair Value Measurements

To increase consistency and comparability in fair value measurements, the FASB established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1—quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to access as of the reporting date. Financial assets and liabilities utilizing Level 1 inputs include active exchange-traded equity securities, exchange-based derivatives, mutual funds and money market funds.
- Level 2—inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. Financial assets and liabilities utilizing Level 2 inputs include fixed income securities, non-exchange-based derivatives, commingled investment funds priced at NAV per fund share and fair value hedges.
- Level 3—unobservable inputs, such as internally developed pricing models for the asset or liability due to little or no market activity for the asset or liability. Financial assets and liabilities utilizing Level 3 inputs include infrequently traded non-exchange-based derivatives.

There were no significant transfers between Level 1 and Level 2 during the years ended December 31, 2010 and 2009. See Note 13—Retirement Benefits for further information regarding the fair value and related valuation techniques for pension and postretirement plan assets.

The following tables present assets and liabilities measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2010 and 2009:

As of December 31, 2010	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$1,473	$ —	$—	$ 1,473
Nuclear decommissioning trust fund investments				
Cash equivalents	1	—	—	1
Equity securities [b]	1,513	—	—	1,513
Commingled funds [c]	—	2,212	—	2,212
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	504	96	—	600
Debt securities issued by states of the United States and political subdivisions of the states	—	451	—	451
Corporate debt securities	—	619	—	619
Federal agency mortgage-backed securities	—	804	—	804
Commercial mortgage-backed securities (non-agency)	—	114	—	114
Residential mortgage-backed securities (non-agency)	—	14	—	14
Other debt obligations	—	48	—	48
Nuclear decommissioning trust fund investments subtotal [d]	2,018	4,358	—	6,376
Pledged assets for Zion decommissioning				
Equity securities [b]	84	—	—	84
Commingled funds [c]	—	132	—	132
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	166	12	—	178
Debt securities issued by states of the United States and political subdivisions of the states	—	45	—	45
Corporate debt securities	—	263	—	263
Federal agency mortgage-backed securities	—	102	—	102
Commercial mortgage-backed securities (non-agency)	—	14	—	14
Other debt obligations	—	2	—	2
Pledged assets for Zion decommissioning subtotal [e]	250	570	—	820
Rabbi trust investments				
Mutual funds [f]	36	—	—	36
Rabbi trust investments subtotal	36	—	—	36
Mark-to-market derivative assets				
Cash flow hedges	—	724	12	736
Other derivatives	2	1,709	57	1,768
Proprietary trading	—	235	46	281
Effect of netting and allocation of collateral [g]	(3)	(1,848)	(38)	(1,889)
Mark-to-market (liabilities) assets [h]	(1)	820	77	896
Total assets	3,776	5,748	77	9,601
Liabilities				
Mark-to-market derivative liabilities				
Cash flow hedges	—	(45)	—	(45)
Other derivatives	(2)	(667)	(29)	(698)
Proprietary trading	—	(233)	(21)	(254)
Effect of netting and allocation of collateral [g]	1	914	23	938
Mark-to-market liabilities [h]	(1)	(31)	(27)	(59)
Deferred compensation	—	(76)	—	(76)
Total liabilities	(1)	(107)	(27)	(135)
Total net assets	$3,775	$ 5,641	$ 50	$ 9,466

As of December 31, 2009	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [(a)]	$1,845	$ —	$—	$1,845
Nuclear decommissioning trust fund investments				
Cash equivalents	2	120	—	122
Equity securities [(b)]	1,528	—	—	1,528
Commingled funds [(c)]	—	2,086	—	2,086
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	511	119	—	630
Debt securities issued by states of the United States and political subdivisions of the states	—	454	—	454
Corporate debt securities	—	710	—	710
Federal agency mortgage-backed securities	—	887	—	887
Commercial mortgage-backed securities (non-agency)	—	91	—	91
Residential mortgage-backed securities (non-agency)	—	9	—	9
Other debt obligations	—	76	—	76
Nuclear decommissioning trust fund investments subtotal [(d)]	2,041	4,552	—	6,593
Rabbi trust investments				
Cash equivalents	28	—	—	28
Mutual funds [(f)]	13	—	—	13
Rabbi trust investments subtotal	41	—	—	41
Mark-to-market derivative net (liabilities) assets [(g)(h)]	(4)	852	(44)	804
Total assets	3,923	5,404	(44)	9,283
Liabilities				
Deferred compensation	—	(82)	—	(82)
Servicing liability	—	—	(2)	(2)
Total liabilities	—	(82)	(2)	(84)
Total net assets (liabilities)	$3,923	$5,322	$(46)	$9,199

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.

(b) Generation's NDT funds and Zion Station decommissioning pledged assets hold equity portfolios whose performance is benchmarked against established indices.

(c) Generation's NDT funds and Zion Station decommissioning pledged assets own commingled funds that invest in equity securities. Generation's NDT funds also own commingled funds that invest in fixed income securities. The commingled funds seek to out-perform certain established indices.

(d) Excludes net assets of $32 million and $76 million at December 31, 2010 and 2009, respectively. These items consist of receivables related to pending securities sales net of cash, interest receivables and payables related to pending securities purchases.

(e) Excludes net assets of $4 million at December 31, 2010. These items consist of receivables related to pending securities sales net of cash, interest receivables and payables related to pending securities purchases.

(f) Excludes $25 million and $23 million of the cash surrender value of life insurance investments at December 31, 2010 and December 31, 2009, respectively.

(g) Includes collateral postings received from counterparties. Collateral received from counterparties, net of collateral paid to counterparties, totaled $2 million, $934 million and $15 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2010. Collateral received from counterparties, net of collateral paid to counterparties, totaled $3 million, $941 million and $3 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2009.

(h) The Level 3 balance does not include current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $450 million and $525 million at December 31, 2010 and $302 million and $669 million at December 31, 2009, respectively, related to the fair value of Generation's financial swap contract with ComEd; and a current asset for Generation and current liability for PECO of $5 million at December 31, 2010 and a noncurrent asset for Generation and noncurrent liability for PECO of $2 million at December 31, 2009, respectively, related to the fair value of Generation's block contracts with PECO, which eliminate upon consolidation in Exelon's Consolidated Financial Statements.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2010 and 2009:

For the Year Ended December 31, 2010 [(a)]	Servicing Liability	Nuclear Decommissioning Trust Fund Investments	Mark-to-Market Derivatives	Total
Balance as of January 1, 2010	$ (2)	$—	$(44)	$(46)
Total realized / unrealized gains				
Included in income	2[(d)]	—	46[(b)]	48
Included in other comprehensive income	—	—	16[(c)]	16
Included in regulatory assets/liabilities	—	—	2	2
Change in collateral	—	—	(10)	(10)
Purchases, sales, issuances and settlements				
Purchases	—	13	15	28
Sales	—	(1)	—	(1)
Transfers out of Level 3	—	(12)	25	13
Balance as of December 31, 2010	$—	$—	$ 50	$ 50
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the year ended December 31, 2010	$—	$—	$ 54	$ 54

(a) Effective December 31, 2009, Exelon categorizes its NDT commingled funds within the Level 2 fair value hierarchy.
(b) Includes the reclassification of $8 million of realized losses due to settlements of derivative contracts recorded in results of operations.
(c) Excludes increases in fair value of $375 million and realized losses reclassified from OCI due to settlements of $371 million associated with Generation's financial swap contract with ComEd for the year ended December 31, 2010. The PECO block contracts were designated as normal sales as of May 31, 2010. As such, there were no effective changes in the fair value of the block contracts with PECO after that point, as the mark-to-market balances previously recorded will be amortized over the term of the contracts. The increase in fair value was $3 million through May 31, 2010. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(d) The servicing liability related to PECO's accounts receivable agreement was released in accordance with new guidance on accounting for transfers of financial assets that was adopted on January 1, 2010. See Note 10—Debt and Credit Agreements for additional information.

For the Year Ended December 31, 2009	Servicing Liability	Nuclear Decommissioning Trust Fund Investments [(e)]	Mark-to-Market Derivatives	Total
Balance as of January 1, 2009	$ (2)	$ 1,220	$ 106	$ 1,324
Total realized / unrealized gains (losses)				
Included in income	—	119	(134)[(a)]	(15)
Included in other comprehensive income	—	—	5[(b)]	5
Included in regulatory assets/liabilities	—	275	(2)	273
Change in collateral	—	—	(2)	(2)
Purchases, sales, issuances and settlements, net	—	337	—	337
Transfers out of Level 3	—	(1,951)[(c)]	(17)	(1,968)
Balance as of December 31, 2009	$ (2)	$ —	$ (44)	$ (46)
The amount of total losses included in income attributed to the change in unrealized losses related to assets and liabilities held for the year ended December 31, 2009	$—	$ —	$ (79)	$ (79)

(a) Includes the reclassification of $55 million of realized losses due to settlements of derivative contracts recorded in results of operations.

(b) Excludes $782 million of changes in the fair value and $267 million of realized losses due to settlements associated with Generation's financial swap contract with ComEd, and $2 million of changes in the fair value of Generation's block contracts with PECO. All items eliminated upon consolidation in Exelon's Consolidated Financial Statements.
(c) As of December 31, 2009, investments in NDT commingled funds, stated at NAV, were transferred out of Level 3 and into Level 2 in accordance with FASB issued authoritative guidance noted above.

The following table presents total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2010 and 2009:

	Operating Revenue	Purchased Power	Fuel	Other, net
Total gains included in income for the year ended December 31, 2010	$ 3	$ 7	$ 36	$—
Change in the unrealized gains relating to assets and liabilities held for the year ended December 31, 2010	$ 22	$ 4	$ 28	$—

	Operating Revenue	Purchased Power	Fuel	Other, net (a)
Total gains (losses) included in income for the year ended December 31, 2009	$(86)	$(11)	$(37)	$119
Change in the unrealized losses relating to assets and liabilities held for the year ended December 31, 2009	$ (2)	$ (8)	$(69)	$—

(a) Other, net activity consists of realized and unrealized gains included in income for the NDT funds held by Generation. Pursuant to the original authoritative guidance for fair value measurements, commingled funds within the NDT funds were classified in Level 3 of the fair value hierarchy. As a result of authoritative guidance issued in the third quarter of 2009 and noted above, the commingled funds were reclassified to Level 2 as of December 31, 2009.

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents. The Registrants' cash equivalents include investments with maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning. The trust fund investments have been established to satisfy Exelon's and Generation's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds. Generation's investment policies place limitations on the types and investment grade ratings of the securities that may be held by the trusts. Assets pledged for Zion Station decommissioning are not controlled by Generation and as a result, its investment activities are not subject to Generation's policies. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities, are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2.

Commingled funds, which are similar to mutual funds, are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair values of short-term commingled funds held within the trust funds, which generally hold short-term fixed income securities and are not subject to restrictions regarding the purchase or sale of shares, are derived from observable prices. The objectives of the remaining commingled funds in which Exelon and Generation invest primarily seek to track the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. In general, equity commingled funds are redeemable on the 15th of the month and the last business day of the month; however, the fund manager may designate any day as a valuation date for the purpose of purchasing or redeeming units. Effective December 31, 2009, commingled funds are categorized in Level 2 because the fair value of the funds are based on NAVs per fund share (the unit of account), primarily derived from the quoted prices in active markets on the underlying equity securities. See Note 12—Asset Retirement Obligations for further discussion on the NDT fund investments.

Rabbi Trust Investments. The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The investments in the Rabbi trusts are included in investments in the Registrants' Consolidated Balance Sheets. The fair values of the shares of the funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Mark-to-Market Derivatives. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain non-exchange-based derivatives are valued using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of non-exchange-based derivative contracts is valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For non-exchange-based derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants' non-exchange-based derivatives are predominately at liquid trading points. For non-exchange-based derivatives that trade in less liquid markets with limited pricing information, such as the financial swap contract between Generation and ComEd, model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 1, 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements. Transfers in and out of levels are recognized as of the beginning of the month the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 generally do not occur. Transfers in and out of Level 2 and Level 3 generally occur when the contract tenure becomes more observable.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon uses a calculation of future cash inflows and estimated future outflows related to the swap agreements, which are discounted and netted to determine the current fair value. Additional inputs to the present value calculation include the contract terms, counterparty credit risk and market parameters such as interest rates and volatility. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 9—Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations. The Registrants' deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants' deferred compensation obligations is based on the market value of the participants' notional investment accounts. The notional investments are comprised primarily of mutual funds, which are based on observable market prices. However, since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized in Level 2 in the fair value hierarchy.

Servicing Liability. PECO is party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in customer accounts receivables designated under the agreement in exchange for proceeds of $225 million, which PECO accounted for as a sale under previous guidance on accounting for transfers of financial assets. A servicing liability was recorded for the agreement in accordance with the applicable authoritative guidance for servicing of financial assets. The servicing liability was included in other current liabilities in Exelon's and PECO's Consolidated Balance Sheets. The fair value of the liability was determined using internal estimates based on provisions in the agreement, which were categorized as Level 3 inputs in the fair value hierarchy. The servicing liability was released in accordance with new guidance on accounting for transfers of financial assets that was adopted on January 1, 2010. See Note 10—Debt and Credit Agreements for additional information.

9. Derivative Financial Instruments

The Registrants are exposed to certain risks related to ongoing business operations. The primary risks managed by using derivative instruments are commodity price risk and interest rate risk. Exposure to interest rate risk exists as a result of the issuance of variable and fixed-rate debt, commercial paper and commitment fees under credit facilities. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, the Registrants are exposed to market fluctuations in the prices of electricity, fossil fuels, and other commodities. The Registrants employ established policies and procedures to manage their risks associated with market fluctuations by entering into physical contracts as well as financial derivative contracts including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value. Under these provisions, economic hedges are recognized on the balance sheet at their fair value unless they qualify for the normal purchases and normal sales scope exception. The Registrants have applied the normal purchases and normal sales scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. For economic hedges that qualify and are designated as cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in value of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. For economic hedges that do not qualify or are not designated as cash flow hedges, changes in the fair value of the derivative are recognized in earnings each period and are classified as other derivatives in the following tables. Non-derivative contracts for access to additional generation and for sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 18—Commitments and Contingencies. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities.

Commodity Price Risk

Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. Within Exelon, Generation has the most exposure to commodity price risk. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases, and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management's policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include financial transmission rights, whose changes in fair value are recognized in earnings each period, and auction revenue rights.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Generation hedges commodity risk on a ratable basis over three-year periods. As of December 31, 2010, the percentage of expected generation hedged was 90%-93%, 67%-70%, and 32%-35% for 2011, 2012 and 2013, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include cash flow hedges, other derivatives and certain non-derivative contracts including sales to ComEd and PECO to serve their retail load.

ComEd has locked in a fixed price for a significant portion of its commodity price risk through the five-year financial swap contract with Generation that expires on May 31, 2013, which is discussed in more detail below. In addition, the contracts that Generation has entered into with ComEd and that ComEd has entered into with Generation and other suppliers as part of the ComEd power procurement agreements, which are further discussed in Note 2—Regulatory Matters, qualify for the normal purchases and normal sales scope exception. Based on the Illinois Settlement Legislation and ICC-approved procurement methodologies permitting ComEd to recover its electricity procurement costs from retail customers with no mark-up, ComEd's price risk related to power procurement is limited.

In order to fulfill a requirement of the Illinois Settlement, Generation and ComEd entered into a five-year financial swap contract effective August 28, 2007. The financial swap is designed to hedge spot market purchases, which along with ComEd's remaining energy procurement contracts, meet its load service requirements. The remaining swap contract volumes are 3,000 MW from January 2011 through May 2013. The terms of the financial swap contract require Generation to pay the around-the-clock market price for a portion of ComEd's electricity supply requirement, while ComEd pays a fixed price. The contract is to be settled net, for the difference between the fixed and market pricing, and the financial terms only cover energy costs and do not cover capacity or ancillary services. The financial swap contract is a derivative financial instrument that has been designated by Generation as a cash flow hedge. Consequently, Generation records the fair value of the swap on its balance sheet and records changes in fair value to OCI. ComEd has not elected hedge accounting for this derivative financial instrument. ComEd records the fair value of the swap on its balance sheet, however, since the financial swap contract was deemed prudent by the Illinois Settlement Legislation, ComEd receives full cost recovery for the contract in rates and the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 2—Regulatory Matters for additional information regarding the Illinois Settlement. In Exelon's consolidated financial statements, all financial statement effects of the financial swap recorded by Generation and ComEd are eliminated.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts begins in June 2012. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability.

Prior to January 1, 2011, PECO had transferred substantially all of its commodity price risk related to its procurement of electric supply to Generation through a PPA that expired on December 31, 2010. The PPA was not considered a derivative under current derivative authoritative guidance. PECO has entered into contracts to procure electric supply through a competitive RFP process as outlined in its PAPUC-approved DSP Program, which is further discussed in Note 2—Regulatory Matters. Based on Pennsylvania legislation and the DSP Program permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk following the expiration of the electric generation rate caps through full requirements contracts and block contracts. PECO's full requirements contracts and block contracts, which are considered derivatives, qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. For block contracts designated as normal purchases after inception, the mark-to-market balances previously recorded will remain unchanged on PECO's Consolidated Balance Sheet and will be amortized over the terms of the contracts.

PECO's natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO's reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy deliverability requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO's natural gas supply and management agreements that are derivatives qualify for the normal purchases and normal sales exception. Additionally, in accordance with the 2009 and 2010 PAPUC PGC settlements and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2009 and 2010 PGC settlement, PECO is required to lock in (i.e. economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program covers 22% to 29% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into purely to profit from market price changes as opposed to hedging an exposure and is subject to limits established by Exelon's RMC. The proprietary trading activities which included physical volumes of 3,625 GWh, 7,578 GWh and 8,891 GWh for years ended December 31, 2010, 2009 and 2008, respectively, are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's revenue from energy marketing activities. Neither ComEd nor PECO enter into derivatives for proprietary trading purposes.

Interest Rate Risk

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to achieve a lower cost of capital. A hypothetical 10% increase in the interest rates associated with variable-rate debt would result in less than a $1 million decrease in Exelon's, Generation's, and ComEd's pre-tax income for the year ended December 31, 2010.

Fair Value Hedges. For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows for the year ended December 31, 2010:

	Gain (Loss) on Swaps December 31,			Gain (Loss) on Borrowings December 31,		
Income Statement Classification	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
Interest expense	$4	$(7)	$13	$(4)	$7	$(13)

At December 31, 2010 and 2009, Exelon had $100 million of notional amounts of fair value hedges outstanding related to interest rate swaps, with fair value assets of $14 million and $10 million, respectively. During the years ended December 31, 2010 and 2009, there was no impact on the results of operations as a result of ineffectiveness from fair value hedges.

Cash Flow Hedges. On September 30, 2010, Generation issued and sold $350 million of senior notes due October 1, 2041. In connection with this debt issuance, Generation entered into treasury rate locks in the aggregate notional amount of $240 million. The treasury rate locks were settled on September 27, 2010. Treasury rate locks are derivative instruments used to lock in the interest rate prior to the issuance of debt. As a result of a decrease in interest rates during the period between the inception and settlement of the treasury rate locks, Generation recorded a pre-tax loss of approximately $4 million. The loss was recorded to other comprehensive income within Generation's Consolidated Balance Sheets and will be amortized as an increase to interest expense over the life of the related debt as interest payments are made on the debt.

In connection with Generation's September 2009 $1.5 billion debt issuance, Generation entered into forward-starting interest rate swaps in the aggregate notional amount of $1.1 billion. The interest rate swaps were settled on September 16, 2009 with Generation recording a $7 million pre-tax gain. The gain was recorded to OCI within Generation's Consolidated Balance Sheets and is amortized to income over the life of the related debt as a reduction in interest expense.

In connection with its August 2, 2010 issuance of First Mortgage Bonds, ComEd entered into treasury rate locks in the aggregate notional amount of $350 million. The treasury rate locks were settled on July 27, 2010. As interest rates decreased since the inception of the treasury rate locks, ComEd recorded a pre-tax loss of approximately $4 million. Under the authoritative accounting guidance for regulated operations, the loss was recorded as a regulatory asset within ComEd's Consolidated Balance Sheets at settlement and will be amortized as an increase to interest expense over the life of the related debt as interest payments are made on the debt.

Other Derivatives. On September 30, 2010, Generation issued and sold $550 million of 10-year Senior Notes. In connection with this debt issuance, Generation entered into treasury rate locks in the aggregate notional amount of approximately $360 million. As a result of a decrease in interest rates during the period between the inception and settlement of the treasury rate locks, Generation recorded a pre-tax loss of approximately $5 million. The debt associated with these treasury rate locks, which was used to fund a portion of the Exelon Wind acquisition, was subject to a mandatory redemption provision in the event the acquisition was not consummated on or prior to March 31, 2011. As a result, these treasury rate locks did not qualify for cash flow hedge accounting treatment and the associated loss was recorded to interest expense within Generation's Consolidated Income Statements. See Note 10—Debt and Credit Agreements for additional information on the redemption provision of this debt issuance.

Fair Value Measurement

Fair value accounting guidance requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. In the table below, Generation's cash flow hedges, other derivatives and proprietary trading derivatives are shown gross and the impact of the netting of fair value balances with the same counterparty, as well as netting of collateral, is aggregated in the collateral and netting column. Excluded from the tables below are economic hedges that qualify for the normal purchases and normal sales exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2010:

	Generation					ComEd	PECO	Other		Exelon
Derivatives	Cash Flow Hedges (a)(d)	Other Derivatives	Proprietary Trading	Collateral and Netting (b)	Subtotal (c)	Other Derivatives (a)(e)	Other Derivatives (d)	Other Derivatives	Intercompany Elimination (a)(d)	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 532	$1,203	$ 225	$(1,473)	$ 487	$ —	$—	$—	$ —	$487
Mark-to-market derivative assets with affiliate (current assets)	455	—	—	—	455	—	—	—	(455)	—
Mark-to-market derivative assets (noncurrent assets)	204	547	56	(416)	391	4	—	14	—	409
Mark-to-market derivative assets with affiliate (noncurrent assets)	525	—	—	—	525	—	—	—	(525)	—
Total mark-to-market derivative assets	$1,716	$1,750	$ 281	$(1,889)	$1,858	$ 4	$—	$ 14	$(980)	$896
Mark-to-market derivative liabilities (current liabilities)	$ (21)	$ (551)	$(200)	$ 738	$ (34)	$ —	(4)	$—	$ —	$ (38)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	—	(450)	(5)	—	455	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(24)	(143)	(54)	200	(21)	—	—	—	—	(21)
Mark-to-market derivative liabilities with affiliate (noncurrent liabilities)	—	—	—	—	—	(525)	—	—	525	—
Total mark-to-market derivative liabilities	(45)	(694)	(254)	938	(55)	(975)	(9)	—	980	(59)
Total mark-to-market derivative net assets (liabilities)	$1,671	$1,056	$ 27	$ (951)	$1,803	$(971)	$ (9)	$ 14	$ —	$837

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $450 million and $525 million, respectively, related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above.
(b) Represents the netting of fair value balances with the same counterparty and the application of collateral.

(c) Current and noncurrent assets are shown net of collateral of $725 million and $199 million, respectively, and current and noncurrent liabilities are shown inclusive of collateral of $10 million and $17 million, respectively. The total cash collateral received net of cash collateral posted and offset against mark-to-market assets and liabilities was $951 million at December 31, 2010.
(d) Includes current assets for Generation and current liabilities for PECO of $5 million related to the fair value of PECO's block contracts with Generation. There were no netting adjustments or collateral received as of December 31, 2010. The PECO block contracts were designated as normal as of May 31, 2010. As such, there were no effective changes in fair value of PECO's block contracts for the remainder of 2010 as the mark-to-market balances previously recorded will be amortized over the term of the contract.
(e) Includes noncurrent assets relating to floating-to-fixed energy swap contracts with unaffiliated suppliers recorded in other deferred debits and other assets on ComEd's Consolidated Balance Sheets.

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2009:

	Generation					ComEd	PECO	Other		Exelon
Derivatives	**Cash Flow Hedges (a)**	**Other Derivatives**	**Proprietary Trading**	**Collateral and Netting (b)**	**Subtotal (c)**	**Other Derivatives (a)**	**Other Derivatives (d)**	**Other Derivatives**	**Intercompany Eliminations (a)(d)**	**Total Derivatives**
Mark-to-market derivative assets (current assets)	$ 576	$ 913	$ 193	$(1,306)	$ 376	$ —	$—	$—	$ —	$ 376
Mark-to-market derivative assets with affiliate (current assets)	302	—	—	—	302	—	—	—	(302)	—
Mark-to-market derivative assets (noncurrent assets)	423	792	102	(678)	639	—	—	10	—	649
Mark-to-market derivative assets with affiliate (noncurrent assets)	671	—	—	—	671	—	—	—	(671)	—
Total mark-to-market derivative assets	$1,972	$1,705	$ 295	$(1,984)	$1,988	$ —	$—	$ 10	$(973)	$1,025
Mark-to-market derivative liabilities (current liabilities)	$ (18)	$ (743)	$(172)	$ 735	$ (198)	$ —	$—	$—	$ —	$ (198)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	—	(302)	—	—	302	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(42)	(183)	(98)	302	(21)	—	(2)	—	—	(23)
Mark-to-market derivative liability with affiliate (noncurrent liabilities)	—	—	—	—	—	(669)	(2)	—	671	—
Total mark-to-market derivative liabilities	(60)	(926)	(270)	1,037	(219)	(971)	(4)	—	973	(221)
Total mark-to-market derivative net assets (liabilities)	$1,912	$ 779	$ 25	$ (947)	$1,769	$(971)	$ (4)	$ 10	$ —	$ 804

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $302 million and $669 million, respectively, related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above.
(b) Represents the netting of fair value balances with the same counterparty and the application of collateral.
(c) Current and noncurrent assets are shown net of collateral of $502 million and $376 million, respectively, and current liabilities are shown inclusive of collateral of $69 million, respectively. The allocation of collateral had no impact to noncurrent liabilities. The total cash collateral received net of cash collateral posted and offset against mark-to-market assets and liabilities was $947 million at December 31, 2009.
(d) Includes a noncurrent asset for Generation and a noncurrent liability for PECO of $2 million related to the fair value of PECO's block contracts with Generation. There were no netting adjustments or collateral received as of December 31, 2009.

Cash Flow Hedges. Economic hedges that qualify as cash flow hedges primarily consist of forward power sales and power swaps on base load generation. At December 31, 2010, Generation had net unrealized pre-tax gains on effective cash flow hedges of $ 1,670 million being deferred within accumulated OCI, including approximately $975 million related to the financial swap with ComEd. Amounts recorded in accumulated OCI related to changes in energy commodity cash flow hedges are reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs. Reclassifications from OCI are included in operating revenues, purchased power and fuel in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income, depending on the commodities involved in the hedged transaction. Based on market prices at December 31, 2010, approximately $966 million of these net pre-tax unrealized gains within accumulated OCI are expected to be reclassified from accumulated OCI during the next twelve months by Generation, including approximately $450 million related to the financial swap with ComEd and $5 million related to PECO's block contracts with Generation. However, the actual amount reclassified from accumulated OCI could vary due to future changes in market prices. Generation expects the settlement of the majority of its cash flow hedges, including the ComEd financial swap contract, will occur during 2011 through 2013.

Exelon discontinues hedge accounting prospectively when it determines that the derivative is no longer effective in offsetting changes in the cash flows of a hedged item, in the case of forward-starting hedges, or when it is no longer probable that the forecasted transaction will occur. For the year ended December 31, 2010, amounts reclassified into earnings as a result of the discontinuance of cash flow hedges were immaterial.

The table below provides the activity of accumulated OCI related to cash flow hedges for the years ended December 31, 2010 and 2009, containing information about the changes in the fair value of cash flow hedges and the reclassification from accumulated OCI into results of operations. The amounts reclassified from accumulated OCI, when combined with the impacts of the actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
	Income Statement Location	Energy Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at January 1, 2009		$ 855[(a)]	$ 563
Effective portion of changes in fair value		1,227[(b)]	757
Reclassifications from accumulated OCI to net income	Operating Revenue	(939)[(c)]	(778)
Ineffective portion recognized in income	Purchased Power	9	9
Accumulated OCI derivative gain at December 31, 2009		$1,152[(a)(d)]	$ 551
Effective portion of changes in fair value		541[(b)]	304[(e)]
Reclassifications from accumulated OCI to net income	Operating Revenue	(681)[(c)]	(454)[(f)]
Ineffective portion recognized in income	Purchased Power	(1)	(1)
Accumulated OCI derivative gain at December 31, 2010		$1,011[(a)(d)]	$ 400

(a) Includes $589 million, $585 million and $275 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd for the years ended December 31, 2010, 2009 and 2008, respectively, and $3 million and $1 million of gains, net of taxes, related to the fair value of the block contracts with PECO for the years ended December 31, 2010 and 2009, respectively.

(b) Includes $228 million and $471 million of gains, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd for the years ended December 31, 2010 and 2009, respectively, and $2 million and $1 million of gains, net of taxes, of the effective portion of changes in fair value of the block contracts with PECO for the year ended December 31, 2010 and 2009, respectively. The PECO block contracts were designated as normal sales as of May 31, 2010. As such, there were no effective changes in fair value of the block contracts with PECO for the remainder of 2010 as the mark-to-market balances previously recorded will be amortized over the terms of the contracts.

(c) Includes $224 million and $161 million losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the years ended December 31, 2010 and 2009, respectively.

(d) Excludes $2 million of gains, net of taxes, related to interest rate swaps and treasury rate locks for the year ended December 31, 2010 and $5 million of gains, net of taxes, related to interest rate swaps for the year ended 2009. See Note 10—Debt and Credit Agreements for further information.

(e) Includes $3 million of losses, net of taxes, related to the effective portion of changes in fair value of treasury rate locks at Generation and ComEd, respectively.

(f) Reflects the reclassifications of $4 million to regulatory assets and $1 million to deferred income tax liabilities within Exelon's and ComEd's Consolidated Balance Sheets associated with settled treasury rate locks at ComEd.

During the years ended December 31, 2010, 2009 and 2008, Generation's cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $1,125 million and $1,559 million pre-tax gain, and a $544 million pre-tax loss, respectively. Given that the cash flow hedges primarily consist of forward power sales and power swaps and do not include gas options or sales, the ineffectiveness of Generation's cash flow hedges is primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units. This price difference is actively managed through other instruments which include financial transmission rights, whose changes in fair value are recognized in earnings each period, and auction revenue rights. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices, were $1 million, $15 million and $44 million for the years ended December 31, 2010, 2009, and 2008, respectively, none of which was related to Generation's financial swap contract with ComEd or Generation's block contracts with PECO. At December 31, 2010, cash flow hedge ineffectiveness resulted in an adjustment of $1 million to accumulated OCI on the balance sheet in order to reflect the effective portion of derivative gains or losses. At December 31, 2009, cash flow hedge ineffectiveness was not significant.

Exelon's energy related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $754 million and $1,292 million pre-tax gain and a $521 million pre-tax loss for the years ended December 31, 2010, 2009 and 2008, respectively. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices, were $1 million, $15 million and $44 million for the years ended December 31, 2010, 2009 and 2008, respectively. At December 31, 2010, cash flow hedge ineffectiveness resulted in an adjustment of $1 million to accumulated OCI on the balance sheet in order to reflect the effective portion of derivative gains or losses. At December 31, 2009, cash flow hedge ineffectiveness was not significant.

Other Derivatives. Other derivative contracts are those that do not qualify or are not designated for hedge accounting. These instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, and forward sales. For the years ended December 31, 2010, 2009 and 2008, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in fuel and purchased power expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

For the Year Ended December 31, 2010	Purchased Power	Fuel	Total
Change in fair value	$ 288	$ 101	$ 389
Reclassification to realized at settlement	(292)	(12)	(304)
Net mark-to-market gains (losses)	$ (4)	$ 89	$ 85

For the Year Ended December 31, 2009	Purchased Power	Fuel	Total
Change in fair value	$ 206	$ (72)	$ 134
Reclassification to realized at settlement	(97)	159	62
Net mark-to-market gains	$ 109	$ 87	$ 196

For the Year Ended December 31, 2008	Purchased Power	Fuel	Total
Change in fair value	$315	$ 180	$495
Reclassification to realized at settlement	55	(143)	(88)
Net mark-to-market gains	$370	$ 37	$407

Proprietary Trading Activities. For the years ended December 31, 2010, 2009 and 2008, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity on derivative instruments entered into for proprietary trading purposes. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

		For the Year Ended December 31,		
	Location on Income Statement	2010	2009	2008
Change in fair value	Operating Revenue	$ 26	$ 3	$106
Reclassification to realized at settlement	Operating Revenue	(24)	(86)	(43)
Net mark-to-market gains (losses)	Operating Revenue	$ 2	$(83)	$ 63

Credit Risk

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross-product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation's credit exposure for all derivative instruments, which includes contracts that qualify for the normal purchases and normal sales exception, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2010. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the maturity of a company's credit risk by credit rating of the counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs and NYMEX and ICE commodity exchanges, which are discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd and PECO of $58 million and $248 million, respectively. See Note 21—Related-Party Transactions for further information.

Rating as of December 31, 2010	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$1,495	$563	$932	1	$102
Non-investment grade	9	3	6	—	—
No external ratings					
Internally rated—investment grade	42	5	37	—	—
Internally rated—non-investment grade	1	1	—	—	—
Total	$1,547	$572	$975	1	$102

Net Credit Exposure by Type of Counterparty	December 31, 2010
Financial institutions	$280
Investor-owned utilities, marketers and power producers	515
Other	180
Total	$975

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of December 31, 2010, ComEd's credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 2—Regulatory Matters for further information.

PECO's supplier master agreements that govern the terms of its DSP program contracts and define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from S&P, Fitch or Moody's and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2010, PECO's net credit exposure to suppliers was immaterial and did not exceed the allowed unsecured credit levels.

PECO is permitted to recover its costs of procuring electric generation after December 31, 2010, through its PAPUC-approved DSP program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 2—Regulatory Matters for further information.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and management agreements. As of December 31, 2010, PECO had credit exposure of $10 million under its natural gas supply and management agreements.

Collateral and Contingent-Related Features (Exelon, Generation, ComEd, and PECO)

As part of the normal course of business, Generation routinely enters into physical and financial contracts for the purchase and sale of electricity, fossil fuels, and other commodities. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. Generation also enters into commodity transactions on NYMEX and ICE. The NYMEX and ICE clearing houses act as the counterparty to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margining requirements.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on NYMEX and ICE that are fully collateralized) was $742 million and $894 million as of December 31, 2010 and December 31, 2009, respectively. As of December 31, 2010 and 2009, Generation had the contractual right of offset of $717 million and $778 million, respectively, related to derivative instruments that are assets with the same counterparty under master netting agreements, resulting in a net liability position of $25 million and $116 million, respectively. If Generation had been downgraded to the investment grade rating of BBB- and Baa3, or lost its investment grade credit rating, it would have been required to provide incremental collateral of approximately $57 million or $944 million, respectively, as of December 31, 2010 and approximately $60 million or $673 million, respectively, as of December 31, 2009 related to its financial instruments, including derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements and the application of collateral. See Note 18—Commitments and Contingencies for information regarding the letters of credit supporting the cash collateral.

Generation entered into SFCs with certain utilities, including PECO, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of the financial swap contract between Generation and ComEd, if a party is downgraded below investment grade by Moody's or S&P, collateral postings would be required by that party depending on how market prices compare to the benchmark price levels. Under the terms of the financial swap contract, collateral postings will never exceed $200 million from either ComEd or Generation. Beginning in June 2009, under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of December 31, 2010, there was no cash collateral or letters of credit posted between energy suppliers, including Generation, and ComEd, under any of the above-mentioned contracts. As of December 31, 2010, ComEd did not hold any cash or letters of credit for the purpose of collateral from any of the suppliers in association with energy procurement contracts. Beginning in June 2010, under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, beginning in December 2010, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both

RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of December 31, 2010, ComEd held approximately $20 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 2—Regulatory Matters for further information.

PECO's supplier master agreements that govern the terms of its DSP program contracts do not contain provisions that would require PECO to post collateral.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from Moody's and S&P. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2010, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2010, PECO could have been required to post approximately $68 million of collateral to its counterparties.

Exelon's interest rate swaps contain provisions that, in the event of a merger, require that Exelon's debt maintain an investment grade credit rating from Moody's or S&P. If Exelon's debt were to fall below investment grade, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty. The settlement amount would be equal to the fair value of the swap on the termination date. As of December 31, 2010, Exelon's interest rate swap was in an asset position, with a fair value of $14 million.

Accounting for the Offsetting of Amounts Related to Certain Contracts

As of December 31, 2010 and 2009, $1 million and $6 million, respectively, of cash collateral received was not offset against net derivative positions, as they were not associated with energy-related derivatives.

10. Debt and Credit Agreements

Short-Term Borrowings

Exelon meets its short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. ComEd meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility.

Exelon, Generation, ComEd and PECO had the following amounts of commercial paper and credit facility borrowings outstanding at December 31, 2010 and 2009:

Commercial Paper Issuer	Maximum Program Size at December 31, 2010 (a)	Maximum Program Size at December 31, 2009 (a)	Outstanding Commercial Paper at December 31, 2010	Outstanding Commercial Paper at December 31, 2009	Average Interest Rate on Commercial Paper Borrowings for the year ended December 31, 2010	Average Interest Rate on Commercial Paper Borrowings for the year ended December 31, 2009
Exelon Corporate	$ 957	$ 957	$—	$—	—	0.72%
Generation	4,834	4,834	—	—	—	—
ComEd	1,000	952	—	—	0.74%	—
PECO	574	574	—	—	—	0.67%
Total	$7,365	$7,317	$—	$—	0.74%	0.71%

(a) Equals aggregate bank commitments under revolving credit agreements. See discussion below and Credit Agreements table below for items affecting effective program size.

Credit facility borrowings	December 31, 2010	December 31, 2009
ComEd	$—	$155

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have revolving credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its commercial paper outstanding does not reduce available capacity under a Registrant's credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the available capacity under its credit agreement.

The following tables present the short-term borrowings activity for Exelon during 2010, 2009 and 2008:

Exelon

	2010	2009	2008
Average borrowings	$ 125	$ 132	$ 636
Maximum borrowings outstanding	346	523	1,646
Average interest rates, computed on a daily basis	0.72%	0.73%	3.22%
Average interest rates, at December 31	n.a.	0.69%	0.93%

n.a. Not applicable.

Credit Agreements

As of December 31, 2010, Exelon Corporate, Generation and PECO had access to separate unsecured credit facilities with aggregate bank commitments of $957 million, $4.8 billion and $574 million, respectively. The credit agreements expire on October 26, 2012, unless extended in accordance with their terms. Under their credit facilities, Exelon Corporate, Generation and PECO may request additional one-year extensions of that term. In addition, Exelon Corporate, Generation and PECO may request increases in the aggregate bank commitments under their credit facilities up to an additional $250 million, $1 billion and $200 million, respectively. Exelon anticipates refinancing these credit facilities in the first half of 2011.

On March 25, 2010, ComEd replaced its $952 million credit facility with a new three-year $1 billion unsecured revolving credit facility that expires March 25, 2013, unless extended in accordance with its terms. ComEd may request additional one-year extensions of that term. In addition, ComEd may request increases in the aggregate bank commitments under its credit facility up to an additional $500 million. Any such extensions or increases are subject to the approval of the lenders party to the credit facility.

The Registrants may use the credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. The obligation of each lender to make any credit extension to a Registrant under its credit facilities is subject to various conditions including, among other things, that no event of default has occurred for the Registrant or would result from such credit extension. An event of default under any of the Registrants' credit facilities would not constitute an event of default under any of the other Registrants' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation under its credit facility would constitute an event of default under the Exelon corporate credit facility.

At December 31, 2010, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under the credit agreements:

				Available Capacity at December 31, 2010		Average Interest Rate on Facility Borrowings for the year ended December 31, 2010
Borrower	**Aggregate Bank Commitment (a)**	**Facility Draws**	**Outstanding Letters of Credit**	**Actual**	**To Support Additional Commercial Paper**	
Exelon Corporate	$ 957	$—	$ 7	$ 950	$ 950	—
Generation	4,834	—	214	4,620	4,620	—
ComEd	1,000	—	196	804	804	0.61%
PECO	574	—	1	573	573	—
Total	$7,365	$—	$418	$6,947	$6,947	—

(a) Excludes additional credit facility agreements for Generation, ComEd and PECO with aggregate commitments of $30 million, $32 million and $32 million, respectively, arranged with minority and community banks located primarily within ComEd's and PECO's service territories. These facilities expire on October 21, 2011 and are solely for issuing letters of credit. As of December 31, 2010, letters of credit issued under these agreements totaled $11 million, $26 million and $20 million for Generation, ComEd and PECO, respectively.

Borrowings under each credit agreement bear interest at a rate selected by the borrower based upon either the prime rate or at a rate fixed for a specified period based upon a LIBOR-based rate. The Exelon, Generation and PECO agreements provide for an adder of up to 65 basis points to be added to the LIBOR-based rate, based upon the credit rating of the borrower. The ComEd agreement provides for adders of up to 137.5 basis points for prime-based borrowings and 237.5 basis points for LIBOR-based borrowings to be added, based upon ComEd's credit rating.

Additionally, on November 4, 2010, Generation entered into a supplemental credit facility, which provides for an aggregate commitment of up to $300 million. The effectiveness and availability of the credit facility were subject to various conditions, which were satisfied on February 7, 2011. This facility will be primarily used to issue letters of credit, but also permits cash borrowings at a rate of LIBOR or a base rate, plus an adder of 200 basis points. No cash borrowings are anticipated under this facility.

Each credit agreement requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The ratios exclude revenues and interest expenses attributable to securitization debt, certain changes in working capital, distributions on preferred securities of subsidiaries and, in the case of Exelon and Generation, interest on the debt of its project subsidiaries. The following table summarizes the minimum thresholds reflected in the credit agreements for the year ended December 31, 2010:

	Exelon	Generation	ComEd	PECO
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1

At December 31, 2010 the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO
Interest coverage ratio	12.42	27.46	5.34	4.68

Variable Rate Debt

Under the terms of ComEd's variable-rate tax-exempt debt agreements, ComEd may be required to repurchase that debt before its stated maturity unless supported by sufficient letters of credit. If ComEd was required to repurchase the debt, it would reassess its options to obtain new letters of credit or remarket the bonds in a manner that does not require letter of credit support. ComEd has classified certain amounts outstanding under these debt agreements as long-term based on management's intent and ability to renew or replace the letters of credit, refinance the debt at reasonable terms on a long-term fixed-rate basis or utilize the capacity under existing long-term credit facilities.

Generation had letter of credit facilities that expired during the second quarter of 2010, which were used to enhance the credit of variable-rate long-term tax-exempt bonds totaling $213 million, with maturities ranging from 2016—2034. Generation repurchased the $213 million of tax-exempt bonds during 2010 and permanently extinguished $24 million of these tax-exempt bonds. Generation has the ability to remarket the remaining bonds whenever it determines it to be economically advantageous.

Accounts Receivable Agreement

PECO is party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its customer accounts receivable designated under the agreement in exchange for proceeds of $225 million, which Exelon and PECO accounted for as a sale under previous guidance on accounting for transfers of financial assets. The accounting guidance was amended, effective for the Registrants on January 1, 2010, and required that this transaction be accounted for as a secured borrowing, as the transferred interest did not meet the criteria of a participating interest as defined under the authoritative guidance. Therefore, on January 1, 2010, the proceeds of $225 million representing the transferred interest in customer accounts receivable previously recorded as a contra-receivable were reclassified to a short-term note payable on Exelon's and PECO's Consolidated

Balance Sheets. Additionally, the servicing liability of $2 million recorded under the previous guidance was released. As of December 31, 2010, the financial institution's undivided interest in Exelon's and PECO's gross customer accounts receivable was equivalent to $346 million, which is calculated under the terms of the agreement. Upon termination or liquidation of this agreement, the financial institution will be entitled to recover up to $225 million plus the accrued yield payable from the pool of receivables pledged. On September 7, 2010, PECO extended this agreement, which terminates on September 6, 2011 unless further extended in accordance with its terms. As of December 31, 2010, PECO was in compliance with the requirements of the agreement. In the event the agreement is not further extended, PECO has sufficient short-term liquidity and could seek alternative financing.

Long-Term Debt

The following tables present the outstanding long-term debt at Exelon as of December 31, 2010 and 2009:

	Rates	Maturity Date	December 31, 2010	December 31, 2009
Long-term debt				
First mortgage bonds [a][b]:				
Fixed rates	4.00%-7.63%	2011-2038	$ 6,917	$ 6,630
Floating rates	0.24%-0.27%	2017-2021	191	191
Senior unsecured notes	4.00%-6.25%	2014-2041	4,902	4,400
Notes payable and other [c]	6.95%-7.83%	2011-2020	176	178
Pollution control notes:				
Floating rates	0.29%-0.35%	2016-2034	—	213
Fixed rates	5.00%	2042	46	46
Sinking fund debentures	4.75%	2011	2	2
Total long-term debt			12,234	11,660
Unamortized debt discount and premium, net			(34)	(35)
Unamortized settled fair value hedge, net			(1)	(1)
Fair value hedge carrying value adjustment, net			14	10
Long-term debt due within one year			(599)	(639)
Long-term debt			$11,614	$10,995
Long-term debt to financing trusts [d]				
Payable to PETT	6.52%	2010	—	415
Subordinated debentures to ComEd Financing III	6.35%	2033	206	206
Subordinated debentures to PECO Trust III	7.38%	2028	81	81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Total long-term debt to financing trusts			390	805
Long-term debt due to financing trusts due within one year			—	(415)
Long-term debt to financing trusts			$ 390	$ 390

(a) Substantially all of ComEd's assets other than expressly excepted property and substantially all of PECO's assets are subject to the liens of their respective mortgage indentures.
(b) Includes First Mortgage Bonds issued under the ComEd and PECO mortgage indentures securing pollution control bonds and notes.
(c) Includes capital lease obligations of $36 million and $38 million at December 31, 2010 and 2009, respectively. Lease payments of $2 million, $3 million, $3 million, $3 million, $3 million and $21 million will be made in 2011, 2012, 2013, 2014, 2015 and thereafter, respectively.
(d) Amounts owed to these financing trusts are recorded as debt to financing trusts within Exelon's Consolidated Balance Sheets.

On January 18, 2011, ComEd issued $600 million of 1.625% First Mortgage Bonds, Series 110, due January 15, 2014. The net proceeds of the Bonds were used by ComEd as an interim source of liquidity for the January 2011 contribution to Exelon-sponsored pension plans in which ComEd participates. ComEd anticipates receiving tax refunds as a result of both the pension contribution and recent Federal tax legislation allowing for accelerated depreciation deductions in 2011 and 2012. As a result, the immediate and direct use of the net proceeds to fund the planned contribution will allow those future cash receipts to be available to ComEd to fund capital investment and for general corporate purposes. See Note 13—Retirement Benefits for further discussion of the anticipated pension contribution.

Long-term debt maturities at Exelon in the periods 2011 through 2015 and thereafter are as follows:

Year	
2011	$ 599
2012	828
2013	555
2014	770
2015	1,063
Thereafter	8,809[(a)]
Total	$12,624

(a) Includes $390 million due to ComEd and PECO financing trusts.

See Note 4—Accounts Receivable for information regarding PECO's accounts receivable agreement.

See Note 9—Derivative Financial Instruments for additional information regarding interest rate swaps.

See Note 15—Preferred Securities for additional information regarding preferred securities.

11. Income Taxes

Income tax expense (benefit) from continuing operations is comprised of the following components:

	For the Year Ended December 31,		
	2010	2009	2008
Included in operations:			
Federal			
Current	$ 506	$ 803	$ 790
Deferred	972	775	341
Investment tax credit amortization	(12)	(12)	(12)
State			
Current	171	154	169
Deferred	21	(8)	29
Total	$1,658	$1,712	$1,317

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

	For the Year Ended December 31,		
	2010	2009	2008
U.S. Federal statutory rate	35.0%	35.0%	35.0%
Increase (decrease) due to:			
State income taxes, net of Federal income tax benefit	3.0	2.1	3.2
Qualified nuclear decommissioning trust fund income (losses)	1.7	3.1	(3.2)
Domestic production activities deduction	(1.2)	(0.9)	(1.3)
Tax exempt income	(0.1)	(0.1)	(0.2)
Health care reform legislation	1.4	—	—
Amortization of investment tax credit	(0.3)	(0.2)	(0.2)
Nontaxable postretirement benefits	—	(0.2)	(0.3)
Other	(0.2)	—	(0.4)
Effective income tax rate	39.3%	38.8%	32.6%

The tax effects of temporary differences, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2010 and 2009 are presented below:

	For the Year Ended December 31,	
	2010	2009
Plant basis differences	$(5,931)	$(5,838)
Stranded cost recovery	—	(567)
Unrealized gains on derivative financial instruments	(523)	(613)
Deferred pension and post-retirement obligation	485	1,312
Emission allowances	—	(24)
Nuclear decommissioning activities	(444)	(334)
Deferred debt refinancing costs	(46)	(59)
Goodwill	4	4
Other, net	(39)	441
Deferred income tax liabilities (net)	$(6,494)	$(5,678)
Unamortized investment tax credits	(212)	(224)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(6,706)	$(5,902)

The following table provides Exelon's carryforwards and any corresponding valuation allowances as of December 31, 2010.

As of December 31, 2010	
State net operating loss carryforward	$539[a]
Deferred taxes	20
Valuation allowance	9

(a) Exelon's state net operating loss carryforwards will expire beginning in 2019.

Tabular reconciliation of unrecognized tax benefits

The following table provides a reconciliation of Exelon's unrecognized tax benefits as of December 31, 2010, 2009 and 2008:

	2010	2009	2008
Unrecognized tax benefits at beginning of year	$1,498	$1,495	$1,582
Increases based on tax positions related to current year	1	—	3
Decreases based on tax positions related to current year	(2)	(2)	—
Change to positions that only affect timing	(262)	19	(74)
Increases based on tax positions prior to current year	8	4	18
Decreases based on tax positions prior to current year	(3)	—	—
Decreases related to settlements with taxing authorities	(452)	(18)	(25)
Decreases from expiration of statute of limitations	(1)	—	(9)
Unrecognized tax benefits at end of year	$ 787	$1,498	$1,495

Included in Exelon's unrecognized tax benefits balance at December 31, 2010 and 2009 are approximately $783 million and $1.4 billion, respectively, of tax positions for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits. The disallowance of such positions would not materially affect the annual effective tax rate but would accelerate the payment of cash to or defer the receipt of the cash tax benefit from the taxing authority to an earlier or later period respectively.

Unrecognized tax benefits that if recognized would affect the effective tax rate

Exelon and Generation have $4 million and $4 million, respectively, of unrecognized tax benefits at December 31, 2010 that, if recognized, would decrease the effective tax rate. Exelon, Generation and ComEd had $95 million, $33 million and $62 million, respectively, of unrecognized tax benefits at December 31, 2009 that, if recognized, would decrease the effective tax rate.

Total amounts of interest and penalties recognized

Exelon, Generation, ComEd and PECO have reflected in their Consolidated Balance Sheets as of December 31, 2010 a net interest receivable (payable) of $21 million, $(22) million, $14 million and $22 million, respectively, related to their uncertain tax positions. Exelon, Generation, ComEd and PECO reflected in their Consolidated Balance Sheets as of December 31, 2009 a net interest receivable (payable) of $28 million, $(17) million, $(28) million and $54 million, respectively, related to their uncertain tax positions. The Registrants recognize accrued interest related to uncertain tax positions in interest expense (income) in other income and deductions on their Consolidated Statements of Operations and Comprehensive Income. Exelon, Generation, ComEd and PECO have reflected in their Consolidated Statements of Operations and Comprehensive Income net interest expense of $110 million, $6 million, $57 million and $35 million, respectively, related to their uncertain tax positions for the twelve months ended December 31, 2010. For the twelve months ended December 31, 2009, Exelon, Generation, ComEd and PECO reflected in their Consolidated Statements of Operations and Comprehensive Income net interest expense (income) of $(42) million, $9 million, $(62) million and $(5) million, respectively, related to their uncertain tax positions. For the twelve months ended December 31, 2008, Exelon, Generation, ComEd and PECO reflected in their Consolidated Statements of Operations and Comprehensive Income net interest expense (income) of $(31) million, $(11) million, $(2) million and $(12) million, respectively, related to their uncertain tax positions. The Registrants have not accrued any penalties with respect to uncertain tax positions.

Reasonably possible that total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Nuclear Decommissioning Liabilities

AmerGen filed income tax refund claims taking the position that nuclear decommissioning liabilities assumed as part of its acquisition of nuclear power plants are taken into account in determining the tax basis in the assets it acquired. The additional basis results primarily in reduced capital gains or increased capital losses on the sale of assets in nonqualified decommissioning funds and increased tax depreciation and amortization deductions. The IRS disagrees with this position and has disallowed the claims. In November of 2008, Generation received a final determination from the Appeals division of the IRS (IRS Appeals) disallowing AmerGen's refund claims. On February 20, 2009, Generation filed a complaint in the United States Court of Federal Claims to contest this determination. In August 2009, the United States Department of Justice (DOJ) filed its answer denying the allegations made by Generation in its complaint. No trial date has yet been assigned, but trial could occur sometime in 2012.

The trial judge assigned to the case has noted the availability of the court's Alternative Dispute Resolution (ADR) program as an alternative to a trial, but the parties have not yet met with the ADR judge. The ADR program is a non-binding process that utilizes a variety of techniques such as mediation, neutral evaluation, and non-binding arbitration that allow the parties to better understand their differences and their prospects for settlement. The DOJ presently refuses to commit to participate in ADR. As a result, it is unclear whether ADR will occur and if so, when.

In addition, in the second quarter of 2010, Entergy Corporation concluded its trial in the United States Tax Court of a similar dispute involving the assumption of decommissioning liabilities in connection with the purchase of a nuclear power plant. It is possible that a decision will be reached in that case in the next twelve months. While the decision in that case would not serve as binding precedent for AmerGen's litigation in the United States Court of Federal Claims, the reasoning of the decision may cause Generation to reevaluate the total amount of unrecognized tax benefits. Due to the possibility of quicker resolution through the ADR program and the possibility of a decision being entered in the Entergy trial, Generation believes that it is reasonably possible that the total amount of unrecognized tax benefits may significantly decrease in the next twelve months.

Tax Method of Accounting for Repairs

In 2009, Exelon received approval from the IRS to change its method of accounting for repair costs associated with Generation's power plants. The new tax method of accounting resulted in net positive cash flow for 2010 of approximately $160 million and approximately $420 million for 2009. Although the IRS granted Exelon approval to change its method of accounting, the approval did not affirm the methodology used to calculate the deduction. Exelon had requested and received approval from the IRS to review its methodology through its Pre-Filing Agreement program. However, in the second quarter of 2010, Exelon was informed that the IRS has suspended the pre-filing agreement process and instead intends to issue broad industry guidance with respect to electric generation power plants. If that broader guidance is issued, it is reasonably possible that the total amount of unrecognized tax benefits could increase or decrease within the next 12 months.

See 1999 Sale of Fossil Generating Assets in Other Tax Matters section below for information regarding the amount of unrecognized tax benefits associated with this matter that could change significantly within the next 12 months.

See Competitive Transition Charges in Other Tax Matters section below for information regarding the amount of unrecognized tax benefits associated with this matter that could change significantly within the next 12 months.

Description of tax years that remain subject to examination by major jurisdiction

Taxpayer	Open Years
Exelon (and predecessors) and subsidiaries consolidated Federal income tax returns	1999-2009
Exelon and subsidiaries Illinois unitary income tax returns	2004-2009
Exelon Pennsylvania corporate net income tax returns	2006-2009
PECO Pennsylvania corporate net income tax returns	2007-2009

The audit of Exelon's 2002 through 2006 taxable years was completed in the first quarter of 2010.

Other Tax Matters

IRS Appeals 1999-2001

1999 Sale of Fossil Generating Assets. Exelon, through its ComEd subsidiary, took two positions on its 1999 income tax return to defer approximately $2.8 billion of tax gain on the 1999 sale of ComEd's fossil generating assets. Exelon deferred approximately $1.6 billion of the gain under the involuntary conversion provisions of the IRC. Exelon believes that it was economically compelled to dispose of ComEd's fossil generating plants as a result of the Illinois Act and that the proceeds from the sale of the fossil plants were properly reinvested in qualifying replacement property such that the gain could be deferred over the lives of the replacement property under the involuntary conversion provisions. The remaining approximately $1.2 billion of the gain was deferred by reinvesting the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities.

Exelon received the IRS audit report for 1999 through 2001, which reflected the full disallowance of the deferral of gain associated with both the involuntary conversion position and the like-kind exchange transaction. Specifically, the IRS asserted that ComEd was not forced to sell the fossil generating plants and the sales proceeds were therefore not received in connection with an involuntary conversion of certain ComEd property rights. Accordingly, the IRS asserted that the gain on the sale of the assets was fully subject to tax. The IRS also asserted that the Exelon purchase and leaseback transaction is substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax.

Competitive Transition Charges. Exelon contended that the Illinois Act and the Competition Act resulted in the taking of certain of ComEd's and PECO's assets used in their respective businesses of providing electricity services in their defined service areas. Exelon has filed refund claims with the IRS taking the position that CTCs collected during ComEd's and PECO's transition periods represent compensation for that taking and, accordingly, are excludible from taxable income as proceeds from an involuntary conversion. The tax basis of property acquired with the funds provided by the CTCs would be reduced such that the benefits of the position are temporary in nature. The IRS disallowed the refund claims for the 1999-2001 tax years.

Under the Illinois Act, ComEd was required to allow competitors the use of its distribution system resulting in the taking of ComEd's assets and lost asset value (stranded costs). As compensation for the taking, ComEd was permitted to collect a portion of the stranded costs through the collection of CTCs from those customers electing to purchase electricity from providers other than ComEd. ComEd collected approximately $1.2 billion in CTCs for the years 1999-2006.

Similarly, under the Competition Act, PECO was required to allow others the use of its distribution system resulting in the taking of PECO's assets and the stranded costs. Pennsylvania permitted PECO to collect CTCs as compensation for its stranded costs. The PAPUC determined the total amount of stranded costs that PECO was permitted to collect through the CTCs to be $5.3 billion.

2009 Status of Tax Positions. During 2009, Exelon held discussions with IRS Appeals in an attempt to reach a settlement on both the involuntary conversion and like-kind exchange positions, in a manner commensurate with Exelon's and the IRS' respective hazards of litigation with respect to each issue. During the second quarter of 2009, Exelon determined that a settlement with IRS Appeals was unlikely and that Exelon would be required to initiate litigation in order to resolve the issues. Accordingly, Exelon concluded that it had sufficient new information that a remeasurement of these two positions was required in accordance with applicable accounting standards. As a result, Exelon recorded a $31 million (after-tax) interest benefit of which $40 million (after-tax) was recorded at ComEd. The difference in amounts recorded at Exelon and ComEd is due to the method of allocating interest to the Registrants.

Due to the fact that tax litigation often results in a negotiated settlement, as of December 31, 2009, Exelon believed that an eventual settlement on the involuntary conversion position remained a likely outcome. Therefore, Exelon and ComEd established a liability for an unrecognized tax benefit consistent with their view as to a likely settlement.

With regard to the like-kind exchange transaction, as of December 31, 2009, Exelon believed it was likely that the issue would be fully litigated. Exelon assessed in accordance with accounting standards whether it would prevail in litigation. While Exelon recognized the complexity and hazards of this litigation, it believed that it was more likely than not that it would prevail in such litigation and therefore eliminated any liability for unrecognized tax benefits.

In addition to attempting to impose tax on the transactions, the IRS had asserted penalties of approximately $196 million for a substantial understatement of tax. Because Exelon believed it was unlikely that the penalty assertion would ultimately be sustained, Exelon and ComEd had not recorded a liability for penalties as of December 31, 2009.

2010 Status of Tax Positions. In connection with Exelon's discussions with IRS Appeals during the second quarter of 2010, IRS Appeals proposed a settlement offer for the like-kind exchange transaction and involuntary conversion and CTC positions.

Based on the status of these settlement discussions, Exelon concluded that it had sufficient new information that a remeasurement of the involuntary conversion and CTC positions was required in accordance with applicable accounting standards. As a result of the required re-measurement in the second quarter of 2010, Exelon recorded $65 million (after-tax) of interest expense, of which $36 million (after-tax) and $22 million (after-tax) were recorded at ComEd and PECO, respectively. ComEd also recorded a current tax expense of $70 million offset with a tax benefit recorded at Generation of $70 million. The amount recorded at Generation reflects the reduction of current taxes payable and deferred tax liabilities for the increase in tax basis of the related assets transferred from ComEd in accordance with the Contribution Agreement dated January 1, 2001, pursuant to which ComEd's generating business ultimately was transferred to Generation.

In the third quarter of 2010, Exelon and IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions. The agreement is consistent with IRS Appeals' second quarter offer to settle the involuntary conversion and CTC positions and also includes IRS Appeals' agreement to withdraw its assertion of the $110 million substantial understatement penalty with respect to Exelon's involuntary conversion position. Final resolution of the involuntary conversion and CTC disputes remains subject to finalizing terms and calculations and executing definitive agreements satisfactory to both parties. As a result of the preliminary agreement, Exelon and ComEd eliminated any liability for unrecognized tax benefits and established a current tax payable to the IRS.

Under the terms of the preliminary agreement, Exelon estimates that the IRS will assess tax and interest of approximately $300 million in 2011 for the years for which there is a resulting tax deficiency, of which $405 million would be paid by ComEd, $135 million would be received by PECO, $10 million would be paid by Generation and the remainder received by Exelon. These amounts are net of approximately $300 million of refunds due from the settlement of the 2001 tax method of accounting change for certain overhead costs under the SSCM as well as other agreed upon audit adjustments. In order to stop additional interest from accruing on the expected assessment, Exelon made a payment in December 2010 to the IRS of $302 million. See Note 21—Related Party Transactions for the impact of this payment on Exelon's and ComEd's intercompany balances. Further, Exelon expects to receive additional tax refunds of approximately $270 million between 2011 and 2014, of which $335 million would be received by ComEd, $40 million would be paid by Generation and the remainder paid by Exelon.

Also during the third quarter, Exelon and IRS Appeals failed to reach a settlement with respect to the like-kind exchange position. Exelon continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO and does not believe that the concession demanded by the IRS in its settlement offer reflects the strength of Exelon's position. IRS Appeals also continues to assert an $86 million penalty for a substantial understatement of tax with respect to the like-kind exchange position.

While Exelon has been and remains willing to settle the issue in a manner generally commensurate with its hazards of litigation, the IRS has thus far been unwilling to settle the issue without requiring a nearly complete concession of the issue by Exelon.

Accordingly, to continue to contest the IRS's disallowance of the like-kind exchange position and its assertion of the $86 million substantial understatement penalty, Exelon expects to initiate litigation in the second half of 2011 after the final resolution of the involuntary conversion and CTC settlement. Given that Exelon has determined settlement is not a realistic outcome, it has assessed in accordance with applicable accounting standards whether it will prevail in litigation. While Exelon recognizes the complexity and hazards of this litigation, it believes that it is more likely than not that it will prevail in such litigation and therefore eliminated any liability for unrecognized tax benefits. Further, Exelon believes it is unlikely that the penalty assertion will ultimately be sustained, Exelon and ComEd have not recorded a liability for penalties. However, should the IRS prevail in asserting the penalty it would result in an after-tax charge of $86 million to Exelon's and ComEd's results of operations.

As of December 31, 2010, assuming Exelon's preliminary settlement of the involuntary conversion position is finalized, the potential tax and interest, exclusive of penalties, that could become currently payable in the event of a fully successful IRS challenge to Exelon's like-kind exchange position could be as much as $830 million, of which $540 million would be paid by ComEd and the remainder by Exelon. If the IRS were to prevail in litigation on the like-kind exchange position, Exelon's results of operations could be negatively affected due to increased interest expense, as of December 31, 2010, by as much as $230 million (after-tax), of which $180 million would be recorded at ComEd and the remainder by Exelon. Litigation could take several years such that the estimated cash and interest impacts would likely change by a material amount.

Based on Exelon management's expectations as to the potential of a settlement and litigation outcome, it is reasonably possible that the unrecognized tax benefits related to these issues may significantly change within the next 12 months. It is not possible at this time to predict the amount, if any, of such a change.

2011 Illinois State Tax Rate Legislation

The Taxpayer Accountability and Budget Stabilization Act, (SB 2505), enacted into law in Illinois on January 13, 2011, increases the corporate tax rate in Illinois from 7.3% to 9.5% for tax years 2011—2014, provides for a reduction in the rate from 9.5% to 7.75% for tax years 2015—2024 and further reduces the rate from 7.75% to 7.3% for tax years 2025 and thereafter.

The rate change from 7.3% to 9.5% will result in a one-time charge or credit to deferred taxes as the balances must be recalculated at the new corporate tax rates. The Registrants are unable to estimate the impact at this time. Additionally, the rate change will increase future Illinois current state income taxes for Exelon, Generation, and ComEd, including estimated increases in 2011 of approximately $25 million, $10 million and $10 million, respectively.

Illinois Replacement Investment Tax Credits

On February 20, 2009, the Illinois Supreme Court ruled in Exelon's favor in a case involving refund claims for Illinois investment tax credits. Responding to the Illinois Attorney General's petition for rehearing, on July 15, 2009, the Illinois Supreme Court modified its opinion to indicate that it was to be applied only prospectively, beginning in 2009. On December 22, 2009, Exelon filed a Petition of Writ for Certiorari with the United States Supreme Court appealing the Illinois Supreme Court's July 15, 2009 modified opinion. In the third quarter of 2009, Exelon, Generation and ComEd decreased their unrecognized tax benefits related to this position. On March 1, 2010, the United States Supreme Court announced that it would not review the Illinois Supreme Court's decision. As a result of the United States Supreme Court decision, Exelon, Generation and ComEd ceased reporting their unrecognized tax benefits as of March 31, 2010.

Long-Term State Tax Apportionment

Exelon and Generation periodically review events that may significantly impact how income is apportioned among the states and, therefore, the calculation of Exelon's and Generation's deferred state income taxes. On April 16, 2009, the PAPUC approved PECO's electricity procurement proposal that will have an impact on Exelon's and Generation's apportionment of income among the states. Accordingly, Exelon and Generation reevaluated the impacts to deferred state taxes in the second quarter of 2009. The effect of such evaluations resulted in the recording of a non-cash deferred state tax benefit in the amount of $34.7 million, net of taxes. Exelon and Generation have treated electricity as tangible personal property for this purpose which is consistent with the February and July 2009 Illinois Supreme Court decisions. In 2010, the Registrants performed a review of the long-term state tax rates and noted no significant events that would materially impact state apportionment. As such, there was no update to the long-term state apportionment rates in 2010.

Tax Sharing Agreement

Generation, ComEd and PECO are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During 2010, Generation, ComEd and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $60 million, $2 million and $43 million, respectively.

12. Asset Retirement Obligations

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's Consolidated Balance Sheets, from January 1, 2009 to December 31, 2010:

Nuclear decommissioning ARO at January 1, 2009	$3,485
Accretion expense	203
Net decrease due to changes in estimated future cash flows	(409)
Costs incurred to decommission retired plants	(19)
Nuclear decommissioning ARO at December 31, 2009 [(a)]	3,260
Accretion expense	191
Net increase due to changes in estimated future cash flows	624
Extinguishment of Zion Station ARO	(768)
Costs incurred to decommission retired plants	(31)
Nuclear decommissioning ARO at December 31, 2010 [(a)]	$3,276

(a) Includes $5 million and $17 million as the current portion of the ARO at December 31, 2010 and 2009, respectively, which is included in other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

During 2010, Generation recorded a net increase in the ARO of $16 million, primarily reflecting the ZionSolutions' assumption of decommissioning and other liabilities for Zion Station (see discussion below); and increases for accretion and for updates to estimated future cash flows across all of Generation's units. Changes in estimated future cash flows increased the ARO by $624 million, including approximately $200 million associated with the accelerated timing of the Zion Station decommissioning. The remainder of the increase is the result of cost study estimate updates and the change in timing of general decommissioning activities at select sites in Generation's nuclear fleet, including revisions to the timing and amount of SNF disposal; partially offset by the impacts of lower escalation rates. This change in the ARO resulted in an immaterial impact to Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

During 2009, Generation recorded a net decrease in the ARO of $409 million, primarily due to an update in the third quarter of 2009, which reflected updated decommissioning cost studies received for six nuclear units and a decline from the previous year in the cost escalation factor assumptions used to estimate future undiscounted decommissioning costs. This decrease in the ARO resulted in the recognition of $47 million of income (pre-tax), which is included in operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income, representing the reduction in the ARO in excess of the existing ARC balances for the Non-Regulatory Agreement Units.

Zion Station Decommissioning

On December 11, 2007, Generation entered into an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC. (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998.

On September 1, 2010, Generation and EnergySolutions completed the transactions contemplated by the ASA. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities associated with Zion Station. Pursuant to the ASA, ZionSolutions can periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. However, ZionSolutions is subject to certain restrictions on its ability to request that reimbursement; specifically, if certain milestones as defined within the ASA are not met, all or a portion of requested reimbursements shall be deferred until such milestones are met. The transfer of the Zion Station assets did not qualify for asset sale accounting treatment and as a result, the related NDT funds were reclassified to Pledged assets for Zion Station decommissioning within Exelon and Generation's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the extinguished ARO for decommissioning was replaced with a payable to ZionSolutions in Exelon and Generation's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers. Generation has retained its obligation to transfer the SNF at Zion Station to the DOE for ultimate disposal and maintains a liability of approximately $34 million, which is included within the nuclear decommissioning ARO. Generation also has retained a requisite level of NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station. As of December 31, 2010, the carrying value of the Zion Station pledged assets, which include the related NDT funds, and the payable to Zion Solutions were approximately $824 million and $786 million, respectively. The payable excludes a liability recorded within Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT funds. The NDT funds will be utilized to satisfy the tax obligations as gains and losses are realized. The current portion of the payable to ZionSolutions, included in Other Current Liabilities within Generation's Consolidated Balance Sheets, was $127 million. As of December 31, 2010, ZionSolutions has withdrawn approximately $5 million for Zion Station decommissioning costs.

ZionSolutions leased the land associated with Zion Station from Generation pursuant to a Lease Agreement. Under the Lease Agreement, ZionSolutions has committed to complete the required decommissioning work according to an established schedule and will construct a dry cask storage facility on the land for the SNF currently held in SNF pools at Zion Station. Rent payable under the Lease Agreement is $1.00 per year, although the Lease Agreement requires ZionSolutions to pay property taxes associated with Zion Station and penalty rents may accrue if there are unexcused delays in the progress of decommissioning work at Zion Station or the construction of the dry cask SNF storage facility. To reduce the risk of default by EnergySolutions or ZionSolutions, EnergySolutions provided a $200 million letter of credit to be used to fund decommissioning costs in the event the NDT assets are insufficient. EnergySolutions has also provided a performance guarantee and entered into other agreements that will provide rights and remedies for Generation and the NRC in the case of other specified events of default, including a special purpose easement for disposal capacity at the EnergySolutions site in Clive, Utah, for all LLRW volume of Zion Station.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generating station unit to satisfy Generation's nuclear decommissioning obligations. NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with the former ComEd, former PECO and former AmerGen units have been funded with amounts collected from ComEd customers, PECO customers and the previous owners of the former AmerGen plants, respectively. Based on an ICC order, ComEd ceased collecting amounts from its customers to pay for decommissioning costs. PECO currently collects funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are expected to continue through the operating lives of the plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds. Every five years, PECO files a rate adjustment with the PAPUC reflecting updated fund balances and estimated decommissioning costs. The most recent rate adjustment occurred on January 1, 2008 and the effective rates currently yield annual collections of $29 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2013. With respect to the former AmerGen units, Generation does not collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from customers. Apart from the contributions made to the NDT funds from amounts collected from ComEd and PECO customers, Generation has not made contributions to the NDT funds.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation. Generation has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds, on an aggregate basis for all former PECO units, compared to decommissioning obligations, as well as 5% of any additional shortfalls. This initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from ComEd customers for the former ComEd units or from the previous owners of the former AmerGen units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to the former AmerGen units, Generation retains any funds remaining in the NDTs after decommissioning.

At December 31, 2010 and 2009, Exelon had NDT fund investments totaling $6,408 million and $6,669 million, respectively.

During 2010, there were no changes in NDT investment strategy. At December 31, 2010, approximately 57% of the funds were invested in equity and 43% were invested in fixed income securities. At December 31, 2009, approximately 53% of the funds were invested in equity and 47% were invested in fixed income securities.

Securities Lending Program. Generation's NDT funds currently participate in a securities lending program with the trustees of the plans' investment trusts. Under the program, securities loaned by the trustees are required to be collateralized by cash, U.S. Government securities or irrevocable bank letters of credit. Initial collateral levels are no less than 102% and 105% of the market value of the borrowed securities for collateral denominated in U.S. and foreign currency, respectively. Subsequent collateral levels must be maintained at a level no less than 100% of the market value of borrowed securities. Cash collateral received may not be sold or re-pledged by the trustees unless the borrower defaults.

In the fourth quarter of 2008, Exelon decided to end its participation in this securities lending program and initiated a gradual withdrawal of the trusts' investments in order to minimize potential losses due to liquidity constraints in the market. Currently, the weighted average maturity of the securities within the collateral pools is approximately 11 months. The fair value of securities on loan was approximately $51 million and $357 million at December 31, 2010 and 2009, respectively. The fair value of cash and non-cash collateral received for these loaned securities was $51 million and $366 million at December 31, 2010 and 2009, respectively. A portion of the income generated through the investment of cash collateral is remitted to the borrowers, and the remainder is allocated between the trusts and the trustees in their capacity as security agents.

NRC Minimum Funding Requirements. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded on Generation's and Exelon's Consolidated Balance Sheets primarily due to differences in assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees. Key assumptions used in the minimum funding calculation using the NRC methodology at December 31, 2010 include: (1) only one decommissioning scenario for each unit; (2) the plants cease operation at the end of their current license lives (does not include the possibility of license renewal for those units that have not already received renewals, except for Oyster Creek); (3) NRC minimum funding assumes current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (4) annual after-tax returns on the NDT funds are assumed to be 2% (3% for the former PECO units, as specified by the PAPUC). In contrast, Generation's key assumptions related to calculating the ARO and forecasting the target growth in the NDT funds used by Generation at December 31, 2010 include: (1) the ARO is determined using multiple scenarios where decommissioning activities are completed under three possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (2) the plants cease operating at the end of an extended license life (assuming 20-year license renewal extensions); (3) the ARO is the present value of the future obligation and the annual average accretion of the ARO is approximately 6.2% through a period of approximately 30 years after the end of the extended lives of the units; and (4) the estimated targeted annual after-tax return on the NDT funds is 4.6% to 5.4% (as compared to a historical 5-year annual average after-tax return of approximately 5%).

Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of the current approved license life), based on values as of December 31, addressing Generation's ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or make additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, Exelon's and Generation's cash flows and financial position may be significantly adversely affected.

On March 10, 2010, Generation notified the NRC that it had remediated the December 31, 2009 underfunded position of its Byron and Braidwood NDT funds with the establishment of approximately $44 million in parent guarantees in accordance with a plan submitted by Generation to the NRC on July 31, 2009. On May 26, 2010, the NRC notified Generation that while the previously established parent guarantees complied with Generation's remediation plan, additional parent guarantees may be required to meet the future value of the underfunded position. During the third quarter of 2010, Generation established approximately $175 million in additional parent guarantees. Generation has not received any subsequent communication from the NRC following the establishment of these additional parent guarantees.

Generation has determined that as of December 31, 2010, the modest recovery in the financial markets has improved decommissioning funding levels for Byron and Braidwood such that parent guarantees are no longer required to meet the NRC's minimum funding requirements. Generation intends to notify the NRC that parent guarantees are no longer required, on or before the date of the next NRC-required biennial decommissioning funding assurance submission, to be made no later than March 31, 2011. As the future values of trust funds change due to market conditions, the NRC minimum funding status of Generation's units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO nuclear plants, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

Accounting Implications of the Regulatory Agreements with ComEd and PECO. Based on the regulatory agreement with the ICC that dictates Generation's obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis, as long as funds held in the NDT funds exceed the total estimated decommissioning obligation, decommissioning-related activities, including realized and unrealized income and losses on the NDT funds and accretion of the decommissioning obligation, are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability. Should the value of the NDT fund for any former ComEd unit fall below the amount of the estimated decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to Exelon's and Generation's results of operations and financial position could be material. At December 31, 2010, the NDT funds of each of the former ComEd units exceeded the related decommissioning obligation for each of the units. For the purposes of making this determination, the decommissioning obligation referred to is the ARO reflected on Generation's Consolidated Balance Sheets at December 31, 2010 and is different from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

Based on the regulatory agreement supported by the PAPUC that dictates Generation's rights and obligations related to the shortfall or excess of trust funds necessary for decommissioning the seven former PECO nuclear units, regardless of whether the funds held in the NDT funds exceed or fall short of the total estimated decommissioning obligation, decommissioning-related activities are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, PECO has recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability. Any changes to the PECO regulatory agreements could impact Exelon's and Generation's ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon's and Generation's results of operations and financial position could be material. See Note 2—Regulatory Matters for information regarding the approved Settlement permitting the NDCAC to continue after the termination of PECO's CTC collections on December 31, 2010. The Settlement will not result in a material impact to Exelon or Generation's future results of operations, cash flows or financial position.

The decommissioning-related activities related to the Clinton, Oyster Creek and Three Mile Island nuclear plants (the former AmerGen units) and the portions of the Peach Bottom nuclear plants that are not subject to regulatory agreements with respect to the NDT funds are reflected in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income, as there are no regulatory agreements associated with these units. Refer to Note 19—Supplemental Financial Information and Note 21—Related Party Transactions for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund the customers any decommissioning-related assets in excess of the related decommissioning obligations.

The following table provides unrealized gains (losses) on NDT funds for the years ended 2010, 2009 and 2008:

	For the Years Ended December 31,		
	2010	2009	2008
Net unrealized gains (losses) on decommissioning trust funds—Regulatory Agreement Units [(a)(b)]	$294	$799	$(1,023)
Net unrealized gains (losses) on decommissioning trust funds—Non-Regulatory Agreement Units [(c)]	104	227	(324)

(a) Gains related to Generation's NDT funds associated with Regulatory Agreement Units are included in regulatory liabilities on Exelon's Consolidated Balance Sheets and noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $20 million gains related to the Zion Station pledged assets in 2010. Gains related to Zion Station pledged assets are included in payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.
(c) Gains related to Generation's NDT funds associated with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units, which are subject to regulatory accounting, are eliminated within Other, net in Exelon and Generation's Consolidated Statement of Operations and Comprehensive Income.

Non-Nuclear Asset Retirement Obligations

Generation has AROs for plant closure costs associated with its fossil, hydroelectric and wind generating stations, including asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of wind generating stations and other decommissioning-related activities. ComEd and PECO have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1—Significant Accounting Policies for additional information on the Registrants' accounting policy for AROs.

The following table presents the activity of the non-nuclear AROs reflected on Exelon's Consolidated Balance Sheets from January 1, 2009 to December 31, 2010:

Non-nuclear AROs at January 1, 2009	$262
Net increase (decrease) resulting from updates to estimated future cash flows	(81)
Accretion [(a)]	12
Payments	(2)
Non-nuclear AROs at December 31, 2009	191
Net increase (decrease) resulting from updates to estimated future cash flows [(b)]	13
Accretion [(a)]	9
Acquisition of Exelon Wind [(c)]	13
Payments	(3)
Non-nuclear AROs at December 31, 2010	$223

(a) For ComEd and PECO, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.
(b) ComEd and PECO recorded reductions in operating and maintenance expense of $10 million and $1 million, respectively, during the year ended December 31, 2010 relating to updates to estimated future cash flows.
(c) Refer to Note 3—Acquisition for additional information regarding Exelon Wind.

13. Retirement Benefits

As of December 31, 2010, Exelon sponsored five qualified defined benefit pension plans, two non-qualified defined benefit pension plans and three other postretirement benefit plans for essentially all Generation, ComEd, PECO and BSC employees.

Exelon's traditional and cash balance pension plans are intended to be tax-qualified defined benefit plans. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective

January 1, 2009, substantially all newly hired union-represented employees participate in cash balance pension plans. Exelon has elected that the trusts underlying these plans be treated under the IRC as qualified trusts. If certain conditions are met, Exelon can deduct payments made to the qualified trusts, subject to certain IRC limitations.

Benefit Obligations and Plan Assets, and Funded Status

Exelon recognizes the overfunded or underfunded status of defined benefit pension and other postretirement plans as an asset or liability on its balance sheet, with offsetting entries to Accumulated Other Comprehensive Income (AOCI) and regulatory assets, in accordance with the applicable authoritative guidance. The impact of changes in assumptions used to measure pension and other postretirement benefit obligations is generally recognized over the expected average remaining service period of the plan participants. The measurement date for the plans is December 31. The following table provides a rollforward of the changes in the benefit obligations and plan assets for the most recent two years for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
Change in benefit obligation:				
Net benefit obligation at beginning of year	$11,482	$10,788	$3,658	$3,480
Service cost	190	178	124	113
Interest cost	660	651	214	205
Plan participants' contributions	—	—	16	18
Actuarial loss	831	479	49	31
Plan amendments	—	2	—	—
Curtailments/settlements	—	2	—	—
Special termination benefits	—	—	1	4
Gross benefits paid	(639)	(618)	(198)	(203)
Federal subsidy on benefits paid	—	—	10	10
Net benefit obligation at end of year	$12,524	$11,482	$3,874	$3,658
Change in plan assets:				
Fair value of net plan assets at beginning of year	$ 7,839	$ 6,664	$1,476	$1,224
Actual return on plan assets	893	1,352	158	280
Employer contributions	766	441	203	157
Plan participants' contributions	—	—	16	18
Gross benefits paid	(639)	(618)	(198)	(203)
Fair value of net plan assets at end of year	$ 8,859	$ 7,839	$1,655	$1,476

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

	Pension Benefits		Other Postretirement Benefits	
	As of December 31,		As of December 31,	
	2010	2009	2010	2009
Other current liabilities	$ 7	$ 18	$ 1	$ 2
Pension obligations	3,658	3,625	—	—
Non-pension postretirement benefit obligations	—	—	2,218	2,180
Unfunded status (net benefit obligation less net plan assets)	$3,665	$3,643	$2,219	$2,182

The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plan. The funded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following tables provide the projected benefit obligations (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for all pension plans with an ABO in excess of plan assets and a PBO in excess of plan assets.

	PBO and ABO in excess of plan assets	
	December 31,	
	2010	2009
Projected benefit obligation	$12,524	$11,482
Accumulated benefit obligation	11,697	10,695
Fair value of net plan assets	8,859	7,839

On an ABO basis, the plans were funded at 76% at December 31, 2010 compared to 73% at December 31, 2009. On a PBO basis, the plans were funded at 71% at December 31, 2010 compared to 68% at December 31, 2009. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2010, 2009 and 2008 for all plans combined. The table reflects a reduction in 2010, 2009 and 2008 of net periodic postretirement benefit costs of approximately $38 million for each year, related to a Federal subsidy provided under the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Modernization Act), discussed further below.

	Pension Benefits			Other Postretirement Benefits		
	2010	2009	2008	2010	2009	2008
Components of net periodic benefit cost:						
Service cost	$ 190	$ 178	$ 163	$ 124	$113	$ 108
Interest cost	660	651	635	214	205	208
Expected return on assets	(799)	(778)	(836)	(109)	(94)	(121)
Amortization of:						
Transition obligation	—	—	—	9	9	10
Prior service cost (credit)	14	14	15	(56)	(56)	(57)
Actuarial loss	254	197	127	74	87	53
Curtailment/settlement charges	5	6	9	—	—	—
Special termination benefits	—	—	—	1	4	—
Net periodic benefit cost	$ 324	$ 268	$ 113	$ 257	$268	$ 201

Through Exelon's postretirement benefit plans, the Registrants provide retirees with prescription drug coverage. The Medicare Modernization Act, enacted on December 8, 2003, introduced a prescription drug benefit under Medicare as well as a Federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the Medicare prescription drug benefit. Management believes the prescription drug benefit provided under Exelon's postretirement benefit plans meets the requirements for the subsidy. See the Health Care Reform Legislation section below for further discussion regarding the income tax treatment of Federal subsidies of prescription drug benefits.

The effect of the subsidy on the components of net periodic postretirement benefit cost for 2010, 2009 and 2008 included in the consolidated financial statements was as follows:

	2010	2009	2008
Amortization of the actuarial experience loss	$ 9	$11	$11
Reduction in current period service cost	10	9	9
Reduction in interest cost on the APBO	19	18	18
Total effect of subsidy on net periodic postretirement benefit cost	$38	$38	$38

Components of OCI and Regulatory Assets

Under the authoritative guidance for regulatory accounting, a portion of current year actuarial gains and losses and prior service costs (credits) is capitalized within Exelon's Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts, which would otherwise be recorded to OCI. The following tables provide the components of OCI and regulatory assets for the years ended December 31, 2010, 2009 and 2008 for all plans combined.

	Pension Benefits			Other Postretirement Benefits		
	2010	2009	2008	2010	2009	2008
Changes in plan assets and benefit obligations recognized in OCI and regulatory assets:						
Current year actuarial (gain) loss	$ 737	$ (94)	$3,432	$—	$(154)	$495
Amortization of actuarial gain (loss)	(254)	(197)	(127)	(74)	(87)	(53)
Current year prior service cost	—	2	16	—	—	—
Amortization of prior service cost (credit)	(14)	(14)	(15)	56	56	57
Amortization of transition obligation	—	—	—	(9)	(9)	(10)
Settlements	(5)	(6)	(9)	—	—	—
Total recognized in OCI and regulatory assets (a)	$ 464	$(309)	$3,297	$(27)	$(194)	$489

(a) Of the $464 million related to pension benefits, $310 million and $154 million were recognized in AOCI and regulatory assets, respectively, during 2010. Of the $(27) million related to other postretirement benefits, $(9) million and $(18) million were recognized in AOCI and regulatory assets, respectively, during 2010. Of the $(309) million related to pension benefits, $(204) million and $(105) million were recognized in AOCI and regulatory assets, respectively, during 2009. Of the $(194) million related to other postretirement benefits, $(85) million and $(109) million were recognized in AOCI and regulatory assets, respectively, during 2009. Of the $3,297 related to pension benefits, $2,069 million and $1,228 million were recognized in AOCI and regulatory assets, respectively, during 2008. Of the $489 million related to other postretirement benefits, $245 million and $244 million were recognized in AOCI and regulatory assets, respectively, during 2008.

The following table provides the components of Exelon's gross accumulated other comprehensive loss and regulatory assets that have not been recognized as components of periodic benefit cost as of December 31, 2010 and 2009, respectively, for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	As of December 31,		As of December 31,	
	2010	2009	2010	2009
Transition obligation	$ —	$ —	$ 20	$ 29
Prior service cost (credit)	104	118	(54)	(110)
Actuarial loss	6,316	5,838	955	1,029
Total (a)	$6,420	$5,956	$921	$ 948

(a) Of the $6,420 million related to pension benefits, $4,129 million and $2,291 million are included in AOCI and regulatory assets, respectively, as of December 31, 2010. Of the $921 million related to other postretirement benefits, $462 million and $459 million are included in AOCI and regulatory assets, respectively, as of December 31, 2010. Of the $5,956 million related to pension benefits, $3,819 million and $2,137 million are included in AOCI and regulatory assets, respectively, as of December 31, 2009. Of the $948 million related to other postretirement benefits, $470 million and $478 million are included in AOCI and regulatory assets, respectively, as of December 31, 2009.

The following table provides the components of Exelon's AOCI and regulatory assets as of December 31, 2010 (included in the table above) that are expected to be amortized as components of periodic benefit cost in 2011. These estimates are subject to the completion of an actuarial valuation of Exelon's pension and other postretirement benefit obligations, which will reflect actual census data as of January 1, 2011 and actual claims activity as of December 31, 2010. The valuation is expected to be completed in the first quarter of 2011.

	Pension Benefits	Other Postretirement Benefits
Transition obligation	$—	$ 9
Prior service cost (credit)	14	(38)
Actuarial loss	334	64
Total [(a)]	$348	$ 35

(a) Of the $348 million related to pension benefits as of December 31, 2010, $213 million and $135 million are expected to be amortized from AOCI and regulatory assets in 2011, respectively. Of the $35 million related to other postretirement benefits as of December 31, 2010, $15 million and $20 million are expected to be amortized from AOCI and regulatory assets in 2011, respectively.

Assumptions

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit and other postretirement plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Exelon's expected level of contributions to the plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, the long-term expected investment rate credited to employees of certain plans and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure pension and other postretirement benefit obligations is generally recognized over the expected average remaining service period of the plan participants.

Expected Rate of Return. In selecting the expected rate of return on plan assets, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by Exelon's target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed income securities.

The following weighted average assumptions were used to determine the benefit obligations for all of the plans at December 31, 2010, 2009 and 2008. Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits			Other Postretirement Benefits		
	2010	2009	2008	2010	2009	2008
Discount rate	5.26%	5.83%	6.09%	5.30%	5.83%	6.09%
Rate of compensation increase	3.75%	4.00%	4.00%	3.75%	4.00%	4.00%
Mortality table	IRS required mortality table for 2011 funding valuation	IRS required mortality table for 2010 funding valuation	IRS required mortality table for 2009 funding valuation	IRS required mortality table for 2011 funding valuation	IRS required mortality table for 2010 funding valuation	IRS required mortality table for 2009 funding valuation
Health care cost trend on covered charges	N/A	N/A	N/A	7.00% decreasing to ultimate trend of 5.00% in 2015	7.50% decreasing to ultimate trend of 5.00% in 2015	7.50% decreasing to ultimate trend of 5.00% in 2014

The following weighted average assumptions were used to determine the net periodic benefit costs for all the plans for the years ended December 31, 2010, 2009 and 2008:

	Pension Benefits			Other Postretirement Benefits		
	2010	2009	2008	2010	2009	2008
Discount rate	5.83%	6.09%	6.20%	5.83%	6.09%	6.20%
Expected return on plan assets	8.50% (a)	8.50% (a)	8.75% (a)	7.83% (a)	8.10% (a)	7.80% (a)
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Mortality table	IRS required mortality table for 2010 funding valuation	IRS required mortality table for 2009 funding valuation	IRS required mortality table for 2008 funding valuation	IRS required mortality table for 2010 funding valuation	IRS required mortality table for 2009 funding valuation	IRS required mortality table for 2008 funding valuation
Health care cost trend on covered charges	N/A	N/A	N/A	7.50% decreasing to ultimate trend of 5.00% in 2015	7.50% decreasing to ultimate trend of 5.00% in 2014	8.00% decreasing to ultimate trend of 5.00% in 2014

(a) Not applicable to pension and other postretirement benefit plans that do not have any plan assets.

Assumed health care cost trend rates have a significant effect on the costs reported for the other postretirement benefit plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

Effect of a one percentage point increase in assumed health care cost trend	
on 2010 total service and interest cost components	$ 53
on postretirement benefit obligation at December 31, 2010	490
Effect of a one percentage point decrease in assumed health care cost trend	
on 2010 total service and interest cost components	(43)
on postretirement benefit obligation at December 31, 2010	(405)

Health Care Reform Legislation

In March 2010, the Health Care Reform Acts were signed into law. A number of provisions in the Health Care Reform Acts impact retiree health care plans provided by employers. One such provision reduces the deductibility, for Federal income tax purposes, of retiree health care costs to the extent an employer's postretirement health care plan receives Federal subsidies that provide retiree prescription drug benefits at least equivalent to those offered by Medicare. Although this change did not take effect immediately, the Registrants were required to recognize the full accounting impact in their financial statements in the period in which the legislation was enacted. As a result, in the first quarter of 2010, Exelon recorded total after-tax charges of approximately $65 million to income tax expense to reverse deferred tax assets previously established. Of this total, Generation, ComEd and PECO recorded charges of $24 million, $11 million and $9 million, respectively.

Additionally, the Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. The application of the legislation is still unclear and Exelon continues to monitor for additional guidance from the Department of Labor and IRS. Certain key assumptions are required to estimate the impact of the excise tax on Exelon's postretirement benefit obligation, including projected inflation rates (based on the Consumer Price Index) and whether pre- and post-65 retiree populations can be aggregated in determining the premium values of health care benefits. Exelon reflected its best estimate of the excise tax impact in its annual actuarial measurement, which increased its postretirement benefit obligation by $145 million as of December 31, 2010.

Exelon contributed $2.1 billion to its qualified pension plans in January 2011. No further contributions to the qualified pension plans are currently anticipated for 2011. Exelon plans to contribute $6 million to its non-qualified pension plans in 2011. Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension

Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification).

Unlike the qualified pension plans, Exelon's other postretirement plans are not subject to regulatory minimum contribution requirements. Management considers several factors in determining the level of contributions to Exelon's other postretirement benefit plans, including levels of benefit claims paid and regulatory implications. Exelon expects to contribute approximately $185 million to the other postretirement benefit plans in 2011.

During the first quarter of 2011, Exelon will receive an updated valuation of its pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2011.

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans as of December 31, 2010 were:

	Pension Benefits	Other Postretirement Benefits (a)
2011	$ 716	$ 190
2012	669	197
2013	701	207
2014	694	215
2015	788	225
2016 through 2020	4,079	1,318
Total estimated future benefits payments through 2020	$7,647	$2,352

(a) Estimated future benefit payments do not reflect an anticipated Federal subsidy provided through the Medicare Modernization Act. The Federal subsidies to be received by Exelon in the years 2011, 2012, 2013, 2014, 2015 and from 2016 through 2020 are estimated to be $8 million, $9 million, $10 million, $11 million, $12 million and $77 million, respectively.

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

In the second quarter of 2010, Exelon modified its pension investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. As a result of this modification, over time, Exelon determined that it will decrease equity investments and increase investments in fixed income securities and alternative investments in order to achieve a balanced portfolio of risk-reducing and return-seeking assets. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. Over the next several years, Exelon expects to migrate to a target asset allocation of approximately 30% public equity investments, 50% fixed income investments and 20% alternative investments.

The change in the overall investment strategy would tend to lower the expected rate of return on plan assets in future years as compared to the previous strategy. Exelon used an EROA of 8.00% and 7.08% to estimate its 2011 pension and other postretirement benefit costs, respectively.

Exelon's pension and other postretirement benefit plan target asset allocations and December 31, 2010 and 2009 weighted average asset allocations were as follows:

Pension Plans

Asset Category	Target Allocation	Percentage of Plan Assets at December 31, 2010	2009
Equity securities	25-35 %	45%	56%
Fixed income securities	45-55 %	41	34
Alternative investments [(a)]	15-25 %	14	10
Total		100%	100%

Other Postretirement Benefit Plans

Asset Category	Target Allocation	Percentage of Plan Assets at December 31, 2010	2009
Equity securities	40-50 %	54%	64%
Fixed income securities	35-45 %	45	36
Alternative investments [(a)]	10-20 %	1	—
Total		100%	100%

(a) Alternative investments include real estate, private equity and hedge fund investments.

Securities Lending Programs. The majority of the benefit plans currently participate in a securities lending program with the trustees of the plans' investment trusts. Under the program, securities loaned to the trustees are required to be collateralized by cash, U.S. Government securities or irrevocable bank letters of credit. Initial collateral levels are no less than 102% and 105% of the market value of the borrowed securities for collateral denominated in U.S. and foreign currency, respectively. Subsequent collateral levels must be maintained at a level no less than 100% of the market value of borrowed securities. Cash collateral received may not be sold or re-pledged by the trustees unless the borrower defaults.

In the fourth quarter of 2008, Exelon decided to end its participation in this securities lending program and initiated a gradual withdrawal of the trusts' investments in order to minimize potential losses due to liquidity constraints in the market. Currently, the weighted average maturity of the securities within the collateral funds is approximately 7 months. The fair value of securities on loan was approximately $46 million and $356 million at December 31, 2010 and 2009, respectively. The fair value of cash and non-cash collateral received for these loaned securities was $47 million at December 31, 2010 and $365 million at December 31, 2009. A portion of the income generated through the investment of cash collateral is remitted to the borrowers, and the remainder is allocated between the trusts and the trustees in their capacity as security agents.

Concentrations of Credit Risk. Exelon evaluated its pension and other postretirement benefit plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2010. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2010, there were no significant concentrations (defined as greater than 10 percent of plan assets) of risk in Exelon's pension and other postretirement benefit plan assets.

Fair Value Measurements

The following table presents Exelon's pension and other postretirement benefit plan assets measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2010 and 2009:

As of December 31, 2010 [(a)(f)]	**Level 1**	**Level 2**	**Level 3**	**Total**
Pension plan assets				
Cash equivalents	$ 2	$ —	$ —	$ 2
Equity securities [(b)]	1,528	—	—	1,528
Commingled funds [(c)]	485	3,704	—	4,189
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies [(d)]	1,144	93	—	1,237
Debt securities issued by states of the United States and by political subdivisions of the states [(d)]	—	15	—	15
Corporate debt securities [(d)]	—	312	—	312
Federal agency mortgage-backed securities [(e)]	—	226	—	226
Non-Federal agency mortgage-backed securities [(e)]	—	82	—	82
Fixed income subtotal	1,144	728	—	1,872
Private equity	—	—	536	536
Hedge funds	—	—	329	329
Real estate	178	—	179	357
Pension plan assets subtotal	$3,337	$4,432	$1,044	$ 8,813
Other postretirement benefit plan assets				
Cash equivalents	—	—	—	—
Equity securities [(b)]	225	—	—	225
Commingled funds [(c)]	118	1,103	5	1,226
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies [(d)]	25	2	—	27
Debt securities issued by states of the United States and by political subdivisions of the states [(d)]	—	100	—	100
Corporate debt securities [(d)]	—	13	—	13
Federal agency mortgage-backed securities [(e)]	—	41	—	41
Non-Federal agency mortgage-backed securities [(e)]	—	7	—	7
Fixed income subtotal	25	163	—	188
Hedge funds	—	—	5	5
Real estate	8	—	3	11
Other postretirement benefit plan assets subtotal	$ 376	$1,266	$ 13	$ 1,655
Total pension and other postretirement benefit plan assets	$3,713	$5,698	$1,057	$10,468

As of December 31, 2009 [(a)(f)]	Level 1	Level 2	Level 3	Total
Pension plan assets				
Cash equivalents	$ 37	$ —	$—	$ 37
Equity securities [(b)]	1,357	—	—	1,357
Commingled funds [(c)]	515	3,641	—	4,156
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies [(d)]	140	23	—	163
Debt securities issued by states of the United States and by political subdivisions of the states [(d)]	—	11	—	11
Corporate debt securities [(d)]	—	245	—	245
Federal agency mortgage-backed securities [(e)]	—	825	—	825
Non-Federal agency mortgage-backed securities [(e)]	—	342	—	342
Fixed income subtotal	140	1,446	—	1,586
Private equity	—	—	450	450
Real estate	154	—	156	310
Pension plan assets subtotal	$2,203	$5,087	$606	$7,896
Other postretirement benefit plan assets				
Cash equivalents	4	—	—	4
Equity securities [(b)]	199	—	—	199
Commingled funds [(c)]	112	894	—	1,006
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies [(d)]	14	2	—	16
Debt securities issued by states of the United States and by political subdivisions of the states [(d)]	—	103	—	103
Corporate debt securities [(d)]	—	20	—	20
Federal agency mortgage-backed securities [(e)]	—	94	—	94
Non-Federal agency mortgage-backed securities [(e)]	—	34	—	34
Fixed income subtotal	14	253	—	267
Real estate	1	—	—	1
Other postretirement benefit plan assets subtotal	$ 330	$1,147	$—	$1,477
Total pension and other postretirement benefit plan assets	$2,533	$6,234	$606	$9,373

(a) See Note 8 – Fair Value of Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) The performance of equity portfolios is benchmarked against established indices.
(c) This category represents commingled fund investments in equity and fixed income securities. The commingled funds seek to out-perform certain established indices.
(d) This category predominantly represents diverse issues of domestic, investment-grade fixed income securities.
(e) This category represents investments in Federal agency, commercial and residential mortgage-backed securities that seek to out-perform certain bond indices.
(f) The total fair value of pension and other postretirement benefit plan assets excludes $21 million and $20 million of interest and dividends receivable and $25 million and $40 million related to pending sales transactions as of December 31, 2010 and 2009, respectively. Additionally, the table excludes collateral fund assets of $47 million and $365 million and collateral liabilities of $47 million and $365 million as of December 31, 2010 and 2009, respectively, in connection with the benefit plans' participation in securities lending programs.

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value for pension and other postretirement benefit plans during the years ended December 31, 2010 and 2009:

	Hedge funds	Private equity	Commingled Funds	Real estate	Total
Pension Assets					
Balance as of January 1, 2010	$—	$450	$—	$156	$ 606
Actual return on plan assets:					
Relating to assets still held at the reporting date	14	37	—	13	64
Purchases, sales and settlements	315	49	—	10	374
Balance as of December 31, 2010	$329	$536	$—	$179	$1,044
Other Postretirement Benefits					
Balance as of January 1, 2010	$—	$—	$—	$—	$ —
Actual return on plan assets:					
Relating to assets still held at the reporting date	—	—	1	1	2
Purchases, sales and settlements	5	—	—	2	7
Transfers into (out of) Level 3 (a)	—	—	4	—	4
Balance as of December 31, 2010	$ 5	$—	$ 5	$ 3	$ 13

	Private equity	Real estate	Total
Pension Assets			
Balance as of January 1, 2009	$ 808	$232	$1,040
Actual return on plan assets:			
Relating to assets still held at the reporting date	57	(88)	(31)
Relating to assets sold during the period	35	—	35
Purchases, sales and settlements	136	12	148
Transfers into (out of) Level 3	(586)	—	(586)
Balance as of December 31, 2009	$ 450	$156	$ 606
Other Postretirement Benefits			
Balance as of January 1, 2009	$ 53	$—	$ 53
Actual return on plan assets:			
Relating to assets still held at the			
Relating to assets sold during the period	23	—	23
Transfers into (out of) Level 3	(76)	—	(76)
Balance as of December 31, 2009	$ —	$—	$ —

(a) Commingled fund investments determined to be liquid during 2010 were transferred into Level 3.

Valuation Techniques Used to Determine Fair Value

Cash equivalents. Investments with maturities of three months or less when purchased, including certain short-term fixed-income securities, are considered cash equivalents and are included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

Equity securities. With respect to individually held equity securities, including investments in U.S. and international securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Exelon is able to independently corroborate. Equity securities held individually are primarily traded on exchanges which contain only actively traded securities due to the volume trading requirements imposed by these exchanges. Equity securities are valued based on quoted prices in active markets and are categorized as Level 1.

Commingled funds. Commingled funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Commingled funds seek to generate returns through a broad range of strategies. The values of the majority of commingled funds are not publicly quoted. For equity and fixed-income commingled funds which are not publicly traded, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Equity and fixed-income funds with publicly quoted prices have been categorized as Level 1.

Private equity investments. Private equity investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include leveraged buyouts, venture capital, distressed investments and investments in natural resources. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments which include inputs such as cost, operating results, discounted future cash flows and market based comparable data. Since these valuation inputs are not highly observable, private equity investments have been categorized as Level 3.

Hedge fund investments. Hedge fund investments include those seeking to maximize absolute returns using a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is estimated using net asset value per share (NAV) of the investments. Exelon has the ability to redeem these investments at NAV within the near term. Since these valuations are not highly observable, hedge fund investments have been categorized as Level 3.

Fixed-income securities. For fixed income securities, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Exelon has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon selectively corroborates the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized in Level 1 because they trade in highly-liquid and transparent markets. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2. To draw parallels from the trading and quoting of fixed income securities with similar features, pricing services consider various characteristics including the issuer, maturity, purpose of loan, collateral attributes, prepayment speeds, interest rates and credit ratings in order to properly value these securities.

Real Estate. Real estate investment trusts are valued daily based on quoted prices in active markets and are categorized as Level 1. Real estate commingled funds are funds with a direct investment in a pool of real estate properties. These funds are valued by investment managers on a periodic basis using pricing models that use independent appraisals from sources with professional qualifications. Since these valuation inputs are not highly observable, real estate commingled funds have been categorized as Level 3 investments.

401(k) Savings Plan

Exelon participates in a 401(k) savings plan. The plan allows employees to contribute a portion of their pre-tax income in accordance with specified guidelines. Exelon matches a percentage of the employee contribution up to certain limits. The cost of matching contributions to the savings plan totaled the following:

For the Years Ended	
2010	$81
2009	70
2008	66

14. Corporate Restructuring and Plant Retirements

The Registrants provide severance and health and welfare benefits to terminated employees primarily based upon each individual employee's years of service and compensation level. The Registrants accrue amounts associated with severance benefits that are considered probable and that can be reasonably estimated.

The following tables present total severance benefits costs, recorded as operating and maintenance expense in relation to the announced job reductions, for the years ended December 31, 2010 and 2009:

Severance benefits expense	
Corporate restructuring—2009 [(a)]	$34
Plant retirements—2010	4
Plant retirements—2009	7
Total severance benefits expense	$45

(a) Severance benefits include $4 million of contractual termination benefits expense for which the obligation is recorded in other postretirement benefits.

Corporate restructuring (Exelon, Generation, ComEd and PECO). In June 2009, Exelon announced a restructured senior executive team and major spending cuts, including the elimination of approximately 500 employee positions. Exelon eliminated approximately 400 corporate support positions, mostly located at corporate headquarters, and 100 management level positions at ComEd, the majority of which was completed by September 30, 2009. These actions were in response to the continuing economic challenges confronting all parts of Exelon's business and industry especially in light of the commodity-driven nature of Generation's markets, necessitating continued focus on cost management through enhanced efficiency and productivity.

Exelon recorded a pre-tax charge for estimated salary continuance and health and welfare severance benefits of $40 million in June 2009 as a result of the planned job reductions. Subsequent to June 2009, Exelon recorded a net pre-tax credit of approximately $6 million, which included a $10 million reduction in estimated salary continuance and health and welfare severance benefits, offset by $4 million of expense for contractual termination benefits. Cash payments under the plan began in July 2009 and were substantially completed at December 31, 2010.

The following table presents the activity of severance obligations for the corporate restructuring from January 1, 2010 through December 31, 2010, excluding obligations recorded in equity:

Severance Benefits Obligation	
Balance at January 1, 2009	$—
Severance charges recorded	39
Cash payments	(10)
Other adjustments	(10)
Balance at December 31, 2009	19
Cash payments	(18)
Balance at December 31, 2010	$ 1

Plant Retirements. On December 8, 2010, in connection with the executed Administrative Consent Order (ACO) with the NJDEP, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. See Note 18 for additional information regarding the closure of Oyster Creek.

On December 2, 2009, Exelon announced its intention to permanently retire three coal-fired generating units and one oil/gas-fired generating unit, effective May 31, 2011. The units to be retired are Cromby Generating Station (Cromby) Unit 1 and Unit 2 and Eddystone Generating Station (Eddystone) Unit 1 and Unit 2. These actions were in response to the economic outlook related to the continued operation of these four units. Subsequently, PJM determined that transmission reliability upgrades will be necessary to alleviate reliability impacts and that those upgrades will be completed in a manner that will permit Generation's retirement of the units on the following schedule: Cromby Unit 1 and Eddystone Unit 1 on May 31, 2011; Cromby Unit 2 on December 31, 2011; and Eddystone Unit 2 on June 1, 2012. These dates are dependent upon the completion of required transmission reliability upgrades and may be subject to further change. Generation revised the depreciable useful lives for these affected units to reflect the aforementioned anticipated deactivation dates. On June 10, 2010, Generation filed with FERC a reliability-must-run rate schedule providing the terms, conditions and cost-based rates under which Generation will continue to operate Cromby Unit 2 and Eddystone Unit 2 for reliability purposes beyond their planned May 31, 2011 deactivation date. As a result of a proposed settlement reached with FERC Staff and other intervenors on December 14, 2010 regarding the terms of the reliability-must-run rate schedule, which is subject to FERC approval, the total compensation under the reliability-must-run rate schedule would be approximately $6 million and

$2 million of monthly fixed-cost recovery for Generation during the reliability-must-run period for Eddystone Unit 2 and Cromby Unit 2, respectively. In addition, Exelon Generation will be reimbursed for variable costs including fuel, emissions costs, chemicals, auxiliary power and for project investment costs during the reliability-must-run period.

Such revenue is intended to recover total expected operating costs, plus a return on net assets, of the two units during the reliability-must-run period. In connection with these retirements, Exelon will eliminate approximately 280 employee positions, the majority of which are located at the units to be retired. Total expected costs for Generation related to the announced retirements is $38 million, which includes $15 million for estimated salary continuance and health and welfare severance benefits, a $17 million write down of inventory and $6 million of shut down and other related costs. Cash payments under this plan began in January 2010 and will continue through 2013. Additionally, total expected accelerated depreciation expense is approximately $206 million.

During 2009, Generation recorded a pre-tax charge of $24 million related to the announced retirements, which included a $7 million charge for estimated salary continuance and health and welfare severance benefits, and $17 million of expense for the write down of inventory recorded within operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Additionally, during 2009, Generation recorded $32 million of accelerated depreciation expense within depreciation and amortization expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. During the year ended December 31, 2010, Generation recorded a net $3 million charge which is primarily due to an increase in estimated salary continuance and health and welfare severance benefits and $80 million of accelerated depreciation expense.

The following table presents the activity of severance obligations for the announced Cromby and Eddystone retirements from January 1, 2010 through December 31, 2010:

Severance Benefits Obligation	
Balance at January 1, 2009	$—
Severance charges recorded	7
Balance at December 31, 2009	7
Severance charges recorded	4
Cash payments	(1)
Other adjustments	(3)
Balance at December 31, 2010	$ 7

15. Preferred Securities

At December 31, 2010 and 2009, Exelon was authorized to issue up to 100,000,000 shares of preferred securities, none of which were outstanding.

Preferred and Preference Securities of Subsidiaries

At December 31, 2010 and 2009, ComEd prior preferred securities and ComEd cumulative preference securities consisted of 850,000 shares and 6,810,451 shares authorized, respectively, none of which were outstanding.

At December 31, 2010 and 2009, PECO cumulative preferred securities, no par value, consisted of 15,000,000 shares authorized and the outstanding amounts set forth below. Shares of preferred securities have full voting rights, including the right to cumulate votes in the election of directors.

	Redemption Price [(a)]	December 31, 2010	December 31, 2009	December 31, 2010	December 31, 2009
		Shares Outstanding		Dollar Amount	
Series (without mandatory redemption)					
$4.68 (Series D)	$104.00	150,000	150,000	$15	$15
$4.40 (Series C)	112.50	274,720	274,720	27	27
$4.30 (Series B)	102.00	150,000	150,000	15	15
$3.80 (Series A)	106.00	300,000	300,000	30	30
Total preferred securities		874,720	874,720	$87	$87

(a) Redeemable, at the option of PECO, at the indicated dollar amounts per share, plus accrued dividends.

16. Common Stock

At December 31, 2010 and 2009, Exelon's common stock without par value consisted of 2,000,000,000 shares authorized and 661,845,411 and 659,798,515 shares outstanding, respectively. At December 31, 2010 and 2009, ComEd's common stock with a $12.50 par value consisted of 250,000,000 shares authorized and 127,016,519 shares outstanding. At December 31, 2010 and 2009, PECO's common stock without par value consisted of 500,000,000 shares authorized and 170,478,507 shares outstanding.

ComEd had 75,139 and 75,294 warrants outstanding to purchase ComEd common stock as of December 31, 2010 and 2009, respectively. The warrants entitle the holders to convert such warrants into common stock of ComEd at a conversion rate of one share of common stock for three warrants. At December 31, 2010 and 2009, 25,046 and 25,098 shares of common stock, respectively, were reserved for the conversion of warrants.

Share Repurchases

Share Repurchase Programs. In April 2004, Exelon's Board of Directors approved a discretionary share repurchase program that allowed Exelon to repurchase shares of its common stock on a periodic basis in the open market. The share repurchase program was intended to mitigate, in part, the dilutive effect of shares issued under Exelon's employee stock option plan and Exelon's ESPP. The aggregate value of the shares of common stock repurchased pursuant to the program cannot exceed the economic benefit received after January 1, 2004 due to stock option exercises and share purchases pursuant to Exelon's ESPP. The economic benefit consists of the direct cash proceeds from purchases of stock and the tax benefits associated with exercises of stock options. The 2004 share repurchase program had no specified limit on the number of shares that could be repurchased and no specified termination date. Any shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon's management.

In the third quarter of 2008, Exelon's Board of Directors approved a share repurchase program for $1.5 billion of its common stock. Subsequently, Exelon management determined to defer indefinitely any share repurchases. This decision was made in light of a variety of factors, including: developments affecting the world economy and commodity markets, including those for electricity and gas; the continued uncertainty in capital and credit markets and the potential impact of those events on Exelon's future cash needs; projected cash needs to support investment in the business, including maintenance capital and nuclear uprates; and value-added growth opportunities.

Under the share repurchase programs dating back to 2004, 34.7 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of December 31, 2010. During 2010 and 2009, Exelon had no common stock repurchases.

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes performance share awards, stock options and restricted stock units. At December 31, 2010, there were approximately 21 million shares authorized for issuance under the LTIP. During the years ended December 31, 2010, 2009 and 2008, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

As the LTIP sponsor, Exelon is the sole issuer of all stock-based compensation awards. All awards are recorded as equity or a liability in Exelon's Consolidated Balance Sheets. The stock-based compensation expense specifically attributable to the employees of Generation, ComEd and PECO is directly recorded to operating and maintenance expense within each of their respective Consolidated Statements of Operations and Comprehensive Income. Stock-based compensation expense attributable to BSC employees is allocated to the Registrants using a cost-causative allocation method.

The following table presents the stock-based compensation expense included in Exelon's Consolidated Statements of Operations during the years ended December 31, 2010, 2009 and 2008:

Components of Stock-Based Compensation Expense	Year Ended December 31, 2010	2009	2008
Performance shares	$ 6	$ 31	$ 28
Stock options	10	20	24
Restricted stock units	21	26	20
Other stock-based awards	4	4	4
Total stock-based compensation included in operating and maintenance expense	41	81	76
Income tax benefit	(16)	(32)	(29)
Total after-tax stock-based compensation expense	$ 25	$ 49	$ 47

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2010, 2009 and 2008.

Exelon receives a tax deduction based on the intrinsic value of the award on the exercise date for stock options and distribution date for performance share awards and restricted stock units. For each award, throughout the requisite service period, Exelon recognizes the tax benefit related to compensation costs. The tax deductions in excess of the benefits recorded throughout the requisite service period are recorded to common stock and are included in other financing activities within Exelon's Consolidated Statements of Cash Flows. The following table presents information regarding Exelon's tax benefits during the years ended December 31, 2010, 2009 and 2008:

	Year Ended December 31, 2010	2009	2008
Realized tax benefit when exercised/distributed:			
Stock options	$ 5	$ 6	$59
Restricted stock units	9	7	4
Performance share awards	13	19	27
Stock deferral plan	1	1	10
Excess tax benefits included in other financing activities of Exelon's Consolidated Statements of Cash Flows:			
Stock options	3	4	51
Restricted stock units	—	—	1
Performance share awards	—	—	2
Stock deferral plan	—	—	6

Stock Options

Non-qualified stock options to purchase shares of Exelon's common stock are granted under the LTIP. The exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. Stock options granted under the LTIP generally become exercisable upon a specified vesting date. The vesting period of stock options is generally four years. All stock options expire ten years from the date of grant.

The value of stock options at the date of grant is expensed over the requisite service period using the straight-line method. The requisite service period for stock options is generally four years. However, certain stock options become fully vested upon the employee reaching retirement-eligibility. The value of the stock options granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility.

Exelon grants most of its stock options in the first quarter of each year. Stock options granted during the remaining quarters of 2010, 2009 and 2008 were not significant.

The fair value of each option is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The following table presents the weighted average assumptions used in the pricing model for grants and the resulting weighted average grant date fair value of stock options granted for the years ended December 31, 2010, 2009 and 2008:

	Year Ended December 31,		
	2010	2009	2008
Dividend yield	4.56%	3.72%	2.73%
Expected volatility	27.10%	36.70%	29.30%
Risk-free interest rate	2.96%	2.01%	3.17%
Expected life (years)	6.25	6.25	6.25
Weighted average grant date fair value (per share)	$ 8.08	$14.43	$18.36

The dividend yield is based on several factors, including Exelon's most recent dividend payment at the grant date and the average stock price over the previous year. Expected volatility is based on implied volatilities of traded stock options in Exelon's common stock and historical volatility over the estimated expected life of the stock options. The risk-free interest rate for a security with a term equal to the expected life is based on a yield curve constructed from U.S. Treasury strips at the time of grant. For each year presented, the expected life represents the period of time the stock options are expected to be outstanding and is based on the simplified method. Exelon believes that the simplified method is appropriate due to several factors that result in historical exercise data not being sufficient to determine a reasonable estimate of expected term. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following table presents information with respect to stock option activity during the year ended December 31, 2010:

	Shares	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
Balance of shares outstanding at December 31, 2009	11,437,541	$47.12		
Options granted	1,019,500	46.09		
Options exercised	(870,937)	27.92		
Options forfeited	(134,789)	56.60		
Options expired	(242,312)	48.18		
Balance of shares outstanding at December 31, 2010	11,209,003	$48.39	5.13	$30
Exercisable at December 31, 2010 [a]	10,266,478	$47.84	4.85	$30

(a) Includes stock options issued to retirement eligible employees.

The following table summarizes additional information regarding stock options exercised during the years ended December 31, 2010, 2009 and 2008:

	Year Ended December 31,		
Stock Options Exercised	2010	2009	2008
Intrinsic value [a]	$13	$15	$147
Cash received for exercise price	24	20	108

(a) The difference between the market value on the date of exercise and the option exercise price.

The following table summarizes Exelon's nonvested stock option activity for the year ended December 31, 2010:

	Shares	Weighted Average Exercise Price (per share)
Nonvested at December 31, 2009 [(a)]	1,548,855	$60.69
Granted [(b)]	1,019,500	46.09
Vested [(b)]	(1,383,518)	56.44
Forfeited	(242,312)	48.18
Nonvested at December 31, 2010 [(a)]	942,525	$54.35

(a) Excludes 1,209,225 and 1,213,909 of stock options issued to retirement-eligible employees as of December 31, 2010 and December 31, 2009, respectively, as they are fully vested.
(b) Includes 506,200 of stock options issued to retirement-eligible employees in 2010 that vested immediately upon the employee reaching retirement eligibility.

As of December 31, 2010, $7 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 2.24 years.

Restricted Stock Units

Exelon grants restricted stock units under the LTIP. The majority of Exelon's restricted stock units will be settled in common stock. In accordance with the authoritative guidance for share-based payments, the cost of services received from employees in exchange for the issuance of restricted stock units to be settled in stock is required to be measured based on the grant date fair value of the restricted stock unit issued. On a very limited basis, Exelon has granted restricted stock units to certain ComEd executives that will be settled in cash. The obligations related to these restricted stock units have been classified as liabilities on Exelon's Consolidated Balance Sheets and are remeasured each reporting period throughout the requisite service period.

The value of the restricted stock units is expensed over the requisite service period using the straight-line method. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility. The value of the restricted stock units granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted if necessary.

The following table summarizes Exelon's nonvested restricted stock unit activity for the year ended December 31, 2010:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2009 [(a)]	927,942	$63.30
Granted	428,113	44.23
Vested	(375,400)	57.92
Forfeited	(50,079)	61.91
Undistributed vested awards [(b)]	(138,756)	50.10
Nonvested at December 31, 2010 [(a)]	791,820	$57.95

(a) Excludes 233,794, and 211,246 of restricted stock units issued to retirement-eligible employees as of December 31, 2010 and December 31, 2009, respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2010.

The weighted average grant date fair value (per share) of restricted stock units granted during the years ended December 31, 2010, 2009 and 2008 was $44.23, $56.08 and $74.83, respectively. As of December 31, 2010 and 2009, Exelon had obligations related to outstanding restricted stock units not yet settled of $38 million and $42 million, respectively, which are included in common stock in

Exelon's Consolidated Balance Sheets. In addition, Exelon had obligations related to outstanding restricted stock units that will be settled in cash of $1 million at December 31, 2010 and 2009, which are included in deferred credits and other liabilities in Exelon's Consolidated Balance Sheets. During the years ended December 31, 2010, 2009 and 2008, Exelon settled restricted stock units with fair value totaling $22 million, $17 million and $10 million, respectively. As of December 31, 2010, $19 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.07 years.

Performance Share Awards

Exelon grants performance share awards under the LTIP. The number of performance shares granted is determined based on the performance of Exelon's common stock relative to certain stock market indices during the three-year period through the end of the year of grant. These performance share awards generally vest and settle over a three-year period. The holders of performance share awards receive shares of common stock and/or cash annually during the vesting period. Participants are eligible for partial or full distributions in cash if they meet certain stock ownership requirements.

Performance share awards to be settled in stock are recorded as common stock within the Consolidated Balance Sheets and are recorded at fair value at the date of grant. The grant date fair value of equity classified performance share awards granted during the year ended December 31, 2010 was estimated using historical data for the previous two plan years and a Monte Carlo simulation model for the current plan year. This model requires assumptions regarding Exelon's total shareholder return relative to certain stock market indices and the stock beta and volatility of Exelon's common stock and all stocks represented in these indices. Volatility for Exelon and all comparable companies is based on historical volatility over one year using daily stock price observation. Performance share awards expected to be settled in cash are recorded as liabilities within the Consolidated Balance Sheets. The grant date fair value of liability classified performance share awards granted during the year ended December 31, 2010 was based on historical data for the previous two plan years and actual results for the current plan year. The liabilities are remeasured each reporting period throughout the requisite service period and as a result, the compensation costs for cash-settled awards are subject to volatility.

For non retirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method, a method in which the compensation cost is recognized over the requisite service period for each separately vesting tranche of the award as though the award were multiple awards. For performance shares granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period which is the year of grant.

The following table summarizes Exelon's nonvested performance share awards activity for the year ended December 31, 2010:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2009 (a)	630,258	$64.20
Granted	31,587	60.82
Vested	(374,583)	64.26
Forfeited	(3,653)	63.06
Undistributed vested awards (b)	(68,786)	64.47
Nonvested at December 31, 2010 (a)	214,823	$63.51

(a) Excludes 234,419 and 551,558 of performance share awards issued to retirement-eligible employees as of December 31, 2010 and December 31, 2009, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2010.

The weighted average grant date fair value (per share) of performance share awards granted during the years ended December 31, 2010, 2009 and 2008 was $60.82, $57.34 and $72.89, respectively. During the years ended December 31, 2010, 2009 and 2008, Exelon settled performance shares with a fair value totaling $32 million, $47 million and $69 million, respectively, of which $20 million, $30 million and $44 million was paid in cash, respectively. As of December 31, 2010, $2 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.3 years.

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

Obligation Related to Outstanding Performance Share Awards	**As of December 31, 2010**	**2009**
Current liabilities [(a)]	$ 9	$20
Deferred credits and other liabilities [(b)]	4	14
Common stock	16	26
Total	$29	$60

(a) Represents the current liability related to performance share awards expected to be settled in cash.
(b) Represents the long-term liability related to performance share awards expected to be settled in cash.

17. Earnings Per Share and Equity

Earnings per Share

Diluted earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding, including shares to be issued upon exercise of stock options, performance share awards and restricted stock outstanding under Exelon's LTIPs considered to be common stock equivalents. The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	2010	**2009**	**2008**
Income from continuing operations	$2,563	$2,707	$2,717
Income from discontinued operations	—	—	20
Net income	$2,563	$2,707	$2,737
Average common shares outstanding—basic	661	659	658
Assumed exercise and/or distributions of stock-based awards	2	3	4
Average common shares outstanding—diluted	663	662	662

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 8 million in 2010, 5 million in 2009 and less than 1 million in 2008.

18. Commitments and Contingencies

Nuclear Insurance

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of December 31, 2010, the current liability limit per incident was $12.6 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once every 5 years and the last inflation adjustment was made effective October 29, 2008. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. As of January 1, 2011, the amount of nuclear energy liability insurance purchased is $375 million for each operating site. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory participation in a retrospective rating plan for power reactors (currently 104 reactors) resulting in an additional $12.2 billion in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Under the Price-Anderson Act, the maximum assessment in the event of an incident for each nuclear operator, per reactor, per incident (including a 5% surcharge), is $117.5 million, payable at no more than $17.5 million per reactor per incident per year. Exelon's maximum liability per incident is approximately $2.0 billion. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $12.6 billion limit for a single incident.

Generation is required each year to report to the NRC the current levels and sources of insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The insurance maintained for each facility is currently provided through insurance policies purchased from Nuclear Electric Insurance Limited (NEIL), an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all. NEIL declared a distribution for 2010, of which Generation's portion was $20 million. The distribution was recorded as a reduction to operating and maintenance expense within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income. Premiums paid to NEIL by its members are subject to assessment (the retrospective premium obligation) for adverse loss experience. NEIL has never exercised this assessment since its formation in 1973, and while Generation cannot predict the level of future assessments, or if they will be imposed at all, the current maximum aggregate annual retrospective premium obligation for Generation is approximately $212 million.

NEIL provides property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. Generation's current limit for this coverage is $2.1 billion. For property limits in excess of the first $1.25 billion of that limit, Generation participates in an $850 million single limit blanket policy shared by all the Generation operating nuclear sites and the Salem and Hope Creek nuclear sites. This blanket limit is not subject to automatic reinstatement in the event of a loss. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. Generation is unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. Under the terms of the various insurance agreements, Generation could be assessed up to $168 million per year for losses incurred at any plant insured by the insurance company (the retrospective premium obligation). In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery for all losses by all insureds will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses. The $3.2 billion maximum recovery limit is not applicable, however, in the event of a "certified act of terrorism" as defined in the Terrorism Risk Insurance Act of 2002, as amended by the Terrorism Risk Insurance Program Reauthorization Act of 2007. The Terrorism Risk Insurance Act expires on December 31, 2014.

Additionally, NEIL provides replacement power cost insurance in the event of a major accidental outage at an insured nuclear station. The premium for this coverage is subject to assessment for adverse loss experience. Generation's maximum share of any assessment is $44 million per year (the retrospective premium obligation). Recovery under this insurance for terrorist acts is subject to the $3.2 billion aggregate limit and secondary to the property insurance described above. This limit would not apply in cases of certified acts of terrorism under the Terrorism Risk Insurance Act of 2002, as amended by the Terrorism Risk Insurance Program Reauthorization Act of 2007, as described above.

Effective April 1, 2009, NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

In addition, Generation participates in the Master Worker Program, which provides coverage for worker tort claims filed for bodily injury caused by a nuclear energy accident. This program was modified, effective January 1, 1998, to provide coverage to all workers whose "nuclear-related employment" began on or after the commencement date of reactor operations. Generation will not be liable for a retrospective assessment under this policy.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon's and Generation's financial condition, results of operations and liquidity.

Spent Nuclear Fuel Obligation

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from Generation's nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation pays the DOE one mill ($.001) per kWh of net nuclear generation for the cost of SNF disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance will be delayed significantly. In January 2009, the DOE issued its Draft National Transportation Plan for the proposed repository. The DOE's press statement accompanying the release of the plan indicated that shipments to the repository are not expected to begin before 2020.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository while the Obama administration devises a new strategy for long-term SNF management. Debate surrounding any new strategy likely will address centralized interim storage, permanent storage at multiple sites and/or SNF reprocessing. In early 2010, Secretary of Energy Steven Chu appointed the Blue Ribbon Commission on America's Nuclear Future to evaluate and recommend a new plan for managing the back end of the nuclear fuel cycle, including used fuel storage, disposal and fees. John W. Rowe, Exelon's Chairman and Chief Executive Officer, is one of 15 members of the Commission, which is expected to issue a draft report in July 2011.

Given the program's history of funding restrictions, it is likely that shipments to the repository will not begin by 2020. Significant delays in choosing and developing a repository site are expected. Because there is no particular date after 2020 that Generation can establish as having a higher probability as the start date for facility operations, Generation uses the 2020 date as the assumed date for when the DOE will begin accepting SNF for purposes of determining nuclear decommissioning asset retirement obligations. The extended delay in SNF acceptance by the DOE has led to Generation's adoption of dry cask storage at its Dresden, Limerick, Oyster Creek, Peach Bottom, Byron, Braidwood, LaSalle and Quad Cities stations. Generation performed sensitivity analyses assuming that the estimated date for the DOE acceptance of SNF was delayed to 2025 and to 2035 and determined that Generation's aggregate nuclear ARO would be reduced by an immaterial amount in each scenario. In August 2004, Generation and the U.S. DOJ, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse Generation for costs associated with storage of SNF at Generation's nuclear stations pending the DOE's fulfillment of its obligations. Generation submits annual reimbursement requests to the DOE for costs associated with the storage of SNF. In all cases, reimbursement requests are made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

Under the agreement, Generation has received cash reimbursements for costs incurred through April 30, 2010, totaling approximately $461 million ($377 million after considering amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek). As of December 31, 2010, the amount of SNF storage costs for which reimbursement will be requested from the DOE under the settlement agreement is $84 million, which is recorded within accounts receivable, other. Of this amount, $4 million represents amounts owed to the co-owners of the Peach Bottom and Quad Cities generating facilities.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The fee related to the former PECO units has been paid. Pursuant to the Standard Contracts, ComEd previously elected to defer payment of the one-time fee of $277 million for its units (which are now part of Generation), with interest to the date of payment, until just prior to the first delivery of SNF to the DOE. As of December 31, 2010, the unfunded SNF liability for the one-time fee with interest was $1,018 million. Interest accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect, for calculation of the interest accrual at December 31, 2010, was 0.127%. The liabilities for SNF disposal costs, including the one-time fee, were transferred to Generation as part of the 2001 corporate restructuring. The outstanding one-time fee obligations for the Oyster Creek and TMI units remain with the former owners. Clinton has no outstanding obligation. See Note 8—Fair Value of Assets and Liabilities for additional information.

Energy Commitments

Generation's wholesale operations include the physical delivery and marketing of power obtained through its generation capacity, and long-, intermediate- and short-term contracts. Generation maintains a net positive supply of energy and capacity, through ownership of generation assets and power purchase and lease agreements, to protect it from the potential operational failure of one of its owned or contracted power generating units. Generation has also contracted for access to additional generation through bilateral long-term PPAs. These agreements are firm commitments related to power generation of specific generation plants and/or are dispatchable in nature. Several of Generation's long-term PPAs, which have been determined to be operating leases, have significant contingent rental payments that are dependent on the future operating characteristics of the associated plants, such as plant availability. Generation recognizes contingent rental expense when it becomes probable of payment. Generation enters into PPAs with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to its customers.

Generation has also purchased firm transmission rights to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs. The primary intent and business objective for the use of its capital assets and contracts is to provide Generation with physical power supply to enable it to deliver energy to meet customer needs. Generation primarily uses financial contracts in its wholesale marketing activities for hedging purposes. Generation also uses financial contracts to manage the risk surrounding trading for profit activities.

Generation has entered into bilateral long-term contractual obligations for sales of energy to load-serving entities, including electric utilities, municipalities, electric cooperatives and retail load aggregators. Generation also enters into contractual obligations to deliver energy to wholesale market participants who primarily focus on the resale of energy products for delivery. Generation provides delivery of its energy to these customers through rights for firm transmission.

At December 31, 2010, Generation's short- and long-term commitments, relating to the purchase from and sale to unaffiliated utilities and others of energy, capacity and transmission rights, are as indicated in the following tables:

	Net Capacity Purchases (a)	Power Only Purchases (b)	Power Only Sales	Transmission Rights Purchases (c)
2011	$ 291	$ 60	$1,632	$ 9
2012	274	17	758	9
2013	151	—	314	6
2014	147	—	149	—
2015	141	—	150	—
Thereafter	940	—	670	—
Total	$1,944	$ 77	$3,673	$ 24

(a) Net capacity purchases include PPAs and other capacity contracts that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at December 31, 2010. Expected payments include certain capacity charges which are contingent on plant availability.
(b) Excludes renewable energy PPA contracts that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

Pursuant to a PPA with Public Service Company of Oklahoma, a subsidiary of American Electric Power, dated as of April 17, 2009, Generation agreed to sell its rights to up to 520 MW, or approximately two-thirds of the capacity, energy and ancillary services supplied under its existing long-term contract with Green Country Energy, LLC. The delivery of power under the PPA is to commence June 1, 2012 and run through February 28, 2022.

On December 17, 2009, Generation entered into a PPA with Entergy Texas, Inc. (ETI) to sell 150 MWs through April 30, 2011 and 300 MWs thereafter of capacity and energy from the Frontier Generating Station located in Grimes County, Texas. The approximate ten year PPA is not included within the Net Capacity table above because it is contingent upon ETI waiving or obtaining regulatory approvals, which has not yet occurred.

ComEd purchases its expected energy requirements through an ICC approved competitive bidding process administered by the IPA, existing ICC approved RFPs and SFCs, and spot market purchases hedged with a financial swap contract with Generation expiring in 2013. See Note 2—Regulatory Matters for further information.

PECO's long-term PPA with Generation under which PECO obtained all of its electric supply from Generation over the past 12 years expired on December 31, 2010. During 2009 and 2010, PECO entered into procurement contracts through a competitive procurement process in order to meet a portion of its customers' electric supply requirements for 2011 through 2015. As of December 31, 2010, the 2011 expected energy requirements for all customer classes have been substantially procured. PECO will conduct five additional competitive procurements over the remaining term of their DSP Program. See Note 2—Regulatory Matters for further information.

ComEd and PECO are also subject to requirements established by the Illinois Settlement Legislation and the AEPS Act, respectively, related to the use of alternative energy resources. See Note 2—Regulatory Matters for additional information relating to electric generation procurement and alternative energy resources.

ComEd's and PECO's electric supply procurement, REC and AEC purchase commitments as of December 31, 2010 are as follows:

		Expiration within					
	Total	2011	2012	2013	2014	2015	2016 and beyond
ComEd							
Electric supply procurement	$ 252	$ 237	$ 15	$—	$—	$—	$ —
RECs	$ 4	$ 4	$—	$—	$—	$—	$ —
Long-term renewable energy and associated RECs (a)	$1,692	$ —	$ 36	$ 70	$ 72	$ 78	$1,436
PECO							
Electric supply procurement	$2,746	$1,726	$825	$146	$ 25	$ 24	$ —
AECs	$ 49	$ 13	$ 11	$ 7	$ 6	$ 2	$ 10

(a) On December 17, 2010, ComEd entered into 20-year contracts with several unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. See Note 2 of Combined Notes to Consolidated Financial Statements for additional information.

Fuel Purchase Obligations

In addition to the energy commitments described above, Generation has commitments to purchase fuel supplies for nuclear and fossil generation (and with respect to coal, commitments to sell coal) and PECO has commitments to purchase natural gas, related transportation, storage capacity and services to serve customers in their gas distribution service territory. As of December 31, 2010, these net commitments were as follows:

		Expiration within					
	Total	2011	2012	2013	2014	2015	2016 and beyond
Generation	$9,470	$1,281	$1,092	$1,063	$996	$1,103	$3,935
PECO	571	158	92	84	72	52	113

Commercial Commitments

Exelon's commercial commitments as of December 31, 2010, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2011	2012	2013	2014	2015	2016 and beyond
Letters of credit (non-debt) (a)	$ 280	$275	$ 5	$—	$—	$—	$ —
Letters of credit (long-term debt)—interest coverage (b)	3	3	—	—	—	—	—
Surety bonds (c)	72	8	—	—	—	1	63
Performance guarantees (d)	518	—	—	95	200	—	223
Energy marketing contract guarantees (e)	157	111	15	—	—	—	31
Nuclear insurance premiums (f)	2,210	—	—	—	—	—	2,210
Lease guarantees (g)	61	—	1	5	—	—	55
2007 City of Chicago Settlement (h)	3	1	2	—	—	—	—
Midwest Generation Capacity Reservation Agreement guarantee (i)	6	4	2	—	—	—	—
Total commercial commitments	$3,310	$402	$ 25	$100	$200	$ 1	$2,582

(a) Letters of credit (non-debt)—Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties. As of December 31, 2010, guarantees of $1 million have been issued to provide support for certain letters of credit as required by third parties.

(b) Letters of credit (long-term debt) interest coverage—Reflects the interest coverage portion of letters of credit supporting floating-rate pollution control bonds. The principal amounts of the floating-rate pollution control bonds of $191 million at ComEd are reflected in long-term debt in Exelon's Consolidated Balance Sheet.

(c) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

(d) Performance guarantees—Guarantees issued to ensure performance under specific contracts.
(e) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts.
(f) Nuclear insurance premiums—Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.
(g) Lease guarantees—Guarantees issued to ensure payments on building leases.
(h) 2007 City of Chicago Settlement—In December 2007, ComEd entered into an agreement with the City of Chicago. Under the terms of the agreement, ComEd will pay $55 million over six years, of which $52 million was paid through December 31, 2010.
(i) Midwest Generation Capacity Reservation Agreement guarantee—In connection with ComEd's agreement with the City of Chicago entered into on February 20, 2003, Midwest Generation assumed from the City of Chicago a Capacity Reservation Agreement that the City of Chicago had entered into with Calumet Energy Team, LLC. ComEd has agreed to reimburse the City of Chicago for any nonperformance by Midwest Generation under the Capacity Reservation Agreement.

Construction Commitments

Under their operating agreements with PJM, ComEd and PECO are committed to construct transmission facilities to maintain system reliability. ComEd and PECO will work with PJM to continue to evaluate the scope and timing of any required construction projects. ComEd's and PECO's estimated commitments are as follows:

	Total	2011	2012	2013	2014	2015
ComEd	$274	$18	$60	$127	$43	$26
PECO	106	43	28	28	4	3

Leases

Minimum future operating lease payments, including lease payments for vehicles, real estate, computers, rail cars, operating equipment and office equipment, as of December 31, 2010 were:

2011	$ 64
2012	63
2013	56
2014	53
2015	42
Remaining years	400
Total minimum future lease payments	$678 (a)(b)

(a) Excludes Generation's PPAs and other capacity contracts that are accounted for as contingent operating lease payments.
(b) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, Exelon has excluded these payments from the Remaining years, as such amounts would not be meaningful. Exelon's annual obligation for these agreements, included in each of the years 2011-2013, was $2 million and $2 million, and in each of the years 2014-2015 was $2 million and $3 million, respectively.

Exelon's rental expense under operating leases was as follows:

2010	$722 (a)
2009	691 (a)
2008	867 (a)

(a) Includes Generation's PPAs and other capacity contracts that are accounted for as operating leases and are reflected as net capacity purchases in the energy commitments table above. These agreements are considered contingent operating lease payments and are not included in the minimum future operating lease payments table above. Payments made under Generation's PPAs and other capacity contracts totaled $641 million, $616 million and $787 million during 2010, 2009 and 2008, respectively.

For information regarding capital lease obligations, see Note 10—Debt and Credit Agreements.

Indemnifications Related to Sithe

On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe. Specifically, subsidiaries of Generation consummated the acquisition of Reservoir Capital Group's 50% interest in Sithe and subsequently sold 100% of Sithe to Dynegy, Inc. (Dynegy).

In connection with the sale, Generation recorded liabilities related to certain indemnifications provided to Dynegy and other guarantees directly resulting from the transaction. Any activity related to Sithe recorded in Exelon's Consolidated Statements of Operations and Comprehensive Income is recorded as discontinued operations. During 2008, Generation reduced its guarantee liabilities and recognized $38 million of income in discontinued operations related to the expiration of tax indemnifications. As of December 31, 2010, Generation had $6 million in recorded guarantee obligations remaining. The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy was approximately $200 million at December 31, 2010.

Indemnifications Related to Sale of TEG and TEP

On February 9, 2007, Tamuin International Inc. (TII), a wholly owned subsidiary of Generation, sold its 49.5% ownership interests in TEG and TEP to a subsidiary of AES Corporation for $95 million in cash plus certain purchase price adjustments. In connection with the transaction, Generation entered into a guarantee agreement under which Generation guarantees the timely payment of TII's obligations to the subsidiary of AES Corporation pursuant to the terms of the purchase and sale agreement relating to the sale of TII's ownership interests. Generation would be required to perform in the event that TII does not pay any obligation covered by the guarantee that is not otherwise subject to a dispute resolution process. Generation's maximum obligation under the guarantee is $95 million. Generation has not recorded a liability associated with this guarantee. The exposures covered by this guarantee expired in part during 2008. Generation expects that the remaining exposure will expire by 2014.

Environmental Issues

General. The Registrants' operations have in the past and may in the future require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

ComEd and PECO have identified 42 and 27 sites, respectively, where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, ComEd or PECO is one of several PRPs that may be responsible for ultimate remediation of each location. Of the 42 sites identified by ComEd, the Illinois EPA or U.S. EPA have approved the cleanup of 12 sites and of the 27 sites identified by PECO, the PA DEP has approved the cleanup of 16 sites. Of the remaining sites identified by ComEd and PECO, 24 and 9 sites, respectively, are currently under some degree of active study and/or remediation. ComEd and PECO anticipate that the majority of the remediation at these sites will continue through at least 2015 and 2018, respectively.

In January 2008, ComEd and Nicor Gas Company, a subsidiary of Nicor Inc. (Nicor), reached a settlement agreement on the allocation of costs for the 38 former MGP sites for which ComEd or Nicor, or both, have responsibility. This agreement was approved by the ICC on June 9, 2009. The approval of the settlement by the ICC did not have an impact on ComEd's cash flows or results of operations.

During the third quarter of 2010, ComEd and PECO each completed an annual study of their future estimated MGP remediation requirements. The results of these studies indicated that additional remediation would be required at certain sites; accordingly, ComEd and PECO increased their reserves and regulatory assets by $13 million and $2 million, respectively. Pursuant to orders from the ICC and PAPUC, respectively, ComEd and PECO are authorized to and are currently recovering environmental costs for the remediation of former MGP facility sites from customers, for which they have recorded regulatory assets. PECO's 2010 approved natural gas distribution rate case settlement increased the annual MGP recovery to be collected from customers beginning January 2011. See Note 2—Regulatory Matters for additional information.

As of December 31, 2010 and 2009, Exelon had accrued the following undiscounted amounts for environmental liabilities in other deferred credits and other liabilities within their Consolidated Balance Sheets:

	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
2010	$179	$156
2009	$175	$149

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

Section 316(b) of the Clean Water Act. In July 2004, the U.S. EPA issued the final Phase II rule implementing Section 316(b) of the Clean Water Act. The Clean Water Act requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts. The Phase II rule provided each facility with a number of compliance options and permitted site-specific variances based on a cost-benefit analysis. The requirements were intended to be implemented through state-level NPDES permit programs. All of Generation's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected. Those facilities are Clinton, Cromby, Dresden, Eddystone, Fairless Hills, Handley, Mountain Creek, Oyster Creek, Peach Bottom, Quad Cities, Salem and Schuylkill.

In a 2007 decision, the U.S. Second Circuit Court of Appeals remanded the Phase II rule back to the U.S. EPA for revisions. The court found that with respect to a number of significant provisions of the rule the EPA exceeded its authority under the Clean Water Act, failed to adequately set forth its rationale for the rule, or failed to follow required procedures for public notice and comment. By its action, the court invalidated compliance measures which were supported by the utility industry because they were cost-effective and provided existing plants with needed flexibility in selecting the compliance option appropriate to its location and operations. On July 9, 2007, the EPA formally suspended the Phase II rule.

In April 2009, the U.S. Supreme Court reversed the decision of the U.S. Second Circuit Court of Appeals in one respect, and determined that the EPA could use a cost-benefit analysis under Section 316(b) to determine the best technology available for minimizing adverse environmental impact at cooling water intake structures. The U.S. EPA is considering the rule on remand and will take further action consistent with the opinions of the Supreme Court and the Court of Appeals, including whether to exercise its discretion to retain or modify the cost-benefit rule as it appeared in the initial regulation. In November 2010, the EPA reached a settlement with the plaintiffs in the Section 316(b) litigation that requires the EPA to issue a proposed rule by March 14, 2011, and to publish a final rule by July 27, 2012. Until then, the state permitting agencies will continue the current practice of applying their best professional judgment to address impingement and entrainment requirements at plant cooling water intake structures. The Courts' opinions have created uncertainty about the specific nature, scope and timing of the final compliance requirements.

On January 7, 2010, the NJDEP issued a draft NPDES permit for Oyster Creek that would have required, in the exercise of its best professional judgment, the installation of cooling towers as the best technology available within seven years after the effective date of the permit. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. The current NRC license for Oyster Creek expires in 2029. In reliance upon Exelon's determination to cease generation operations no later than December 31, 2019, the NJDEP determined that closed cycle cooling is not the best technology available for Oyster Creek given the length of time that would be required to retrofit from the existing once-through cooling system to a closed-cycle cooling system and the limited life span of the plant after installation of a closed-cycle cooling system. Based on its consideration of these and other factors, in its best professional judgment, NJDEP determined that the existing measures at the plant represent the best technology available for the facility's cooling water intake system.

On December 9, 2010, Generation executed an Administrative Consent Order (ACO) with the NJDEP regarding Oyster Creek. The ACO sets forth, among other things, the agreement by Generation to permanently cease generation operations at Oyster Creek if the conditions of the ACO are satisfied. In the ACO, the NJDEP agreed to issue a new draft NPDES permit without a requirement for construction of cooling towers or other closed cycle cooling facilities. It is expected that a draft NPDES permit will be issued and will become final and effective sometime in 2011. The ACO applies only to Oyster Creek based on its unique circumstances and does not set any precedent for the ultimate compliance requirements for Section 316(b) at Exelon's other plants.

As a result of the decision and the ACO, the expected economic useful life of Oyster Creek has been reduced. The financial impacts, which are not expected to be material to Generation's results of operations, will relate primarily to accelerated depreciation and accretion expense associated with the changes in decommissioning assumptions related to Generation's asset retirement obligation over the remaining expected economic useful life of Oyster Creek. As a result of the announcement to close Oyster Creek by 2019, Generation's operating expenses increased by $7 million (pre-tax) in 2010 and are estimated to increase approximately $25-$30 million (pre-tax) in each of the years 2011 through 2015. The impacts to Generation's operating expenses in years 2016 through 2019 will be dependent on future capital spending at Oyster Creek. Generation will also make employee retention payments of approximately $20 million in 2011 that are expected to increase operating expenses by approximately $4 million (pre-tax) in each of the years 2011 through 2015.

In June 2001, the NJDEP issued a renewed NPDES permit for Salem, allowing for the continued operation of Salem with its existing cooling water system. NJDEP advised PSEG in July 2004 that it strongly recommended reducing cooling water intake flow commensurate with closed-cycle cooling as a compliance option for Salem. PSEG submitted an application for a renewal of the permit on February 1, 2006. In the permit renewal application, PSEG analyzed closed-cycle cooling and other options and demonstrated that the continuation of the Estuary Enhancement Program, an extensive environmental restoration program at Salem, is the best technology to meet the Section 316(b) requirements. PSEG continues to operate Salem under the approved June 2001 NPDES permit while the NPDES permit renewal application is being reviewed. If the final permit or Section 316(b) regulations ultimately requires the retrofitting of Salem's cooling water intake structure to reduce cooling water intake flow commensurate with closed-cycle cooling, Exelon's and Generation's share of the total cost of the retrofit and any resulting interim replacement power would likely be in excess of $500 million, based on a 2006 estimate, and would result in increased depreciation expense related to the retrofit investment.

It is unknown at this time whether the final regulations or permit will require closed-cycle cooling at Salem. In addition, the economic viability of Generation's other power generation facilities without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Given the uncertainties associated with these proceedings and the time required for their resolution, Generation cannot predict the eventual outcome of the proceedings or estimate the effect that compliance with any resulting Section 316(b) or interim state requirements will have on the operation of its generating facilities and its future results of operations, cash flows and financial position.

Cotter Corporation. The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. Cotter is alleged to have disposed of approximately 39,000 tons of soils mixed with 8,700 tons of leached barium sulfate at the site. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. The current estimated cost of the anticipated landfill cover remediation for the site is approximately $40 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve excavation of the radiological contamination. An excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require the use of an excavation remedy is remote.

Air. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the CAIR, which had been promulgated by the U.S. EPA to reduce power plant emissions of SO_2 and NO_x. The Court later remanded the CAIR to the U.S. EPA, without invalidating the entire rulemaking, so that the U.S. EPA could correct CAIR in accordance with the Court's July 11, 2008 opinion. On July 6, 2010, the U.S. EPA published the proposed Transport Rule as the replacement to the CAIR. The first phase of the NO_x and SO_2 emissions reductions under the proposed Transport Rule regulations will commence in 2012, with further reductions of SO_2 emissions proposed to become effective in 2014. Given its low carbon generation portfolio, Generation does not currently expect the adoption of the rules as proposed to have a significant impact on its future capital spending requirements. These emissions limits will be further reduced as the U.S. EPA finalizes more restrictive NAAQS in the 2011-2012 timeframe.

The proposed Transport Rule regulations also would limit the use of allowance trading to achieve compliance and restrict entirely the use of pre-2012 allowances. Existing SO2 allowances under the ARP would remain available for use under ARP. During the third quarter of 2010, Generation recognized a lower of cost or market impairment charge of $57 million on its ARP SO_2 allowances that are not expected to be used by Generation's fossil-fuel power plants and that have not been sold forward. The impairment was recorded due to the significant decline of allowance market prices because proposed Transport Rule regulations would restrict entirely the use of ARP SO_2 allowances beginning in 2012. As of December 31, 2010, Generation had $10 million of emission allowances carried at the lower of weighted average cost or market.

Additionally, as of December 31, 2010, Exelon has a $629 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases extending through 2028-2032. While Exelon currently estimates the value of these plants at the end of the lease term will be in excess of the recorded residual lease values, the ultimate passage of the proposed Transport Rule could negatively impact the end-of-lease term values of these assets, which could result in a future impairment loss that could be material.

In March 2005, the U.S. EPA finalized the CAMR, which was a national program to cap mercury emissions from fossil-fired generating units starting in 2010, with a second reduction in the mercury emission cap level scheduled for 2018. The D.C. Circuit Court later vacated the CAMR on the basis that the U.S. EPA had failed to properly de-list mercury as a HAP under Section 112(c)(1) of the Clean Air Act. The result of this decision is that mercury emissions from electric generating stations are subject to the more stringent requirements of maximum achievable control technology applicable to HAPs. In resolution of the CAMR litigation, the U.S. EPA entered into a Consent Decree that requires it to propose by March 16, 2011 HAP regulations for emissions from fossil generating stations, and to publish final HAP regulations by November 15, 2011. The nature and extent of future regulatory controls on HAP emissions at electric generation power plants will not be determined until the Federal regulations are finalized by the U.S. EPA.

The U.S. EPA has announced that it will complete a review of NAAQS in the 2011-2012 timeframe for ozone (nitrogen oxide and volatile organic chemicals), particulate matter, nitrogen dioxide, sulfur dioxide, and lead. This review could result in more stringent emissions limits on fossil-fired electric generating stations.

Climate Change Regulation. Exelon is subject to climate change regulation or legislation at the international, Federal, regional and state levels. In 2007, the U.S. Supreme Court ruled that GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. Consequently, on December 7, 2009, the U.S. EPA issued an endangerment finding under Section 202 of the Clean Air Act regarding GHGs from new motor vehicles and on April 1, 2010 issued final regulations limiting GHG emissions from cars and light trucks effective on January 2, 2011. While such regulations do not specifically address stationary sources, such as a generating plant, it is the U.S. EPA's position that the regulation of GHGs under the mobile source provisions of the Clean Air Act has triggered the permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources effective January 2, 2011. Therefore, on May 13, 2010, the U.S. EPA issued final regulations relating to these provisions of the Clean Air Act for major stationary sources of GHG emissions that apply to new sources that emit greater than 100,000 tons per year, on a CO_2 equivalent basis, and to modifications to existing sources that result in emissions increases greater than 75,000 tons per year on a CO_2 equivalent basis. These thresholds became effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. Under the regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case-by-case basis. Exelon could be significantly affected by the regulations if it were to build new plants or modify existing plants.

Notices and Finding of Violations Related to Electric Generation Stations. On August 6, 2007, ComEd received an NOV, addressed to it and Midwest Generation, LLC (Midwest Generation) from the U.S. EPA, alleging that ComEd and Midwest Generation have violated and are continuing to violate several provisions of the Clean Air Act as a result of the modification and/or operation of six electric generation stations located in northern Illinois that have been owned and operated by Midwest Generation since 1999. The U.S. EPA requested information related to the stations in 2003, and ComEd has been cooperating with the U.S. EPA since then. The NOV states that the U.S. EPA may issue an order requiring compliance with the relevant Clean Air Act provisions and may seek injunctive relief and/or civil penalties, all pursuant to the U.S. EPA's enforcement authority under the Clean Air Act.

The generating stations that are the subject of the NOV are currently owned and operated by Midwest Generation, which purchased the stations in December 1999 from ComEd. Under the terms of the sale agreement, Midwest Generation and its affiliate, Edison Mission Energy (EME), assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance of the stations with environmental laws before the purchase of the stations by Midwest Generation. Midwest Generation and EME additionally agreed to indemnify and hold ComEd and its affiliates harmless from claims, fines, penalties, liabilities and expenses arising from third party claims against ComEd resulting from or arising out of the environmental liabilities assumed by Midwest Generation and EME under the terms of the agreement governing the sale.

In August 2009, the DOJ and the Illinois Attorney General filed a complaint against Midwest Generation with the U.S. District Court for the Northern District of Illinois initiating enforcement proceedings with respect to the alleged Clean Air Act violations set forth in the NOV. Neither ComEd nor Exelon were named as a defendant in this original complaint. In March 2010, the District Court granted Midwest Generation's partial motion to dismiss all but one of the claims against Midwest Generation. The Court held that Midwest Generation cannot be liable for any alleged violations relating to construction that occurred prior to Midwest Generation's ownership of the stations. In May 2010, the government plaintiffs filed an amended complaint substantially similar to the original complaint, and added ComEd and EME as defendants. The amended complaint seeks injunctive relief and civil penalties against all defendants, although not all of the claims specifically pertain to ComEd. On September 17, 2010, ComEd filed a motion requesting the Court to dismiss the governmental plaintiffs' amended complaint. On November 16, 2010, the government filed its response to ComEd's motion to dismiss, and ComEd filed its reply to the government's response on December 17, 2010. The Court has not yet ruled on that motion.

In connection with Exelon's 2001 corporate restructuring, Generation assumed ComEd's rights and obligations with respect to its former generation business. Exelon, Generation and ComEd are unable to predict the ultimate resolution of the claims alleged in the amended complaint, the costs that might be incurred or the amount of indemnity that may be available from Midwest Generation and EME; however, Exelon, Generation and ComEd have concluded that, while a loss may be reasonably possible, they believe the likelihood of loss is not probable. Therefore, no reserve has been established. Further, Generation believes that it would be reimbursed for any losses under the terms of the indemnification agreement, subject to the credit worthiness of Midwest Generation and EME. Exelon, Generation and ComEd cannot predict an estimated amount or range of possible loss.

Litigation and Regulatory Matters

Real Estate Tax Appeals. On January 19, 2010, Generation appealed to the LaSalle County Board of Review the real estate tax assessment for the 2009 tax year concerning the value of its LaSalle Generating Station (LaSalle County, Illinois)(LaSalle), and on December 6, 2010, Generation appealed the real estate tax assessment for LaSalle for the 2010 tax year. Generation recorded the assessed real estate taxes as of December 31, 2010 and 2009 and paid the 2009 taxes, as assessed, to the taxing authorities. The appeal for LaSalle for the 2009 tax year continues at the Illinois Property Tax Appeal Board. Generation does not anticipate a decision in the 2009 tax appeal for several years due to backlog at the Appeal Board. The ultimate outcome of both of these matters is uncertain and it is reasonably possible that the outcome could result in unfavorable or favorable impacts to the consolidated financial statements of Exelon and Generation.

Asbestos Personal Injury Claims. Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The reserve is recorded on an undiscounted basis and excludes the estimated legal costs associated with handling these matters, which could be material.

At December 31, 2010 and 2009, Generation had reserved approximately $53 million and $49 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2010, approximately $16 million of this amount related to 181 open claims presented to Generation, while the remaining $37 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050 based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary. During 2010, 2009 and 2008, the updates to this reserve, including the extension of future claims to be considered from 2030 to 2050 in the second quarter of 2008, did not result in material adjustments.

Pension Claims. On July 11, 2006, a former employee of ComEd filed a purported class action lawsuit against the Exelon Corporation Cash Balance Pension Plan (Plan) in the U.S. District Court for the Northern District of Illinois. The complaint alleged that the Plan, which covers certain management employees of Exelon's subsidiaries, calculated lump sum distributions in a manner that does not comply with ERISA. The plaintiff sought compensatory relief from the Plan on behalf of participants who received lump sum distributions between 2001 and 2006 and injunctive relief with respect to future lump sum distributions. The District Court dismissed the lawsuit but allowed the plaintiff to file an administrative claim with the Plan with respect to the calculation of the portion of his lump sum benefit accrued under the Plan's prior traditional formula. On July 2, 2009, the U.S. Court of Appeals for the Seventh Circuit affirmed the District Court's ruling, and the plaintiff's subsequent motion requesting rehearing of the case before the entire Seventh Circuit Court of Appeals was denied. On October 28, 2009, the plaintiff filed a petition requesting that the U.S. Supreme Court hear an appeal of the Seventh Circuit's decision. On February 22, 2010, the U.S. Supreme Court declined to hear the appeal. In addition, on January 6, 2009, the plaintiff filed a complaint in the District Court challenging the Plan's denial of his administrative claim, and on November 12, 2010, the District Court granted the Plan's motion for summary judgment and dismissed the plaintiff's remaining claims with prejudice. The plaintiff did not appeal the dismissal of his remaining claims.

Savings Plan Claim. On September 11, 2006, five individuals claiming to be participants in the Exelon Corporation Employee Savings Plan, Plan #003 (Savings Plan), filed a putative class action lawsuit in the U.S. District Court for the Northern District of Illinois. The complaint names as defendants Exelon, its Director of Employee Benefit Plans and Programs, the Employee Savings Plan Investment Committee, the Compensation and the Risk Oversight Committees of Exelon's Board of Directors and members of those committees. The complaint alleged that the defendants breached fiduciary duties under ERISA by, among other things, permitting fees and expenses to be incurred by the Savings Plan that allegedly were unreasonable and for purposes other than to benefit the Savings Plan and participants, and failing to disclose purported "revenue sharing" arrangements among the Savings Plan's service providers. The plaintiffs sought declaratory, equitable and monetary relief on behalf of the Savings Plan and participants, including alleged investment losses. On August 19, 2009, the plaintiffs in the Exelon case filed an amended complaint in the District Court, which again alleged that defendants breached fiduciary duties under ERISA by, among other things, permitting the Savings Plan to pay excessive fees and expenses for administrative services, but eliminated the claim for investment losses and the allegations regarding "revenue sharing." On December 9, 2009, the District Court granted the defendants' motion to dismiss the amended complaint and enter judgment in favor of the defendants. The plaintiffs have appealed the District Court's dismissal of their claims to the U.S. Court of Appeals for the Seventh Circuit, where the matter remains pending. The ultimate outcome of the savings plan claim is uncertain and may have a material impact on Exelon's results of operations, cash flows or financial position.

General. The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The Registrants maintain accruals for such costs that are probable of being incurred and subject to reasonable estimation. The Registrants will record a receivable if they expect to recover costs for these contingencies. The ultimate outcomes of such matters, as well as the matters discussed above, are uncertain and may have a material adverse impact on the Registrants' results of operations, cash flows or financial positions.

Fund Transfer Restrictions

Under applicable law, Exelon may borrow or receive an extension of credit from its subsidiaries. Under the terms of Exelon's intercompany money pool agreement, Exelon can lend to, but not borrow from the money pool.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." What constitutes "funds properly included in capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon's actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with financings arranged through ComEd Financing III that it will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued.

PECO's Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. At December 31, 2010, such capital was $2.9 billion and amounted to about 33 times the liquidating value of the outstanding preferred securities of $87 million. Additionally, PECO may not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued.

Income Taxes

See Note 11—Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

19. Supplemental Financial Information

Supplemental Income Statement Information

The following tables provide additional information about Exelon's Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2010, 2009 and 2008.

	For the Year Ended December 31,		
	2010	**2009**	**2008**
Operating revenues [(a)]			
Wholesale	$ 5,934	$ 5,469	$ 6,394
Retail electric and gas	11,906 [(b)]	11,099 [(b)]	11,816 [(b)]
Other	804 [(c)]	750 [(c)]	649 [(c)]
Total operating revenues	$18,644	$17,318	$18,859

(a) Includes operating revenues from affiliates.
(b) Generation's retail electric and gas operating revenues consist primarily of Exelon Energy Company, LLC. Generation's retail electric operating revenues are allocated among its reportable segments.
(c) Includes amounts recorded related to the Illinois Settlement Legislation.

	For the Year Ended December 31,		
	2010	**2009**	**2008**
Depreciation, amortization and accretion			
Property, plant and equipment	$1,144	$ 996	$ 898
Regulatory assets [(a)]	931	838	736
Nuclear fuel [(b)]	672	558	448
ARO accretion [(c)]	196	209	226
Total depreciation, amortization and accretion	$2,943	$2,601	$2,308

(a) For PECO, primarily reflects CTC amortization.
(b) Included in fuel expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(c) Included in operating and maintenance expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

	For the Year Ended December 31,		
	2010	**2009**	**2008**
Taxes other than income			
Utility [(a)]	$476	$481	$507
Real estate [(b)]	175	157	127
Payroll	121	114	123
Other	36	26	21
Total taxes other than income	$808	$778	$778

(a) Municipal and state utility taxes are also recorded in revenues on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(b) PECO reflected amortization of the regulatory liability recorded in connection with the 2007 PURTA settlement, partially offset by current year property taxes.

	For the Year Ended December 31,		
	2010	2009	2008
Loss in equity method investments			
Financing trusts	$—	$(24)	$(25)
NuStart Energy Development, LLC	—	(3)	(1)
Total loss in equity method investments	$—	$(27)	$(26)

	For the Year Ended December 31,		
	2010	2009	2008
Other, Net			
Decommissioning-related activities:			
Net realized income on decommissioning trust funds—Regulatory Agreement Units [(a)]	$ 176	$ 126	$ 43
Net realized income on decommissioning trust funds—Non-Regulatory Agreement Units [(a)]	51	29	16
Net unrealized gains (losses) on decommissioning trust funds—Regulatory Agreement Units	316	801	(1,022)
Net unrealized gains (losses) on decommissioning trust funds—Non-Regulatory Agreement Units	104	227	(324)
Regulatory offset to decommissioning trust fund-related activities [(b)]	(394)	(746)	777
Total decommissioning-related activities	253	437	(510)
Investment income	1	5	10
Long-term lease income	27	26	24
Interest income related to uncertain income tax positions [(c)]	—	50	31
Realized gains on Rabbi trust investments	1	5	—
Other-than-temporary impairment to Rabbi trust investments [(d)]	—	(7)	—
Losses on early retirement of debt	—	(117)	—
Income related to the termination of a gas supply guarantee	—	—	13
Other	30	28	25
Other, net	$ 312	$ 427	$ (407)

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.

(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 12—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(c) Primarily includes interest income at ComEd from the 2009 re-measurement of income tax uncertainties. See Note 11—Income Taxes for additional information.

(d) ComEd recorded an other-than-temporary impairment to Rabbi trust investments during 2009.

Supplemental Cash Flow Information

The following tables provide additional information regarding Exelon's Consolidated Statements of Cash Flows for the years ended December 31, 2010, 2009 and 2008.

For the Year Ended December 31, 2010	
Cash paid (refunded) during the year	
Interest (net of amount capitalized)	$ 625 [a]
Income taxes (net of refunds)	1,219
Other non-cash operating activities:	
Pension and non-pension postretirement benefits costs	$ 581
Provision for uncollectible accounts	108
Provision for obsolete inventory	12
Stock-based compensation costs	44
Other decommissioning-related activity [b]	(91)
Energy-related options [c]	(73)
ARO adjustment	(19)
Amortization of regulatory asset related to debt costs	24
Accrual for Illinois utility distribution tax refund [d]	(25)
Under-recovered uncollectible accounts, net [e]	(14)
ARP SO2 allowances impairment	57
Other	5
Total other non-cash operating activities	$ 609
Changes in other assets and liabilities:	
Under/over-recovered energy and transmission costs	61
Other current assets	(18)
Other noncurrent assets and liabilities	(99) [f]
Total changes in other assets and liabilities	$ (56)

For the Year Ended December 31, 2010

Non-cash investing and financing activities

Change in ARC	$(428)
Capital expenditures not paid	34
Purchase accounting adjustments	9
Exelon Wind acquisition (g)	32

(a) Excludes $167 million of interest paid to the IRS relating to a preliminary agreement reached during the third quarter of 2010. See Note 11—Income Taxes for additional information.

(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 12—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(c) Includes amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of underlying transactions.

(d) During the second quarter of 2010, ComEd recorded a reduction of $25 million to taxes other than income to reflect management's estimate of future refunds for the 2008 and 2009 tax years associated with Illinois' utility distribution tax based on an analysis of past refunds and interpretations of the Illinois Public Utility Act. Historically, ComEd has recorded refunds of the Illinois utility distribution tax when received. ComEd believes it now has sufficient, reliable evidence to record and support an estimated receivable associated with the anticipated refund for the 2008 and 2009 tax years.

(e) Includes $70 million of under-recovered uncollectible accounts expense from 2008 and 2009 recorded in the first quarter of 2010 as well as $59 million of amortization of the associated regulatory asset. This amount also includes a credit of $3 million of undercollections associated with 2010 activity. ComEd is recovering these costs through a rider mechanism authorized by the ICC. See Note 2—Regulatory Matters for additional information regarding the Illinois legislation for recovery of uncollectible accounts.

(f) Relates primarily to a decrease in interest payable associated with a change in uncertain income tax positions. See Note 11—Income Taxes for additional information.

(g) Represents contingent liability recorded in connection with the December 9, 2010 acquisition of Exelon Wind. See Note 3—Acquisition for additional information.

For the Year Ended December 31, 2009

Cash paid (refunded) during the year	
Interest (net of amount capitalized)	$ 647
Income taxes (net of refunds)	982
Other non-cash operating activities:	
Pension and non-pension postretirement benefits costs	$ 536
Loss in equity method investments	27
Provision for uncollectible accounts	149
Stock-based compensation costs	70
Other decommissioning-related activity [(a)]	(163)
Energy-related options [(b)]	46
ARO adjustment [(c)]	(47)
Amortization of regulatory asset related to debt costs	25
Amortization of the regulatory liability related to the PURTA tax settlement	(2)
Other-than-temporary impairment to Rabbi trust investments [(d)]	7
Inventory write-down related to plant retirements	17
Other	(13)
Total other non-cash operating activities	$ 652
Changes in other assets and liabilities:	
Under/over-recovered energy and transmission costs	$ 23
Other current assets	(2)
Other noncurrent assets and liabilities	(134) [(e)]
Total changes in other assets and liabilities	$(113)
Non-cash investing and financing activities	
Change in ARC	$ 67
Capital expenditures not paid	70
Purchase accounting adjustments	9

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 12—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(b) Includes amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of underlying transactions.

(c) Represents the reduction in the ARO in excess of the existing ARC balances for Generation's nuclear generating units that are not subject to regulatory agreement with respect to decommissioning trust funding (the former AmerGen units and the portions of the Peach Bottom units).

(d) ComEd recorded an other-than-temporary impairment to Rabbi trust investments during the second quarter of 2009. See Note 8—Fair Value of Assets and Liabilities for additional information regarding the impairment.

(e) Relates primarily to a decrease in interest payable associated with the remeasurement of uncertain income tax positions. See Note 11—Income Taxes for additional information.

For the Year Ended December 31, 2008

Cash paid (refunded) during the year	
Interest (net of amount capitalized)	$ 716
Income taxes (net of refunds)	938
Other non-cash operating activities:	
Pension and non-pension postretirement benefits costs	$ 314
Loss in equity method investments	26
Provision for uncollectible accounts	247
Stock-based compensation costs	67
Other decommissioning-related activity [(a)]	219
Energy-related options [(b)]	5
Amortization of regulatory liability related to debt costs	25
Amortization of the regulatory liability related to the PURTA tax settlement [(c)]	(36)
Net impact of the 2007 distribution rate case order [(d)]	22
Reduction of guarantees [(e)]	(55)
Other	36
Total other non-cash operating activities	$ 870
Changes in other assets and liabilities:	
Under/over-recovered energy and transmission costs	$ 32
Other current assets	12
Other noncurrent assets and liabilities	(179)
Total changes in other assets and liabilities	$(135)
Non-cash investing and financing activities	
Change in ARC	$ 128
Capital expenditures not paid	23
Purchase accounting adjustments	10

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 12—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of underlying transactions.
(c) In March 2007, PECO prevailed in a Pennsylvania Supreme Court case in which PECO had contested the assessment of PURTA taxes applicable to 1997. As a result, PECO received approximately $38 million of real estate taxes previously remitted. This refund was recorded as a regulatory liability and PECO began amortizing this liability and refunding customers in January 2008.
(d) In September 2008, as a result of the 2007 Rate Case order, ComEd recorded $37 million of fixed asset disallowances; $35 million was recorded as operating and maintenance expense and $2 million was recorded as depreciation expense. In addition, ComEd established regulatory assets totaling approximately $13 million associated with reversing previously incurred expenses deemed recoverable in future rates. See Note 2—Regulatory Matters for more information.
(e) Includes reversal of Sithe guarantee of $38 million and Distrigas guarantee of $13 million.

DOE Smart Grid Investment Grant. For the year ended December 31, 2010, Exelon and PECO have included in the capital expenditures line item in investing activities of the cash flow statement capital expenditures of $28 million related to PECO's DOE SGIG. See Note 2—Regulatory Matters for additional information regarding the accounting for the DOE SGIG.

Repurchase Agreements. Repurchase Agreements are financial instruments used to fund short-term liquidity requirements where a counterparty typically agrees to sell the financial instrument and repurchase it the following day. Exelon and Generation have historically presented purchases and sales of Repurchase Agreements with a maturity of three months or less on a gross basis in 'Investments in NDT funds and 'Proceeds from NDT fund sales', respectively, within Exelon and Generation's Consolidated Statement of Cash Flows. Due to the nature and volume of these transactions, effective December 31, 2010, Exelon and Generation have included the cash flows associated with the purchase and sale of Repurchase Agreements with a maturity of three months or less on a net basis in 'Proceeds from NDT fund sales' within their Consolidated Statement of Cash Flows. Cash flows associated with all other NDT funds investments will continue to be presented on a gross basis. The years ended December 31, 2009 and 2008 were adjusted to reflect this change in presentation, which is presented in the following table:

	Year Ended December 31, 2009		
	As previously stated	Adjustments	As Adjusted
Proceeds from NDT fund sales	$ 22,905	$(18,613)	$ 4,292
Investments in NDT funds	$(23,144)	$ 18,613	$ (4,531)

	Year Ended December 31, 2008		
	As previously stated	Adjustments	As Adjusted
Proceeds from NDT fund sales	$ 17,202	$ (6,545)	$ 10,657
Investments in NDT funds	$(17,487)	$ 6,545	$(10,942)

Supplemental Balance Sheet Information

The following tables provide additional information about Exelon's assets and liabilities as of December 31, 2010 and 2009.

	December 31,	
	2010	2009
Investments		
Equity method investments:		
Financing trusts [(a)]	$ 15	$ 20
Keystone Fuels, LLC	10	15
Conemaugh Fuels, LLC	13	19
NuStart Energy Development, LLC	1	1
Total equity method investments	39	55
Other investments:		
Net investment in direct financing leases	629	602
Employee benefit trusts and investments [(b)]	64	67
Total investments	$732	$724

(a) Includes investments in financing trusts which were not consolidated within the financial statements of Exelon. See Note 1—Significant Accounting Policies for additional information.
(b) Exelon's investments in these marketable securities are recorded at fair market value.

December 2010 IRS Payment. In the third quarter of 2010, Exelon and IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions. In order to stop additional interest from accruing on the expected assessment resulting from the agreement, Exelon paid $302 million to the IRS on December 28, 2010. As of December 31, 2010, Exelon had not funded the specific bank account from which the IRS payment was disbursed resulting in a current liability. This amount was subsequently funded in January 2011. Under the authoritative guidance for offsetting balances, Exelon included this payment in Cash and cash equivalents with an offsetting amount in Other current liabilities on its Consolidated Balance Sheets. See Note 11—Income Taxes for additional information.

Like-Kind Exchange Transaction. Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in passive generating station leases with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. For financial accounting purposes, the investments are accounted for as direct financing lease investments. UII holds the leasehold interests in the generating stations in several separate bankruptcy remote, special purpose companies it directly or indirectly wholly owns. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to require the lessees to return the leasehold interests or to arrange a service contract with a third party for a period following the lease term. If Exelon chooses the service contract option, the leasehold interests will be returned to Exelon at the end of the term of the service contract. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. In the fourth quarter of 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases. As of December 31, 2010 and 2009, the components of the net investment in long-term leases were as follows:

	December 31, 2010	December 31, 2009
Estimated residual value of leased assets	$1,492	$1,492
Less: unearned income	863	890
Net investment in long-term leases	$ 629	$ 602

The following tables provide additional information about Exelon's liabilities at December 31, 2010 and 2009.

	December 31, 2010	December 31, 2009
Accrued expenses		
Compensation-related accruals [(a)]	$ 465	$401
Taxes accrued	297	264
Interest accrued	195	170
Severance accrued	22	36
Other accrued expenses	61	52
Total accrued expenses	$1,040	$923

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.

The following tables provide information about accumulated other comprehensive loss recorded (after tax) within Exelon's Consolidated Balance Sheets as of December 31, 2010 and 2009:

	December 31, 2010	December 31, 2009
Accumulated other comprehensive loss		
Net unrealized gain on cash flow hedges	$ 400	$ 551
Pension and non-pension postretirement benefit plans	(2,823)	(2,640)
Total accumulated other comprehensive loss	$(2,423)	$(2,089)

20. Segment Information

During the first quarter of 2010, Exelon concluded that Generation no longer operates as a single reportable segment, primarily due to a change in the financial information regularly evaluated by the chief operating decision maker (CODM) in determining resource allocation and assessing performance. Certain regional results of Generation's power marketing activities are now being provided to the CODM and in other public disclosures. As a result, Generation had three reportable segments, the Mid-Atlantic, Midwest, and South, representing the different geographical areas in which Generation's power marketing activities are conducted. As a result of the acquisition of Exelon Wind during the fourth quarter of 2010, Generation adjusted its South reportable segment to include recently acquired assets located in the South and West geographical areas, forming the South and West reportable segment. In addition, the Exelon Wind assets located in the Midwest geographical area are included within the Midwest reportable segment. Consequently, Exelon has five reportable segments consisting of Mid-Atlantic, Midwest, South and West, ComEd and PECO.

Mid-Atlantic represents Generation's operations primarily in Pennsylvania, New Jersey and Maryland; Midwest includes the operations in Illinois, Indiana, Michigan and Minnesota; and the South and West includes operations primarily in Texas, Georgia, Oklahoma, Kansas, Missouri, Idaho and Oregon. Generation's retail gas, proprietary trading, other revenues and mark to market activities have not been allocated to a segment.

Exelon evaluates the performance of Generation's power marketing activities in Mid-Atlantic, Midwest, and South and West based on revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement of operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd and PECO. Purchased power costs include all costs associated with the procurement of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for internally generated energy and fuel costs associated with tolling agreements. Generation's retail gas, proprietary trading, other revenue and mark-to-market activities are not allocated to a segment. Exelon does not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

ComEd and PECO each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. PECO has two operating segments, electric and gas delivery, which are aggregated into one reportable segment primarily due to their similar economic characteristics and the regulatory environments in which they operate. Exelon evaluates the performance of ComEd and PECO based on net income.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements as follows:

	Generation [(a)]	ComEd	PECO	Other	Intersegment Eliminations	Consolidated
Total revenues [(b)]:						
2010	$10,025	$ 6,204	$5,519	$ 755	$(3,859)	$18,644
2009	9,703	5,774	5,311	757	(4,227)	17,318
2008	10,754	6,136	5,567	697	(4,295)	18,859
Intersegment revenues [(c)]:						
2010	$ 3,102	$ 2	$ 5	$ 756	$(3,859)	$ 6
2009	3,472	2	6	756	(4,227)	9
2008	3,586	4	10	695	(4,295)	—
Depreciation and amortization						
2010	$ 474	$ 516	$1,060	$ 25	$ —	$ 2,075
2009	333	494	952	55	—	1,834
2008	274	464	854	42	—	1,634
Operating expenses [(b)]:						
2010	$ 6,979	$ 5,148	$4,858	$ 792	$(3,859)	$13,918
2009	6,408	4,931	4,614	840	(4,225)	12,568
2008	6,760	5,469	4,868	758	(4,295)	13,560
Interest expense, net:						
2010	$ 153	$ 386	$ 193	$ 85	$ —	$ 817
2009	113	319	187	112	—	731
2008	136	348	226	132	(10)	832
Income (loss) from continuing operations before income taxes:						
2010	$ 3,150	$ 694	$ 476	$ (91)	$ (8)	$ 4,221
2009	3,555	603	499	(235)	(3)	4,419
2008	3,388	329	475	(158)	—	4,034
Income taxes:						
2010	$ 1,178	$ 357	$ 152	$ (27)	$ (2)	$ 1,658
2009	1,433	229	146	(102)	6	1,712
2008	1,130	128	150	(91)	—	1,317
Income (loss) from continuing operations:						
2010	$ 1,972	$ 337	$ 324	$ (64)	$ (6)	$ 2,563
2009	2,122	374	353	(133)	(9)	2,707
2008	2,258	201	325	(67)	—	2,717
Income (loss) from discontinued operations:						
2010	$ —	$ —	$ —	$ —	$ —	$ —
2009	—	—	—	—	—	—
2008	20	—	—	—	—	20
Net income (loss):						
2010	$ 1,972	$ 337	$ 324	$ (64)	$ (6)	$ 2,563
2009	2,122	374	353	(133)	(9)	2,707
2008	2,278	201	325	(67)	—	2,737
Capital expenditures:						
2010	$ 1,883	$ 962	$ 545	$ 14	$ (78) [(d)]	$ 3,326
2009	1,977	854	388	54	—	3,273
2008	1,699	953	392	73	—	3,117
Total assets:						
2010	$24,534	$21,652	$8,985	$6,651	$(9,582)	$52,240
2009	22,406	20,697	9,019	6,088	(9,030)	49,180

(a) Generation represents the three segments, Mid-Atlantic, Midwest, and South and West as shown below. Intersegment revenues for the years ended December 31, 2010, 2009 and 2008, represent Mid-Atlantic revenue from sales to PECO of $2,092 million,

$2,016 million and $2,081 million, respectively, and Midwest revenue from sales to ComEd of $1,010 million, $1,456 million and $1,505 million, respectively.

(b) For the years ended December 31, 2010, 2009 and 2008, utility taxes of $205 million, $232 million, and $236 million, respectively, are included in revenues and expenses for ComEd. For the years ended December 31, 2010, 2009 and 2008, utility taxes of $271 million, $249 million and $271 million, respectively, are included in revenues and expenses for PECO.

(c) The intersegment profit associated with Generation's sale of AECs to PECO is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. See Note 2—Regulatory Matters for additional information on AECs. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

(d) Represents capital projects transferred from BSC to Generation, ComEd and PECO. These projects are shown as capital expenditures at Generation, ComEd and PECO and the capital expenditure is eliminated upon consolidation.

	Mid-Atlantic	Midwest	South and West	Other [b]	Generation
Total revenues [a]:					
2010	$3,246	$5,762	$ 692	$325	$10,025
2009	3,195	5,538	714	256	9,703
2008	3,381	5,602	1,298	473	10,754
Revenues net of purchased power and fuel expense:					
2010 [c]	$2,512	$4,081	$ (131)	$100	$ 6,562
2009	2,578	4,148	(117)	162	6,771
2008	2,721	4,100	(73)	434	7,182

(a) Includes all sales to third parties and affiliated sales to ComEd and PECO. For the years ended December 31, 2010, 2009 and 2008, there were no transactions among Generation's reportable segments which would result in intersegment revenue for Generation.

(b) Includes retail gas, proprietary trading, other revenue and mark-to-market activities as well as amounts paid related to the Illinois Settlement Legislation.

(c) In 2010, Other also includes the $57 million lower of cost or market impairment for the ARP SO_2 allowances further described in Note 18—Commitments and Contingencies.

21. Related-Party Transactions

Exelon

The financial statements of Exelon include related-party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2010	2009	2008
Operating revenues from affiliates			
CTFT [(a)]	$—	$—	$ 3
PETT [(b)]	—	3	5
PECO [(c)]	6	9	—
Total operating revenues from affiliates	$ 6	$ 12	$ 8
Fuel purchases from related parties			
Keystone Fuels, LLC	$ 74	$ 56	$ 73
Conemaugh Fuels, LLC	70	69	54
Total fuel purchases from related parties	$144	$125	$127
Charitable contribution to Exelon Foundation [(d)]	$ 10	$ 10	$—
Interest expense to affiliates, net			
CTFT [(a)]	$—	$—	$ 6
ComEd Financing II [(e)]	—	—	2
ComEd Financing III	13	13	13
PETT [(b)]	—	51	101
PECO Trust III	6	6	6
PECO Trust IV	6	6	6
Other	—	1	(1)
Total interest expense to affiliates, net	$ 25	$ 77	$133
Loss in equity method investments			
ComEd Funding [(a)]	$—	$—	$ 8
PETT [(b)]	—	24	16
NuStart Energy Development, LLC	—	3	—
Other	—	—	2
Total loss in equity method investments	$—	$ 27	$ 26

	As of December 31, 2010	As of December 31, 2009
Investments in affiliates		
ComEd Financing III	$ 6	$ 7
PETT (b)	—	5
PECO Energy Capital Corporation	4	4
PECO Trust IV	5	4
Total investments in affiliates	$ 15	$ 20
Payables to affiliates (current)		
ComEd Financing III	$ 4	$ 4
PECO Trust III	1	1
Total payables to affiliates (current)	$ 5	$ 5
Long-term debt to PETT and other financing trusts (including due within one year)		
ComEd Financing III	$206	$206
PETT (b)	—	415
PECO Trust III	81	81
PECO Trust IV	103	103
Total long-term debt due to financing trusts	$390	$805

(a) During 2008, ComEd fully paid its long-term debt obligations to CTFT and received its current receivable from CTFT. ComEd Funding liquidated its investment in CTFT and ComEd liquidated its investment in ComEd Funding. This resulted in the elimination of operating revenues and interest expense applicable to CTFT, and equity in losses of the unconsolidated affiliate, ComEd Funding.

(b) PETT was consolidated in Exelon's and PECO's financial statements on January 1, 2010 pursuant to authoritative guidance relating to the consolidation of VIEs. See Note 1—Significant Accounting Policies for additional information. PETT was liquidated and dissolved upon repayment of the debt in September 2010.

(c) The intersegment profit associated with Generation's sale of AECs to PECO is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. See Note 2—Regulatory Matters for additional information.

(d) Exelon Foundation is a nonconsolidated not-for-profit Illinois corporation. The Exelon Foundation was established in 2007 to serve educational and environmental philanthropic purposes and does not serve a direct business or political purpose of Exelon.

(e) ComEd Financing II was liquidated and dissolved upon repayment of the debt in 2008.

22. Quarterly Data (Unaudited)

The data shown below includes all adjustments which Exelon considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income	
	2010	2009	2010	2009	2010	2009
Quarter ended:						
March 31	$4,461	$4,722	$1,402	$1,255	$749	$712
June 30	4,398	4,141	1,018	1,016	445	657
September 30	5,291	4,339	1,367	1,403	845	757
December 31	4,494	4,116	939	1,076	524	581

	Average Basic Shares Outstanding (in millions)		Net Income per Basic Share	
	2010	2009	2010	2009
Quarter ended:				
March 31	661	659	$1.13	$1.08
June 30	661	659	0.67	1.00
September 30	662	660	1.28	1.15
December 31	662	660	0.79	0.88

	Average Diluted Shares Outstanding (in millions)		Net Income per Diluted Share	
	2010	2009	2010	2009
Quarter ended:				
March 31	662	661	$1.13	$1.08
June 30	662	661	0.67	0.99
September 30	663	662	1.27	1.14
December 31	663	662	0.79	0.88

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

	2010				2009			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$44.49	$43.32	$45.10	$49.88	$51.98	$54.47	$51.46	$58.98
Low price	39.05	37.63	37.24	42.97	45.90	47.30	44.24	38.41
Close	41.64	42.58	37.97	43.81	48.87	49.62	50.12	45.39
Dividends	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525

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