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Exelon Corporation 2008 Financial Information

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CORPORATE PROFILE

Exelon Corporation is one of the nation's largest electric utilities with approximately $19 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 485,000 customers in the Philadelphia area. Exelon is headquartered in Chicago and trades on the NYSE under the ticker EXC.

INVESTOR AND GENERAL INFORMATION

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Stock Ticker
EXC

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Shareholder Inquiries
Exelon Corporation has appointed BNY Mellon 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 shareholder services at BNY Mellon at the toll-free number shown to the left or access their website at www.bnymellon.com/shareowner/isd.

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 140,000 holders of record of its common stock as of December 31, 2008.

The 2008 Form 10-K Annual Report to the Securities and Exchange Commission was filed on February 6, 2009. 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 805398, Chicago, Illinois 60680-5398.

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 BNY Mellon. To use this service, please call our toll-free number, 1.866.530.8108.

FILING FORMAT

The information included within this Financial Information supplement has been taken from Exelon Corporation's (Exelon) Form 10-K annual report for the year ended December 31, 2008. That annual report was filed with the Securities and Exchange Commission (SEC) on February 6, 2009 and can be viewed and retrieved through the Commission's web site at www.sec.gov or our web site 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 2008 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 2008 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 the document from Katherine K. Combs, Vice President and Corporate Secretary, Exelon Corporation, P.O. Box 805398, Chicago, Illinois 60680-5398.

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GENERAL DESCRIPTION OF OUR BUSINESS

General

Exelon, a utility services holding company, operates through its principal subsidiaries—Exelon Generation Company, LLC (Generation), Commonwealth Edison Company (ComEd) and PECO Energy Company (PECO)—as described below, each of which is treated as an operating segment by Exelon. See Note 20 of the 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.

Proposed Acquisition of NRG Energy, Inc.

On October 19, 2008, Exelon offered to acquire all of the common stock of NRG Energy, Inc. (NRG) in an all-stock transaction. NRG is engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, and the trading of energy, capacity and related products in the United States and select international markets. On November 12, 2008, Exelon announced an exchange offer in which Exelon, through its wholly owned subsidiary Exelon Xchange, offered to acquire each of the outstanding shares of NRG common stock in exchange for 0.485 of a share of Exelon common stock plus cash in lieu of fractional shares, representing a total equity value of approximately $6.2 billion for NRG based on Exelon's closing price on October 17, 2008. On January 7, 2009, Exelon announced that at the time of the initial expiration date of the offer, January 6, 2009, NRG shareholders had tendered approximately 106 million shares of common stock of NRG, representing just over 45.6% of all outstanding shares of NRG common stock, and that Exelon had extended the expiration date of the exchange offer until 5:00 PM New York City time on February 25, 2009 unless further extended.

The exchange offer is the first step in Exelon's plan to acquire all of the issued and outstanding shares of NRG common stock. Exelon intends, promptly after completion of the offer, to seek to have NRG consummate a second-step merger of Exelon Xchange or another wholly owned subsidiary of Exelon with and into NRG. Pursuant to the terms of the second-step merger, each remaining issued and outstanding share of NRG common stock (other than shares of NRG common stock owned by Exelon, Exelon Xchange or NRG or held by NRG stockholders who perfect appraisal rights under Delaware law, to the extent available) would be converted into the right to receive the same number of shares of Exelon common stock as exchanged for NRG common stock in the offer.

Exelon has publicly expressed a desire to enter into a negotiated business combination with NRG. Exelon believes that a negotiated business combination could be structured in a way that would have additional benefits to stockholders of NRG and Exelon. As of December 31, 2008, Exelon had incurred approximately $18 million in transaction costs in connection with its proposed acquisition of NRG, which have been expensed as of December 31, 2008.

Exelon must receive approval from and/or make filings with various foreign, Federal and state regulatory agencies with respect to the offer and the second-step merger. At the Federal level, these approvals include the approval of Federal Energy Regulatory Commission (FERC) under the Federal Power Act and the Nuclear Regulatory Commission (NRC) under the Atomic Energy Act. In addition, under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act), the exchange of shares pursuant to the offer cannot be completed until Exelon has made required notifications and given certain information and materials to the Federal Trade Commission (FTC) and/or the Antitrust Division of the United States Department of Justice (DOJ) and until specified waiting period requirements have expired. At the state level, final orders of each of the Pennsylvania Public Utility Commission (PAPUC), the New York Public Service Commission, the California Public Utility Commission (CPUC), and the Public Utility Commission of Texas (PUCT) approving the consummation of the offer and, in some jurisdictions, the second step-merger are required. Other state approvals may be required and State Attorneys General may also investigate the transaction.

On December 17, 2008, Exelon filed notification with the FTC and DOJ of its intention to acquire NRG in compliance with the pre-merger notification requirements of the HSR Act, and on December 18, 2008, filed an application with FERC for approval of the proposed business combination. On January 30, 2009, Exelon filed an application with NRC for approval of the indirect transfer of NRC licenses for the NRG nuclear stations and, if required, Generation's nuclear stations. On February 4, 2009, NRG's legal counsel submitted a letter to the NRC arguing that Exelon's application for NRC approval is insufficient, premature, and speculative and raises significant policy issues. Exelon intends to address the arguments raised by NRG's counsel. Additionally, on December 22, 2008, Exelon filed petitions seeking approval of the acquisition with the New York Public Service Commission and the CPUC, although the CPUC declined to accept the filing for technical reasons. Exelon intends to submit a revised application to the CPUC. On January 5, 2009, Exelon filed an application with the PUCT seeking approval of the proposed NRG acquisition. On January 29, 2009, the PUCT staff referred several questions to the PUCT relating to the sufficiency and timing of the application filed

with the PUCT on January 5, 2009. As part of the FERC filing, Exelon proposed to divest its three facilities in Texas to ensure that the combined company will not own more generating assets in the Texas power market than is allowed under Federal law. The three proposed facilities are Mountain Creek, Handley, and LaPorte, totaling approximately 2,400 MW of generating capacity. The plans also include transferring to a third party Exelon's power purchase agreements in Texas totaling approximately 1,200 MW of generating capacity. In addition, the combined company would divest approximately 1,000 MW of generating capacity in the PJM Interconnection, LLC (PJM) East market, involving plants currently owned by NRG. Exelon does not believe there are any other material generation overlap issues related to the proposed combination.

In connection with the decline in current market conditions and the potential divestiture of the Texas plants proposed in its December 2008 FERC filing, Generation evaluated its Texas plants for potential impairment as of December 31, 2008 pursuant to Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). The impairment evaluation was performed to assess whether the carrying values of the plants were not recoverable. Although energy market conditions have deteriorated since mid-2008, in part reflecting lower commodity prices, which could have an adverse impact on the potential sales price of these plants; Generation's evaluation indicated that the estimated undiscounted future cash flows exceeded the carrying values of the plants and an impairment did not exist as of December 31, 2008 under the held and used model of SFAS No. 144. As Exelon continues its efforts to acquire NRG, Generation will continue to evaluate its Texas plants for impairment, taking into account current energy market conditions, the likelihood and timing of the divestiture of these plants and the potential sales proceeds that might be obtained. Should current market conditions further decline or the likelihood of divestiture increase, an impairment may be triggered and any potential impairment of its Texas plants could have a material adverse impact on Exelon's and Generation's results of operations in the period in which the impairment is recorded.

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 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 distribution and transmission 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 19101, 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 megawatts (MWs). 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 that is operated consistently at high capacity factors position it well to succeed in competitive energy markets.

At December 31, 2008, Generation owned generation assets with an aggregate net capacity of 24,809 MWs, including 16,983 MWs of nuclear capacity. In addition, Generation controlled another 6,483 MWs of capacity through long-term contracts.

Generation's wholesale marketing unit, Power Team, a major wholesale marketer of energy, 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, including a power purchase agreement (PPA) with PECO, which expires on December 31, 2010, and procurement contracts with ComEd. In addition, Power Team markets energy in the wholesale bilateral and spot markets.

Generation's retail business provides retail electric and gas services as an unregulated retail energy supplier in Illinois, Michigan and Ohio. Generation's retail business is dependent upon continued deregulation of retail electric and gas markets and its ability to obtain supplies of electricity and gas at competitive prices in the wholesale market. The low-margin nature of the business makes it important to service customers with higher volumes so as to manage costs.

Generation is a public utility under the Federal Power Act subject to regulation by the FERC. Under the Federal Power Act, FERC also has jurisdiction over third-party financings and certain holding company matters, including review of mergers, 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. Additionally, Generation is subject to mandatory reliability standards by the North American Electric Reliability Corporation (NERC), with the approval of the FERC. The promulgation of these standards has created the risk of fines and penalties being imposed by FERC for noncompliance. Exelon has therefore formed a company-wide NERC Reliability Standards Compliance Program, which includes an employee training program, independent audits, and self assessments.

See Note 3 of the Notes to Consolidated Financial Statements for additional information.

Generating Resources

At December 31, 2008, the generating resources of Generation consisted of the following:

Type of Capacity	MWs
Owned generation assets [(a)]	
Nuclear	16,983
Fossil	6,184
Hydroelectric	1,642
Owned generation assets	24,809
Long-term contracts [(b)]	6,483
Total generating resources	31,292

(a) See "Fuel" for sources of fuels used in electric generation.
(b) Long-term contracts range in duration up to 21 years.

The owned and contracted generating resources of Generation are located in the United States in the Midwest region, which is comprised of Illinois (approximately 47% of capacity), the Mid-Atlantic region, which is comprised of Pennsylvania, New Jersey, Maryland and West Virginia (approximately 36% of capacity), the Southern region, which is comprised of Texas, Georgia and Oklahoma (approximately 16% of capacity), and the New England region, which is comprised of Massachusetts and Maine (approximately 1% of capacity).

Nuclear Facilities

Generation has ownership interests in eleven nuclear generating stations currently in service, consisting of 19 units with 16,983 MWs of capacity. Generation's nuclear fleet plus its ownership interest in two generating units at the Salem Generating Station (Salem) generated 139,342 gigawatt hours (GWhs), or approximately 93% of Generation's total output, for the year ended December 31, 2008. For additional information regarding Generation's electric generating capacity by station, see ITEM 2. Properties of Exelon's 2008 Form 10-K. Generation's nuclear generating stations are 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 Public

Service Enterprise Group Incorporated (PSEG). In 2008 and 2007, electric supply (in GWhs) generated from the nuclear generating facilities was 79% and 74%, respectively, of Generation's total electric supply, which also includes fossil and hydroelectric generation and electric supply purchased for resale.

AmerGen Reorganization. AmerGen Energy Company, LLC (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. Generation, as the new licensee, adopted all open NRC docket items related to these generating stations as a result of the merger. The reorganization will not impact the operations of these generating stations.

Nuclear Operations. Capacity factors, which are significantly affected by the number and duration of 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.

Generation continues to aggressively manage 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 trading activities. Also, 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. During 2008 and 2007, the nuclear generating facilities operated by Generation achieved a 93.9% and 94.5% capacity factor, respectively.

In addition to the rigorous maintenance and equipment upgrades performed by Generation during scheduled refueling outages, which support the safe, reliable operation of its nuclear units, Generation has extensive operating and security procedures in place that ensure the safe operation of the nuclear units. In addition, Generation has extensive safety systems in place that 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 station. 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. 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 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.

NRC reactor oversight results, as of December 31, 2008, show that the performance indicators for the nuclear plants operated by Generation are all in the highest performance band.

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, and Quad Cities Units 1 and 2. The following table summarizes the current operating license expiration dates for Generation's nuclear facilities in service:

Station	Unit	In-Service Date [e]	Current License Expiration
Braidwood [a]	1	1988	2026
	2	1988	2027
Byron [a]	1	1985	2024
	2	1987	2026
Clinton [c]	1	1987	2026
Dresden [a, d]	2	1970	2029
	3	1971	2031
LaSalle [a]	1	1984	2022
	2	1984	2023
Limerick [b]	1	1986	2024
	2	1990	2029
Oyster Creek [c]	1	1969	2009
Peach Bottom [b, d]	2	1974	2033
	3	1974	2034
Quad Cities [a, d]	1	1973	2032
	2	1973	2032
Salem [b]	1	1977	2016
	2	1981	2020
Three Mile Island [c]	1	1974	2014

(a) Stations previously owned by ComEd.
(b) Stations previously owned by PECO.
(c) Stations previously owned by AmerGen.
(d) NRC license renewals have been received for these units.
(e) Denotes year in which nuclear unit began commercial operations.

In December 2004, the NRC issued an order that will permit Oyster Creek to operate beyond its license expiration in April 2009 if the NRC has not completed reviewing the application for renewal. In July 2005, Generation applied for license renewal for Oyster Creek on a timeline consistent and integrated with the other planned license renewal filings for the Generation nuclear fleet. The application was challenged by various citizen groups and the New Jersey Department of Environmental Protection (NJDEP). The contentions raised by these groups were reviewed and rejected by NRC's Atomic Safety Licensing Board (ASLB). In January 2008, the citizens group appealed the rejection of its contention to the NRC Commissioners. If the NRC Commissioners reject the appeal, the citizens group can further appeal to the Federal courts. The NJDEP appealed to the Third Circuit Court of Appeals one of its rejected contentions asserting that the NRC must consider terrorism risks as part of the re-licensing proceeding. This contention had previously been rejected by the ASLB and the NRC Commissioners. Further, in January 2008, AmerGen received a letter from the NJDEP concluding that Oyster Creek's continued operation is consistent with New Jersey's Coastal Management Program, and approving Oyster Creek's coastal land use plans for the next 20 years. This consistency determination is a necessary element for license renewal. With the NJDEP consistency determination and the rejection of the sole remaining contention by the ASLB, Generation is currently awaiting the Commission's decision on appeal and completion of the NRC staff's consideration of the license renewal for Oyster Creek. The NRC's approval is expected in the first quarter of 2009.

On January 8, 2008, AmerGen submitted an application to the NRC to extend the operating license of TMI Unit 1 for an additional 20 years from the expiration of its current license to April 2034. The NRC is expected to spend up to 30 months to review the application before making a decision. To date there have been no legal challenges to the application and the time for filing objections has expired. Generation expects approval of the application to be granted by the NRC.

Generation expects to apply for and obtain approval of license renewals for the remaining facilities. 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.

Generation is a member of NuStart Energy Development, LLC (NuStart), a consortium of ten companies that was formed for the purpose of seeking a license to build a new nuclear facility under the NRC's new permitting process. As of December 31, 2008, Generation's investment in NuStart was $2 million.

New Site Development. Generation pursues growth opportunities that are consistent with its disciplined approach to investing to maximize shareholder value, taking earnings, cash flow and financial risk into account. Generation currently is involved in development activities that would allow for the possible construction of a new nuclear plant in Texas. These development activities preserve for Exelon and Generation the option to develop a new nuclear plant in Texas without immediately committing to the full project. In order to continue preserving and assessing this option, Exelon and Generation have approved expenditures on the project of up to $100 million, which includes fees and costs related to the application process for a combined Construction and Operating License (COL), reservation payments and other costs for long-lead components of the project, and other site evaluation and development costs. Amounts spent on the project through December 31, 2008 have been expensed and total approximately $76 million. The development phase of the project is expected to extend into 2009, with approval of funding beyond the $100 million commitment subject to management review and Exelon board approval. Generation has not made a decision to build a new nuclear plant at this time.

On December 7, 2007, Generation reached an agreement with the City of San Antonio acting by and through the City Public Service Board, a Texas municipal utility known as CPS Energy (CPS), under which CPS agreed to fund a portion of Generation's exploratory costs associated with the possible new nuclear power plant in southeast Texas and related costs for long-lead components. In exchange for its funding commitment, CPS received an option to acquire up to a 40% ownership interest in the new plant and its energy output. If CPS exercises its option, it will be obligated to fund its proportionate share of all project costs and liabilities. The decision whether to build the new nuclear plant will continue to reside solely with Exelon and Generation.

On September 2, 2008, Generation submitted its COL application to the NRC seeking authorization to build and operate a new dual unit nuclear generating facility in Victoria County in southeast Texas. Allowing the NRC 35 months to perform a technical review and 12 months for public hearings, the COL could be issued in 2012. In addition, Generation filed Part I and Part II of a loan guarantee application with the U.S. Department of Energy (DOE) for these potential new units on September 26, 2008 and December 18, 2008, respectively. In November 2008, Generation announced that it was considering alternative technologies to the Economic Simplified Boiling Water Reactor (ESBWR) technology initially selected for the project. Generation has since determined to select a technology other than the ESBWR technology and continues to evaluate alternative technologies. Generation expects to file an amendment to its Part II loan guarantee application in March 2009 to address technology choice.

Among the various conditions that must be resolved before any formal decision to build is made by Generation are the successful granting of the COL by the NRC; significant progress to resolve questions around the short-term interim and long-term permanent storage, as well as potential future recycling, of spent nuclear fuel (SNF); broad public acceptance of a new nuclear plant; and assurances that a new plant can be financially successful, which would entail economic analysis that would incorporate assessing construction and financing costs, including the availability of sufficient financing, production and other potential tax credits, and other key economic factors. However, the decision to build the new nuclear plant depends, in large part, upon financial support under the DOE loan guarantee program. At this time, there is considerable uncertainty about the likelihood of DOE financial support for the project due to the limited appropriations available to DOE for this purpose and the number of projects competing for those limited resources.

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 is developing dry cask storage facilities, as necessary, to support operations.

As of December 31, 2008, Generation had approximately 50,600 SNF assemblies (12,200 tons) stored on site in SNF pools or dry cask storage. 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 license renewal period, and through decommissioning, until the DOE completes removing SNF from the sites. The following table describes the current status of Generation's SNF storage facilities.

Site	Date for loss of full core reserve [a]
Braidwood	2013
Byron	2011
Clinton	2018
Dresden	Dry cask storage in operation
LaSalle	2010
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	2011
Three Mile Island	Life of plant storage capable in SNF pool

(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.

For a discussion of matters associated with Generation's contracts with the DOE for the disposal of SNF, see Note 13 of the Notes to Consolidated Financial Statements.

As a by-product of their operations, nuclear generating units produce low-level radioactive waste (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 currently expected to be operational until after 2011. 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 has on-site storage capacity at its nuclear generation stations for limited amounts of LLRW and has been shipping its LLRW to disposal facilities in South Carolina, which at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey and Connecticut which include Oyster Creek and Salem, and Utah. With a limited number of available LLRW disposal facilities, Generation continues to anticipate difficulties in shipping of LLRW off of its sites and continues to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize cost impacts.

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 protection provisions. See "Nuclear Insurance" within Note 18 of the Notes to Consolidated Financial Statements for details.

For information regarding property insurance, see ITEM 2. Properties—Generation of Exelon's 2008 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. For a discussion of matters regarding the adequacy of Generation's nuclear decommissioning trust funds to meet its decommissioning obligations, the obligations imposed on Generation related to the potential excess or shortfall of trust funds, the impact on Generation's accounting for its former ComEd units as a result of a shortfall of trust funds and other matters related to Generation's trust funds and decommissioning obligations, see Management's Discussion and Analysis of Financial Condition and Results of Operations, Executive Overview, Capital and Credit Market Crisis; 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 8 and 12 of the Notes to Consolidated Financial Statements.

Dresden Unit 1, Peach Bottom Unit 1 and Zion (Zion Station), a two-unit nuclear generation station, have ceased power generation. SNF at Dresden Unit 1 is currently being stored in dry cask storage until a permanent repository under the Nuclear Waste Policy Act

of 1982 (NWPA) is completed. All of Peach Bottom Unit 1's SNF has been moved off site. SNF at Zion Station is currently stored in on-site storage pools. Generation's liability to decommission Dresden Unit 1, Peach Bottom Unit 1 and Zion Station was $759 million at December 31, 2008. As of December 31, 2008, nuclear decommissioning trust funds set aside to pay for these obligations were $995 million.

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

If the various closing conditions under the Asset Sale Agreement are satisfied and the transaction is completed, Generation will transfer to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in nuclear decommissioning trusts (approximately $749 million as of December 31, 2008). In consideration for Generation's transfer of those assets, ZionSolutions will assume decommissioning and other liabilities associated with Zion Station. For accounting purposes, based on agreements signed to date, the decommissioning funds are expected to continue to be recorded on Generation's balance sheet and the transferred decommissioning obligation is expected to be replaced with a payable to ZionSolutions on Generation's balance sheet. ZionSolutions will take possession and control of the land associated with Zion Station pursuant to a Lease Agreement with Generation, to be executed at the closing. Under the Lease Agreement, ZionSolutions will commit to complete the required decommissioning work according to an established schedule and will construct a dry cask storage facility on the land for the spent nuclear fuel currently held in spent fuel pools at Zion Station. Rent payable under the Lease Agreement will be $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 spent nuclear fuel storage facility. To reduce any potential risk of default by EnergySolutions or ZionSolutions, EnergySolutions is required to provide a $200 million letter of credit to be used to fund decommissioning costs in case of a shortfall of decommissioning funds following specified failures of performance. EnergySolutions has also provided a performance guarantee and will enter into other agreements that will provide rights and remedies for Generation 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 low level waste volume of Zion Station. However, if the resources of EnergySolutions Inc. and its subsidiaries are inadequate to complete required decommissioning work, Generation may be required to complete the work at its own expense.

ZionSolutions and Generation will also enter into a Put Option Agreement pursuant to which ZionSolutions will have the option to transfer the remaining Zion Station assets and any associated liabilities back to Generation upon completion of all required decommissioning and other work at Zion Station. The purchase price payable under the Put Option Agreement is $1.00 plus the assumption of associated liabilities.

Completion of the transactions contemplated by the Asset Sale Agreement is subject to the satisfaction of a number of closing conditions, including approval of the license transfer from the NRC, which is expected in early 2009. On July 14, 2008, the IRS issued a private letter ruling indicating that the proposed transfer of the decommissioning funds would be treated as non-taxable to both Generation and EnergySolutions. Prior to completion of the transaction, EnergySolutions must submit a budget that demonstrates that the required work can be completed on schedule for the amount of funds held in decommissioning trusts. On October 14, 2008, EnergySolutions announced that it intended to defer the transfer of the Zion Station assets until after the financial markets stabilize and EnergySolutions reaffirms that there is sufficient value in the Zion decommissioning trust funds to ensure the success of the Zion early decommissioning project. To date, this continues to be EnergySolution's intention. Pursuant to their agreement, EnergySolutions and Generation have until December 31, 2009, to close the transaction. Generation believes that accelerated decommissioning will make the land available for other uses earlier than originally thought possible, and can be completed cost effectively for the amounts that were collected from ratepayers and deposited into the nuclear decommissioning trust funds for Zion Station.

Fossil and Hydroelectric Facilities

Generation operates various fossil and hydroelectric facilities and maintains ownership interests in several other facilities including LaPorte, Keystone, Conemaugh and Wyman, which are operated by third parties. In 2008 and 2007, electric supply (in GWhs) generated from owned fossil and hydroelectric generating facilities was 6% and 6%, respectively, 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 2008 Form 10-K.

Licenses. Fossil generation plants are generally not licensed and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. Hydroelectric plants are licensed by FERC. The Muddy Run and Conowingo facilities have licenses that expire in

August 2014. Generation is in the process of performing pre-application analyses and anticipates filing a Notice of Intent to renew the licenses in 2009 pursuant to FERC regulations. For those plants located within the control areas administered by PJM or the New England control area administered by ISO New England Inc. (ISO-NE), notice is required to be provided to PJM or ISO-NE, as applicable, before a plant can be retired.

Potential New Build. On May 1, 2008, Generation announced that it is actively pursuing the development of a 600-megawatt combined-cycle natural gas power plant in Pennsylvania. The new plant would advance Exelon's efforts to combat carbon emissions associated with electricity generation. Generation has been looking at several existing plant sites that it owns with access to the transmission lines, water and fuel needed to operate a new power plant. Generation has stated that a final decision on whether to move forward would be made only after it had more certainty around environmental permitting and had performed a more detailed economic review. Generation will continue to study the development of the project but will not make material investments or pursue permits until general market conditions have improved the estimated economic returns of the project. Amounts spent on the project to date, which are not material, have been expensed.

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 2008 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, 2008:

Seller	Location	Expiration	Capacity (MWs)
Kincaid Generation, LLC	Kincaid, Illinois	2013	1,108
Tenaska Georgia Partners, LP [(a)]	Franklin, Georgia	2030	942
Tenaska Frontier, Ltd	Shiro, Texas	2020	830
Green Country Energy, LLC	Jenks, Oklahoma	2022	795
Elwood Energy, LLC	Elwood, Illinois	2012	775
Lincoln Generating Facility, LLC	Manhattan, Illinois	2011	664
Wolf Hollow	Granbury, Texas	2023	350
Dynegy Power Marketing, Inc.	East Dundee, Illinois	2009	330
Old Trail Windfarm, LLC	McLean, Illinois	2026	198
Others [(b)]	Various	2011 to 2023	491
Total			6,483

(a) Commencing June 1, 2010 and lasting for 20 years, Generation has agreed to sell its rights to 942 MWs of capacity, energy, and ancillary services supplied from its existing long-term contract with Tenaska Georgia Partners, LP through a tolling agreement with Georgia Power, a subsidiary of Southern Company.

(b) Includes long-term capacity contracts with eleven counterparties.

Federal Power Act

The Federal Power Act gives FERC exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to FERC's jurisdiction are required to file rate schedules with FERC with respect to wholesale sales and transmission of electricity. Open-Access Transmission tariffs established under FERC regulation give Generation transmission access that enables Generation to participate in competitive wholesale markets.

Market-Based Rate Matters

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 sales of electricity. 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. See Note 3 of the Notes to Consolidated Financial Statements for additional information regarding various regulatory filings concerning these matters.

For a number of years, regional transmission organizations (RTOs), such as PJM, have been formed in a number of regions to provide transmission service across multiple transmission systems. The intended benefits of establishing these entities include 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.

To date, PJM, the Midwest Independent Transmission System Operator, Inc. (MISO), ISO-NE and Southwest Power Pool, have been approved as RTOs. Because of some states' opposition to imposition of centralized energy and capacity markets, FERC is seeking to obtain some of the benefits of RTOs by means of making more effective rules governing open-access transmission in regions that do not have RTOs or independent system operators.

PJM Reliability Pricing Model (RPM)

On August 31, 2005, PJM submitted a proposal to FERC for a new capacity payment construct to replace PJM's then-existing capacity obligation rules. The proposal provided for a forward capacity procurement auction to establish capacity and payment obligations using a demand curve and locational deliverability zones for capacity. FERC approved PJM's use of RPM in December 2006. For additional information regarding certain legal challenges to RPM, see Note 3 of the Notes to Consolidated Financial Statements.

Marginal-Loss Dispatch and Settlement

On June 1, 2007, PJM implemented marginal-loss dispatch and settlement for its competitive wholesale electric market. Marginal-loss dispatch recognizes the varying delivery costs of transmitting electricity from individual generator locations to the places where customers consume the energy. Prior to the implementation of marginal-loss dispatch, PJM had used average losses in dispatch and in the calculation of locational marginal prices. Locational marginal prices in PJM now include the real-time impact of transmission losses from individual sources to loads. PJM believes that the marginal-loss approach is more efficient because the cost of energy that is lost in transmission lines is reduced compared with the former average loss method. As a whole, Generation has experienced an increase in the cost of delivering energy from the generating plant locations to customer load zones due to the implementation of marginal-loss dispatch and settlement.

Illinois Settlement Agreement

In July 2007, following extensive discussions with legislative leaders in Illinois, Generation, ComEd and other generators and utilities in Illinois reached an agreement (Illinois Settlement) with various representatives from the State of Illinois concluding discussions of measures to address concerns about higher electric bills in Illinois without rate freeze, generation tax or other legislation that Exelon believes would have been harmful to consumers of electricity, electric utilities, generators of electricity and the State of Illinois. Legislation reflecting the Settlement (Settlement Legislation) was passed by the Illinois Legislature on July 26, 2007 and was signed into law on August 28, 2007 by the Governor of Illinois. Generation and ComEd committed to contributing $811 million to rate relief programs over four years. Generation committed an aggregate of $747 million, with $435 million available to pay ComEd for rate relief programs for ComEd customers, $307.5 million available for rate relief programs for customers of other Illinois utilities, and $4.5 million available for partially funding operations of the Illinois Power Agency (IPA). Through December 31, 2008, Generation has recognized net costs from its contributions of $629 million in the Statement of Operations of its total commitment of $747 million. See Note 3 of the Notes to Consolidated Financial Statements for additional information regarding the Illinois Settlement Legislation.

Pennsylvania Transition-Related Legislative and Regulatory Matters

See PECO, Retail Electric Services, Pennsylvania Transition-Related Legislative and Regulatory Matters for a discussion of Pennsylvania-related matters that could impact Generation in the future. Generation's PPA with PECO ends on December 31, 2010, after which PECO will procure its energy through alternative means. Pennsylvania has approved the use of competitive, market-

based procurement mechanisms for electricity distribution companies, and Generation could have the opportunity to enter into contracts with PECO and other electricity distribution companies that reflect market prices. In addition, with respect to post-transition electric generation rate increase mitigation concerns, measures suggested by Pennsylvania officials have included rate-cap extensions, rate-increase deferrals and phase-ins, a generation tax and contributions of value (potentially billions of dollars statewide) by Pennsylvania utility companies toward rate-relief programs. Depending on the legislation ultimately passed, Generation's results of operations, financial position and cash flows could be adversely affected. Generation cannot predict the ultimate outcome of these matters.

Fuel

The following table shows sources of electric supply in GWhs for 2008 and estimated for 2009:

	Source of Electric Supply [(a)]	
	2008	2009 (Est.)
Nuclear units	139,342	138,897
Purchases—non-trading portfolio	26,263	31,215
Fossil and hydroelectric units	10,569	11,223
Total supply	176,174	181,335

(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 obligations for sales to other utilities, 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 2010. Generation's contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2011. All of Generation's enrichment requirements have been contracted through 2010. Contracts for fuel fabrication have been obtained through 2012. 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.

Approximately 13% of Generation's uranium enrichment services forward commitments are with European suppliers. In January 2002, the U.S. International Trade Commission determined that USEC, Inc. was "materially injured or threatened with material injury" by low-enriched uranium exported by European suppliers and as a result, the U.S. Department of Commerce assessed countervailing and anti-dumping duties against the European suppliers. Both USEC, Inc. and the European suppliers appealed these decisions. On January 27, 2009, the U.S. Supreme Court issued a ruling regarding the ongoing trade action that permitted the U.S. Department of Commerce to impose anti-dumping duties on low enriched uranium from Europe. As a result of these actions, Generation may incur higher costs for uranium enrichment services necessary for the production of nuclear fuel.

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

Natural gas is procured for gas-fired plants 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 Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates and Note 9 of the Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Team

Generation's wholesale 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 with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to customers. Power Team 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 has also purchased 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.

Power Team also manages the price and supply risks for energy and fuel associated with generation assets and the risks of power marketing activities. Generation has hedges in place that significantly mitigate this risk for 2009 and 2010 and, with the ComEd swap arrangement, also for 2010 into 2013. However, except for the ComEd swap arrangement described below, Generation is exposed to relatively greater commodity price risk beyond 2010 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 well. Generation has estimated greater than 95% and 90% for economic and cash flow hedge ratios for 2009 and 2010, respectively, which includes cash flow and other derivatives, for its energy marketing portfolio. This financial hedge ratio is Generation's estimate of the gross margin that is hedged given the current assessment of market volatility. A portion of Generation's hedge may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. The hedge ratio is not fixed and will vary from time to time depending upon market conditions, demand, energy market option volatility and actual loads. 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 Risk Management Committee (RMC) monitor the financial risks of the power marketing activities. Power Team also uses financial and commodity contracts for proprietary trading purposes but this activity accounts for only a small portion of Power Team's efforts.

At December 31, 2008, 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]
2009	$ 336	$190	$2,212	$ 9
2010	322	25	550	9
2011	331	30	163	9
2012	332	—	64	9
2013	211	—	31	6
Thereafter	1,791	—	—	—
Total	$3,323	$245	$3,020	$ 42

(a) Net capacity purchases include tolling agreements 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, 2008. Expected payments include certain capacity charges which are conditional on plant availability.

(b) Excludes renewable 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.

Beginning in January 2007, ComEd began procuring all of its energy requirements for retail customers from market sources pursuant to the Illinois Commerce Commission (ICC)-approved procurement auction in 2006 or from the PJM administered spot market. In May 2008, approximately one-third of the load in the auction contracts that resulted from the 2006 auction expired, another one-third of the load will expire in May 2009 with the auction contracts for the final third of the load expiring in May 2010. Approximately 35% of the contracted supply from the 2006 auction was awarded to Generation. Suppliers, including Generation, were limited to winning no more than 35% of the load in either the fixed price section or the hourly price section of the auction.

The Illinois Settlement Legislation established a new competitive process for energy procurement to be managed by the IPA, with oversight by the ICC. The IPA's new procurement plan for ComEd's procurement of energy beginning in June 2009 was approved by the ICC in January 2009, as discussed below. At present, ComEd is procuring power under an ICC-approved plan for the period from June 2008 to May 2009. Under this plan, standard block energy purchases, acquired through an ICC-approved Request for Proposal (RFP), coupled with purchases of energy, capacity and ancillary services in PJM-administered markets, are used to replace the portion of the auction contracts that expired on May 31, 2008. Generation was awarded a portion of the standard block energy purchase contracts under this plan. In addition, in order to fulfill a requirement of the Illinois Settlement to mitigate the price risk inherent in this plan, ComEd locked in a portion of the energy price through a five-year financial hedge (a financial swap contract) with Generation. See Notes 3 and 9 of the Notes to Consolidated Financial Statements and ComEd's Procurement Related Proceedings as described below for additional information regarding ComEd's procurement-related proceeding and the financial swap contract.

Generation has a PPA with PECO under which Generation has agreed to supply PECO with all of PECO's electric supply needs through 2010. Generation supplies electricity to PECO from its portfolio of generation assets, PPAs and other market sources. Subsequent to 2010, PECO expects to procure all of its electricity from market sources, which could include Generation. See PECO—Retail Electric Services, Pennsylvania Transition-Related and Regulatory Matters for additional information regarding a PECO regulatory filing in which it proposes to use a 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 2009 are as follows:

(in millions)	
Production plant	$1,060
Nuclear fuel [(a)]	897
Total	$1,957

(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 and 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 also subject to mandatory reliability standards by the NERC, for which Exelon has formed a company-wide NERC Reliability Standards Compliance Program.

ComEd's retail service territory has an area of approximately 11,300 square miles and an estimated population of 8 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 2009 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 MWs; its highest peak load during a winter season occurred on January 15, 2009 and was 16,328 MWs.

Retail Electric Services

Electric utility restructuring legislation was adopted in Illinois in December 1997 to permit competition by competitive electric generation suppliers for the supply of retail electricity. Transmission and distribution service was not impacted by the legislation and continues to remain regulated. The restructuring legislation and related regulatory orders allowed customers to choose a competitive electric generation supplier; required rate reductions and imposed freezes or caps on rates during a transition period following the adoption of the legislation; and allowed the collection of competitive transition charges (CTCs) from customers to permit Illinois utilities to recover a portion of the costs that might not otherwise be recovered in a competitive market (stranded costs) during the transition period. ComEd's transition and rate freeze period ended in January 2007.

As of December 31, 2008, several competitive electric generation suppliers have been granted approval by the ICC to serve retail electricity customers in Illinois. There are currently a minimal number of residential customers being served by alternate suppliers. At December 31, 2008, approximately 43,100 retail customers, representing approximately 51% of ComEd's annual retail kWh sales, had elected to purchase their electricity from a competitive electric generation supplier. Customers who receive electricity from a competitive electric generation supplier continue to pay a delivery charge to ComEd.

Under Illinois law, ComEd is required to deliver electricity to all customers. ComEd's obligation to provide full service electric service including generation service, which is referred to as provider of last resort (POLR) obligations, varies by customer size. ComEd's obligation to provide such service to residential customers and other small customers with demands of under 100 kilowatts (kWs) 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 full service obligation to many of its largest customers with demands of 3 MWs or greater, as this group of customers has previously been declared competitive. ComEd has full service obligations for customers with demands of 100-400kWs, and 400 kWs and above, through May 2010.

Delivery Service Rate Cases. In August 2005, ComEd filed a rate case with the ICC to comprehensively review its tariff and to adjust ComEd's rates for delivering electricity effective January 2007. During 2006, the ICC issued various orders associated with this case, which resulted in a total annual rate increase of $83 million effective January 2007. ComEd and various other parties have appealed the rate order to the courts, but the appeals are not yet resolved.

In October 2007, ComEd filed a rate case with the ICC for approval to increase its delivery service revenue requirement by approximately $360 million to reflect increasing operating costs and its continued investment in delivery service assets since rates were last determined. On September 10, 2008, the ICC issued an order in the rate case approving a $274 million increase in the annual revenue requirement, which became effective on September 16, 2008. ComEd and several other parties have filed appeals of the rate order with the courts. The appeals are not expected to be decided prior to the second quarter of 2009.

ComEd cannot predict the results of the appeals for either of the Delivery Service Rate Cases.

Procurement Related Proceedings. In January 2007, ComEd began procuring electricity under supplier forward contracts with various suppliers, including Generation. The supplier forward contracts resulted from an ICC-approved "reverse-auction" competitive bidding process, which permitted ComEd to recover its electricity procurement costs from retail customers, without markup. The energy price that resulted from the first auction was fixed for each of its staggered terms with the first term extending through May 31, 2008, at which time auction contracts for one-third of ComEd's load requirement expired. Under the Illinois Settlement Legislation, the IPA, under the oversight of the ICC, participates in the design of an electricity supply portfolio for ComEd and will administer a competitive process under which ComEd will procure its electricity supply resources for deliveries in the supply period beginning June 2009. Prior to the IPA's initial participation in ComEd's procurement design portfolio, on December 19, 2007, the ICC approved a plan under which ComEd is procuring power for the period from June 2008 to May 2009. ComEd's purchases acquired through the RFP represent approximately 14% of its expected energy needs from June 2008 through May 2009. Approximately 19% of ComEd's expected energy load, which is purchased on the spot market, for the same period, has been hedged with its variable to fixed financial swap with Generation. The ICC-approved prices reflected in the compliance tariff filing following the ICC's approval of the recent RFP incorporate the applicable PJM RPM capacity prices. As this RFP related to only a portion of ComEd's load requirement beginning in June 2008, the RPM impacts to overall customer electric rates are not significant. However, as ComEd's auction contracts expire and a larger portion of power and energy is procured in the future through a RFP procurement process, increases in capacity prices associated with RPM capacity auctions are expected to have a more significant impact on customer electric rates.

On January 7, 2009, the ICC-approved the IPA plan for ComEd's power procurement from June 2009 through May 2010, which includes the remaining supplier forward contracts, standard block energy purchases to be set through an RFP in 2009, spot market purchases hedged with the financial swap with Generation, and any additional spot market purchases needed to service customers.

See Note 3 of the Notes to Consolidated Financial Statements for additional information regarding the regulatory matters.

Other. Illinois law provides that an electric utility, such as ComEd, will be liable for actual damages suffered by customers in the event of a continuous electricity outage of four hours or more affecting 30,000 or more customers and provides for reimbursement of governmental emergency and contingency expenses incurred in connection with any such outage. Recovery of consequential damages is barred and the affected utility may seek relief from these provisions from the ICC when the utility can show that the cause of the outage was unpreventable due to weather events or conditions, customer tampering or third-party causes. During the years 2008, 2007 and 2006, ComEd does not believe that it had any outages that triggered the 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 regional transmission expansion plan (RTEP) ComEd has various construction commitments, as discussed in Note 18 of the Notes to Consolidated Financial Statements. ComEd's most recently approved budget of capital expenditures for electric plant additions and improvements for 2009 is $1 billion. However, ComEd is currently in the process of reviewing its estimated 2009 capital expenditures, due to recent economic conditions and projected load growth, which may reduce the total capital expenditures.

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 Pennsylvania Public Utility Commission (PAPUC) as to electric and gas 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. Specific operations of PECO are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, PECO is also subject to mandatory reliability standards by the NERC, for which Exelon has formed a company-wide NERC Reliability Standards Compliance Program.

PECO's combined electric and natural gas retail service territory has an area of approximately 2,100 square miles and an estimated population of 3.9 million. PECO provides electric delivery service in an area of approximately 1,900 square miles, with a population of approximately 3.7 million, including 1.4 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 485,000 customers.

PECO has the necessary authorizations to furnish 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 load of electricity 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 MWs; its highest peak load during a winter season occurred on December 20, 2004 and was 6,838 MWs.

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

Retail Electric Services

Electric utility restructuring legislation was adopted in Pennsylvania in December 1996. Pennsylvania permits competition by competitive electric generation suppliers for the supply of retail electricity while transmission and distribution service remains regulated. The legislation and related regulatory orders allow customers to choose a competitive electric generation supplier;

required rate reductions and imposed freezes or caps on rates during a transition period following the adoption of the legislation; and authorized the collection of CTCs from customers to recover a portion of the costs that might not otherwise be recovered in a competitive market (stranded costs) during the transition period. The PECO transition period ends on December 31, 2010.

Under the Pennsylvania Electricity Generation Customer Choice and Competition Act (Competition Act), all of PECO's retail electric customers have the right to choose their generation suppliers. At December 31, 2008, less than 1% of each of PECO's residential and large commercial and industrial loads and 7% of its small commercial and industrial load were purchasing generation service from competitive electric generation suppliers. Customers who purchase electricity from a competitive electric generation supplier continue to pay a delivery charge and CTC to PECO. In addition to retail competition for generation services, PECO's 1998 settlement of its restructuring case (1998 restructuring settlement) mandated by the Competition Act established caps on generation, transmission and distribution rates. The 1998 restructuring settlement also authorized PECO to recover $5.3 billion of stranded costs and to securitize up to $5 billion of its stranded cost recovery.

Under the 1998 restructuring settlement, PECO's electric distribution and transmission rates were capped through June 30, 2005 at the level in effect on December 31, 1996. Electric generation rates, consisting of the charge for stranded cost recovery and a shopping credit or capacity and energy charge, are capped through December 31, 2010. In 2007, the electric generation rate cap increased to $0.0801 per kWh, where it will remain through 2010. The rate caps are subject to limited exceptions, including significant increases in Federal or state taxes or other significant changes in law or regulations that would not allow PECO to earn a fair rate of return. PECO's electric transmission and distribution rates continue in effect until PECO files a rate case or there is some other specific regulatory action to adjust the rates. There are no current proceedings to do so.

As a mechanism for utilities to recover allowed stranded costs, the Competition Act provides for the imposition and collection of non-bypassable CTCs on customers' bills. CTCs are assessed to and collected from all retail customers who have been assigned stranded cost responsibility and access the utility's transmission and distribution systems. As the transition charges are based on access to the utility's transmission and distribution system, they are assessed regardless of whether the customer purchases electricity from the utility or a competitive electric generation supplier. The Competition Act provides, however, that the utility's right to collect CTCs is contingent on the continued operation, at reasonable availability levels, of the assets for which the stranded costs were awarded, except where continued operation is no longer cost efficient because of the transition to a competitive market.

As mentioned above, PECO has been authorized by the PAPUC to recover stranded costs of $5.3 billion over a twelve-year period ending December 31, 2010, with a return on the unamortized balance of 10.75%. At December 31, 2008, the unamortized balance of PECO's stranded costs, or CTC regulatory asset, was approximately $1.7 billion. The following table shows PECO's allowed recovery of stranded costs, and amortization of the associated regulatory asset, for the years 2009 and 2010 as authorized by the PAPUC based on the level of transition charges established in the settlement of PECO's restructuring case and the projected annual retail sales in PECO's service territory. Recovery of CTCs for stranded costs and PECO's allowed return on its recovery of stranded costs are included in revenues. To the extent the actual recoveries of CTCs in any one year differ from the authorized amount set forth below, an annual reconciliation adjustment to the CTC rates is made to increase or decrease the subsequent year's collections accordingly, except during 2010, in which the reconciling adjustments are made quarterly or monthly as needed.

Year (in millions)	Estimated CTC Revenue	Estimated Stranded Cost Amortization
2009	$924	$783
2010	932	883

PECO has a PPA with Generation under which PECO obtains all of its electric supply from Generation through 2010. The price for this electricity is essentially equal to the energy revenues PECO is authorized to recover from customers as specified by PECO's 1998 restructuring settlement mandated by the Competition Act. Subsequent to 2010, PECO expects to procure all of its supply from market sources, which could include Generation.

Pennsylvania Transition-Related Legislative and Regulatory Matters. Over the past two years, elected officials in Pennsylvania have worked on developing legislation to address the Governor's comprehensive energy plan and concerns of anticipated increases in electric generation rates following the expiration of retail electric generation rate cap transition periods. On July 9, 2008, the Pennsylvania Legislature passed and the Governor signed legislation providing a $650 million fund to support investment in renewable power resources and conservation. The fund will be appropriated from Pennsylvania's General Fund. In October 2008, the Pennsylvania General Assembly passed and the Governor signed Act 129 of 2008 (Act 129) into law. This legislation requires that Pennsylvania electric utility companies meet energy-conservation and demand-reduction targets, beginning in 2011, to enhance

the Commonwealth's energy independence and enable programs to help consumers manage their energy use. PECO will be required to transition its electric customers to smart-meter technology over a fifteen-year period and to make available time-of-use rates and real-time price plans. The legislation allows recovery of costs for each of these programs, subject to approval by the PAPUC. If PECO were to fail to achieve the required reductions in consumption within stated deadlines, PECO would be subject to civil penalties of up to $20 million. Any penalties paid would not be recoverable from ratepayers. Finally, Act 129 provides guidelines associated with electricity procurement that support competitive, market-based procurement through auctions, requests for proposal or bilateral agreements with a prudent mix of spot market purchases, short-term contracts and long-term (more than four years) purchase contracts. See Note 3 of the Notes to Consolidated Financial Statements for additional information.

As a result of Act 129, on November 14, 2008, PECO filed an amended comprehensive Default Service Program and Rate Mitigation Plan with the PAPUC seeking approval to provide default electric service following the expiration of electric generation rate caps on December 31, 2010, which was originally filed on September 10, 2008. The PAPUC will conduct a formal proceeding to give all interested parties the opportunity to examine aspects of the amended filing and make independent recommendations. The process is expected to be completed by July 2009. See Note 3 of the 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. During 2008, PECO filed a petition before the PAPUC for a $98 million increase to its distribution revenue to fund critical infrastructure improvement projects that will ensure the safety and reliability of the natural gas delivery system. On October 23, 2008, the PAPUC approved a settlement of a distribution rate increase that provides for an annual revenue increase of $77 million. The approved distribution rate adjustment became effective on January 1, 2009.

PECO's natural gas customers have the right to choose their natural gas suppliers or to purchase their gas supply from PECO at cost. Approximately 30% of PECO's current total yearly throughput is 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 transportation service provided to customers by PECO remains subject to rate regulation. PECO also provides billing, metering, installation, maintenance and emergency response services.

PECO's natural gas supply is provided by purchases from a number of suppliers for terms of up to two years. These purchases are primarily delivered under long-term firm transportation contracts. PECO's aggregate annual firm supply under these firm transportation contracts is 43 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 34% of PECO's 2008-2009 heating season planned supplies.

Construction Budget

PECO'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 RTEP, PECO has various construction commitments, as discussed in Note 18 of the Notes to Consolidated Financial Statements. PECO's most recent estimate of capital expenditures for plant additions and improvements for 2009 is $416 million. However, PECO is currently in the process of reviewing its estimated 2009 capital expenditures, due to recent economic conditions and projected load growth, which may reduce the total capital expenditures.

ComEd and PECO

Transmission Services

ComEd and PECO provide unbundled retail 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. Under FERC's Order Nos. 889 and 2004, 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 or the employees of any energy affiliate of the transmission owner.

PJM is the independent system operator 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.

In March 2007, ComEd filed a request with the FERC seeking approval to update its transmission rates and change the manner in which such rates are determined from fixed rates to a formula rate. In June 2007, FERC issued an order that conditionally approved ComEd's proposal to implement a formula-based transmission rate effective as of May 1, 2007. In October 2007, ComEd made a filing with FERC seeking approval of a settlement agreement reached by most active parties and opposed by no party in the transmission rate proceeding. On January 16, 2008, FERC approved the settlement agreement. On May 15, 2008, ComEd filed its first annual formula update filing with FERC, which updates ComEd's transmission formula rate to include actual 2007 expenses and capital additions plus forecasted 2008 capital additions. The update resulted in a revenue requirement of $430 million, plus an additional $26 million related to the 2007 true-up of actual costs for a total increase of approximately $66 million, which became effective for the period June 1, 2008 through May 31, 2009. In November 2008, FERC accepted the calculation of the new rates with no material changes. As of December 31, 2008, ComEd had a regulatory asset associated with the remaining balance of its 2007 true-up and the estimated effect of the 2008 true-up to be filed in May 2009.

Environmental Regulation

General

Exelon, Generation, ComEd and PECO are subject to regulation regarding environmental matters by the United States and by various states and local jurisdictions where the Registrants operate their facilities. The United States Environmental Protection Agency (EPA) administers certain Federal statutes relating to such matters, as do various interstate and local agencies. Various state environmental protection agencies or boards have jurisdiction over certain activities in states in which Exelon and its subsidiaries do business. State regulation includes the authority to regulate air, water and noise emissions and solid waste disposals.

Authority to address environmental matters is the responsibility of the Board of Directors. The Board of Directors has delegated to its Corporate Governance Committee authority to oversee Exelon's policies and practices 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. In addition, Exelon has a management team to address these matters, including the CEO who also serves as Exelon's Chief Environmental Officer; Executive Vice President of Government and Environmental Affairs and Public Policy; Vice President, Environment, Health and Safety; and Director, Climate Strategy and Programs, 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. For further information on Environmental Regulation in addition to Global Climate Change, see Part I Item 1 Business of Exelon's 2008 Form 10-K.

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 greenhouse gases (GHGs) that many in the scientific community believe contribute to global climate change. Exelon, as a producer of electricity from predominantly low-carbon generating facilities (such as nuclear, hydroelectric and landfill gas), 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 (CO_2) emitted per unit of electricity generated, is among the lowest in the industry. Exelon does produce GHG emissions from the direct combustion of fossil fuels, primarily at its 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; this is also a highly variable component of its GHG emissions to forecast due to the primarily intermediate and peaking profile of Exelon's fossil generating fleet. 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.

Physical Risks. Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena, could affect some, or all, of Exelon's operations. Exelon is currently evaluating potential physical risk issues to its operations resulting from climate change, as well as potential options to manage those risks.

In general, weather patterns and the related impact on electricity and gas usage affect Exelon's results of operations. Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below moderate levels in the winter tend to increase winter heating electricity and gas demand and revenues. As a corollary, moderate temperatures in the winter adversely affect the usage of energy and resulting revenues. Extreme weather conditions may stress ComEd's and PECO's transmission and distribution systems, resulting in increased maintenance and capital expenditures and challenging their ability to meet peak customer demand, thereby causing detrimental effects on ComEd's and PECO's operations. ComEd and PECO take steps to reduce extreme peak demand by implementing a number of programs, such as demand response and energy efficiency programs that will help to defer the need for additional transmission and distribution investment and support system reliability. In addition, ComEd and PECO analyze and plan using worst case scenarios and incorporate contingencies into their planning for extreme weather conditions.

Generation's operations are also affected by weather, both in terms of demand for electricity and in operating conditions. The effects of unusually warm or cold weather on Generation's results of operations depend on the nature of its market position at the time of the unusual weather. Generation plans its business based upon normal weather assumptions while performing analysis and necessary planning for severe weather driven scenarios. To the extent that weather is warmer in the summer or colder in the winter than assumed, Generation may require greater resources to meet its contractual requirements. Extreme weather conditions or storms may affect the availability of generation and transmission capacity, limiting Generation's ability to source or deliver power to where it is needed. These conditions, which cannot be reliably predicted, may have an adverse effect by requiring Generation to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when those markets are weak. Generation 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.

Additionally, Exelon is affected by the occurrence of extreme weather events such as hurricanes and storms in its service territories and throughout the United States. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within Exelon's service areas can also directly affect Exelon's capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. Finally, climate change could affect the availability of a secure and economical supply of water in some locations, which is essential for Exelon's continued operation, particularly the cooling of generating units. Exelon is engaged in several projects to identify opportunities for increasing water use efficiency, reducing water supply vulnerabilities and reducing water supply costs.

Climate Change Legislation. 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 have been introduced in Congress that address climate change from different perspectives, including a cap on carbon emissions with emitters allowed to trade unused emission allowances (cap-and-trade), a tax on carbon emissions and incentives to develop low-carbon technology. In addition to potential Federal legislation to directly regulate GHG emissions, it is possible that Congress may also consider other legislation with perceived GHG reduction benefits such as the establishment of Federal renewable energy portfolio standards (RPS).

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 June 2008, the Senate failed to pass the Lieberman-Warner America's Climate Security Act, which would have created an economy-wide cap-and-trade program. The America's Climate Security Act would reduce emissions by 70% from 2005 levels from covered sources by 2050, create a Carbon Market Efficiency Board to control costs of the program and initially auction 26.5% of the allowances rising to 69.5% in 2031. The bill gives 19% of the allowances to electric generators based on their heat input and 9% of allowances to electric local distribution companies for the benefit of their customers. The allowances to generators phase out to zero by 2031. Multiple bills were introduced in the House of Representatives but no action was taken on any of them either in the Energy and Commerce Committee or by the full House of Representatives. In late 2008, then-Chairman Dingell released a discussion draft for cap-and-trade legislation with Representative Boucher. The discussion draft would reduce emissions by 80% from 2005 levels by 2050. The discussion draft presented four options for how to allocate allowances. President Obama has stated that he favors climate legislation that would reduce greenhouse gas emissions by 80% by 2050 and that he prefers that 100% of allowances be auctioned.

Legislative efforts in Illinois and Pennsylvania related to climate change have focused primarily on energy efficiency, demand response and renewable energy initiatives. The Illinois Settlement Legislation enacted in 2007 requires electric utilities to use cost-effective energy efficiency resources to meet specific incremental annual energy savings goals. The Illinois Settlement Legislation also requires procurement plans of electric utilities in Illinois to include cost-effective renewable energy resources that meet a defined portion of total electricity supplied to retail customers. In Pennsylvania, the Alternative Energy Portfolio Standards Act of 2004 (AEPS Act) mandated that, beginning in 2007 or at the end of an electric distribution company's restructuring period, specified percentages of electric energy sold by the electric distribution company or the electric generation supplier to Pennsylvania retail electric customers must come from alternative energy resources. The Pennsylvania Climate Change Act (PCCA) was also signed into law in July 2008. The PCCA requires, among other things, that a Climate Change Advisory Committee be formed, that a report on the potential impact of climate change in Pennsylvania be developed, that the Pennsylvania Department of Environmental Protection (PA DEP) develop a GHG inventory for Pennsylvania, that a voluntary GHG registry be identified, and that 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. In October 2008, Act 129 became effective and requires that Pennsylvania electric utility companies meet energy-conservation and demand-reduction targets, beginning in 2011, to enhance Pennsylvania's energy independence and enable programs to help consumers manage their energy use.

On April 2, 2007, the U.S. Supreme Court issued a decision in the case of Massachusetts v. U. S. Environmental Protection Agency holding that CO_2 and other GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. The case was remanded to the EPA for further rulemaking to determine whether GHG emissions may reasonably be anticipated to endanger public health or welfare, or in the alternative provide a reasonable explanation why GHG emissions should not be regulated. Possible outcomes from this decision include regulation of GHG emissions not only from motor vehicles but also from manufacturing plants, including electric generation, transmission and distribution facilities, under a new EPA rule and Federal or state legislation. In response to the Supreme Court decision, on July 11, 2008, the EPA issued an Advance Notice of Proposed Rulemaking (ANPR) and is currently considering public comments made on analyses and policy alternatives regarding GHG effects and regulation under the Clean Air Act. This deferred any regulation of GHGs under the Clean Air Act. The issue of GHG regulation will likely be addressed in the new presidential administration, whether by regulation under the Clean Air Act or by new and comprehensive Federal legislation. Due to the uncertainty as to any of these potential outcomes, Exelon cannot estimate the effect of the decision on its operations and its future competitive position, results of operations, earnings, cash flows and financial position.

At a regional level, on August 24, 2005, the Regional Greenhouse Gas Initiative (RGGI), a cooperative effort by Northeastern and Mid-Atlantic states to reduce CO_2 emissions, released a program proposal. The RGGI Memorandum of Understanding (MOU) is an agreement to stabilize aggregate CO_2 emissions from power plants in participating states at current levels from 2009 to 2015. Reductions from current levels would be required to be phased in starting in 2016 such that by 2019 there would be a 10% reduction in participating state power plant CO_2 emissions. As of December 31, 2008, states participating in the RGGI MOU include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont. On August 15, 2006, the RGGI model rule was finalized, and RGGI member states that have not already done so are currently in the process of adopting state-level rules to implement the program starting in 2009. On September 26, 2008, six of the ten RGGI states participated in the first auction of CO_2 allowances under the program. Approximately 12.5 million tons of CO_2 allowances were auctioned. Generation owns a small amount of affected peaking and intermediate generating capacity in the RGGI region, including Maine, Massachusetts and New Jersey. On November 15, 2007, six Midwest state Governors (Illinois, Iowa, Kansas, Michigan,

Minnesota, Wisconsin) signed the Midwestern Greenhouse Gas Accord (the Accord). Under the Accord, an inter-state work group is to be 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). All undertakings of the Accord are to be completed within 30 months after its effective date, including the development of a proposed cap-and-trade agreement and model rule within 12 months.

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. The United States is expected to participate in this process. Recommendations will be reviewed at the UNFCCC meeting in 2009.

At this time, Exelon is unable to predict the potential impacts of any future mandatory governmental GHG legal or regulatory requirements on its businesses.

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 intensity and the absence of a mandatory national program in the United States, Exelon is actively engaged in voluntary reduction efforts. Exelon announced on May 6, 2005 that it had established a voluntary goal to reduce its GHG emissions by 8% from 2001 levels by the end of 2008. The 8% reduction goal represents a decrease of an estimated 1.3 million metric tons of GHG emissions. Exelon has incorporated recognition of GHG emissions and their potential cost into its business analyses as a means to promote internal investment in activities that produce fewer GHG emissions. Exelon made this pledge under the EPA's Climate Leaders program, a voluntary industry-government partnership addressing climate change. As of December 31, 2008, Exelon had achieved its 2008 voluntary GHG reduction goal through its planned GHG management efforts, including the previous closure of older, inefficient fossil-fueled power plants, reduced leakage of SF_6 and methane, increased use of renewable energy and its energy efficiency initiatives. The cost of achieving the voluntary GHG emissions reduction goal did not have a material effect on Exelon's future competitive position, results of operations, earnings, financial position or cash flows.

On July 15, 2008, Exelon announced a comprehensive business and environmental plan. The plan, Exelon 2020, details an enterprise-wide approach and a host of initiatives being pursued by Exelon to reduce Exelon's GHG emissions and that 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, which is more than Exelon's current annual carbon footprint.

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. Initiatives to reduce Exelon's own carbon footprint include reducing building energy consumption by 25%, reducing the 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 new portfolio of energy efficiency programs, a similar portfolio of energy efficiency programs in development at PECO to meet the requirements of the recently enacted PA 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. Finally, Exelon will offer more low-carbon electricity in the marketplace by increasing its investment in renewable power, adding capacity to existing nuclear plants through uprates, and through the potential addition of new low-carbon natural gas and nuclear generation.

Exelon is committed to achieving the Exelon 2020 goal but also recognizes that the changing economy and market outlook may require it to refine or alter the timing of some of these initiatives and update the 2020 roadmap accordingly. The anticipated economic stimulus package currently being considered in Congress and other new energy policies will also likely have an impact on initiatives under the plan.

Exelon has incorporated Exelon 2020 into the company's 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. 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.

(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 30, 2009, there were 658,242,488 shares of common stock outstanding and approximately 139,903 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:

	2008				2007			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$65.55	$91.64	$90.92	$86.52	$86.83	$82.60	$79.38	$72.31
Low price	45.00	61.16	82.22	73.04	73.76	64.73	68.67	58.74
Close	55.61	62.62	89.96	81.27	81.64	75.36	72.60	68.71
Dividends	0.525	0.500	0.500	0.500	0.440	0.440	0.440	0.440

The attached table gives information on a monthly basis regarding purchases made by Exelon of its common stock during the fourth quarter of 2008.

Period	Total Number of Shares Purchased [a]	Average Price Paid per Share	Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs [b]	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 1—October 31, 2008	11,221	$65.48	—	[b]
November 1—November 30, 2008	—	—	—	[b
December 1—December 31, 2008	1,998	64.83	—	[b]
Total	13,219	65.38	—	[b]

(a) Shares other than those purchased as a part of a publicly announced plan primarily represent restricted shares surrendered by employees to satisfy tax obligations arising upon the vesting of restricted shares.

(b) In April 2004, Exelon's Board of Directors approved a discretionary share repurchase program that allows Exelon to repurchase shares of its common stock on a periodic basis in the open market. The share repurchase program is intended to mitigate, in part, the dilutive effect of shares issued under Exelon's employee stock option plan and Exelon's Employee Stock Purchase Plan. The aggregate 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 Employee Stock Purchase Plan. The economic benefit consists of direct cash proceeds from purchases of stock and tax benefits associated with exercises of stock options. The 2004 share repurchase program has no specified limit and no specified termination date.

In addition, on August 31, 2007 and December 19, 2007, Exelon's Board of Directors approved share repurchase programs for up to $1.25 billion and $500 million, respectively, of Exelon's outstanding common stock in connection with Exelon's value return policy, which uses share repurchases from time to time to return cash or balance sheet capacity to Exelon shareholders after funding maintenance capital and other commitments and in the absence of higher value-added growth opportunities.

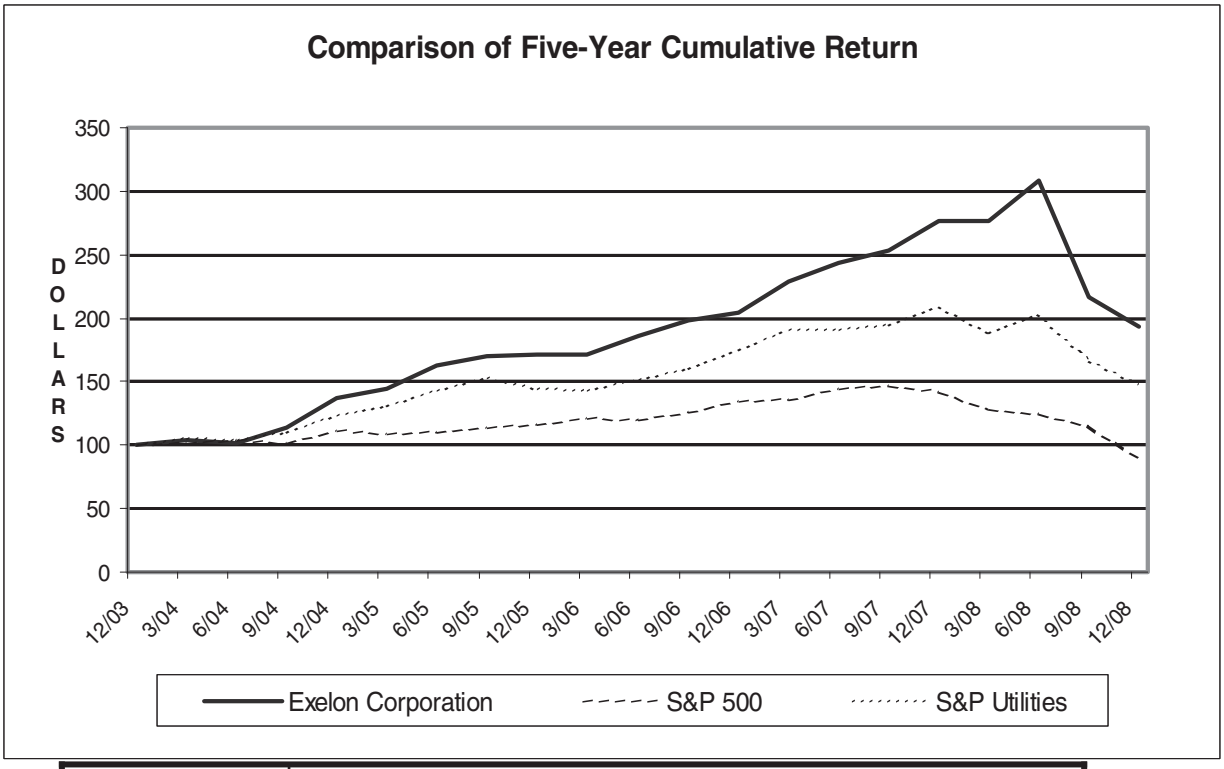
See Note 16 of the Notes to Consolidated Financial Statements for additional information regarding Exelon's share repurchase programs.

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 Corporation common stock, as compared with the Standard and Poor's (S&P) 500 Stock Index and the S&P Utility Index for the period 2004 through 2008.

This performance chart assumes:

- $100 invested on December 31, 2003 in Exelon Corporation 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,					
	2003	2004	2005	2006	2007	2008
Exelon Corporation	$100.00	$137.35	$170.89	$204.60	$276.34	$193.78
S&P 500	$100.00	$110.84	$116.27	$134.60	$141.98	$89.53
S&P Utilities	$100.00	$124.24	$144.88	$175.26	$209.14	$148.64

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 stock. At December 31, 2008, such capital was $2.7 billion and amounted to about 31 times the liquidating value of the outstanding preferred stock 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 PECO Energy Capital, L.P. (PEC L.P.) or PECO Energy Capital Trust IV (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, 2008, Exelon had retained earnings of $6.8 billion, including Generation's undistributed earnings of $2,323 million, ComEd's retained earnings of $170 million consisting of an unappropriated retained earnings of $1,809 million, partially offset by $(1,639) million of retained deficits appropriated for future dividends and PECO's retained earnings of $389 million.

The following table sets forth Exelon's quarterly cash dividends per share paid during 2008 and 2007:

	2008				2007			
(per share)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Exelon	$0.525	$0.500	$0.500	$0.500	$0.440	$0.440	$0.440	$0.440

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

	2008				2007			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$301	$253	$302	$689	$261	$1,431	$370	$295
PECO	98	146	97	139	108	178	121	155

On January 27, 2009, 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, 2009, to shareholders of record of Exelon at the end of the day on February 13, 2009. This dividend declaration was made by the Exelon Board of Directors under a value return policy that established a base dividend that Exelon expects will grow modestly over time. The value return policy contemplates the use of share repurchases from time to time, when authorized by the Board of Directors, to return cash or balance sheet capacity to Exelon shareholders after funding maintenance capital and other commitments and in the absence of higher value-added growth opportunities.

During 2008, 2007, and 2006, ComEd did not pay a dividend in order to manage cash flows and its capital structure. On January 26, 2009, the ComEd board declared a dividend of $0.472 per share on its common stock. ComEd's Board of Directors will continue to assess ComEd's ability to pay a dividend in future periods.

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.

	For the Years Ended December 31,				
in millions, except for per share data	**2008**	**2007**	**2006**	**2005**	**2004**
Statement of Operations data:					
Operating revenues	$18,859	$18,916	$15,655	$15,357	$14,133
Operating income	5,299	4,668	3,521	2,724	3,499
Income from continuing operations	$ 2,717	$ 2,726	$ 1,590	$ 951	$ 1,870
Income (loss) from discontinued operations	20	10	2	14	(29)
Income before cumulative effect of changes in accounting principles	2,737	2,736	1,592	965	1,841
Cumulative effect of changes in accounting principles (net of income taxes)	—	—	—	(42)	23
Net income [(a)]	$ 2,737	$ 2,736	$ 1,592	$ 923	$ 1,864
Earnings per average common share (diluted):					
Income from continuing operations	$ 4.10	$ 4.03	$ 2.35	$ 1.40	$ 2.79
Income (loss) from discontinued operations	0.03	0.02	—	0.02	(0.04)
Cumulative effect of changes in accounting principles (net of income taxes)	—	—	—	(0.06)	0.03
Net income	$ 4.13	$ 4.05	$ 2.35	$ 1.36	$ 2.78
Dividends per common share	$ 2.03	$ 1.76	$ 1.60	$ 1.60	$ 1.26
Average shares of common stock outstanding—diluted	662	676	676	676	669

(a) The changes between 2007 and 2006; 2006 and 2005; and 2005 and 2004 were primarily due to the impact of the goodwill impairment charges of $776 million and $1.2 billion in 2006 and 2005, respectively.

	December 31,				
in millions	**2008**	**2007 [(b)]**	**2006 [(b)]**	**2005 [(b)]**	**2004 [(b)]**
Balance Sheet data:					
Current assets	$ 5,368	$ 4,580	$ 4,214	$ 3,886	$ 3,578
Property, plant and equipment, net	25,813	24,153	22,775	21,981	21,482
Noncurrent regulatory assets	5,940	5,133	5,808	4,734	5,076
Goodwill [(a)]	2,625	2,625	2,694	3,475	4,705
Other deferred debits and other assets	8,071	8,870	7,974	7,910	7,748
Total assets	$47,817	$45,361	$43,465	$41,986	$42,589
Current liabilities	$ 4,080	$ 5,629	$ 4,977	$ 5,839	$ 4,522
Long-term debt, including long-term debt to financing trusts	12,592	11,965	11,911	11,760	12,148
Noncurrent regulatory liabilities	2,520	3,301	3,025	2,518	2,490
Other deferred credits and other liabilities	17,491	14,242	13,458	12,656	13,811
Minority interest	—	—	—	1	42
Preferred securities of subsidiary	87	87	87	87	87
Shareholders' equity	11,047	10,137	10,007	9,125	9,489
Total liabilities and shareholders' equity	$47,817	$45,361	$43,465	$41,986	$42,589

(a) The changes between 2006 and 2005 and between 2005 and 2004 were primarily due to the impact of the goodwill impairment charge of $776 million and $1.2 billion in 2006 and 2005, respectively.

(b) Exelon retrospectively reclassified certain assets and liabilities in accordance with FIN 39 as amended by FSP FIN 39-1.

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

Exelon

General

Exelon is a utility services holding company. It operates through subsidiaries in the following operating segments:

- ***Generation***, whose business consists of its owned and contracted electric generating facilities, its wholesale energy marketing operations and competitive retail supply operations.
- ***ComEd***, whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission 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 Notes to Consolidated Financial Statements for segment information.

Exelon's corporate operations, some of which are performed through its business services subsidiary, Exelon Business Services Company, LLC (BSC), provide Exelon's business segments 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. Exelon's net income was $2,737 million in 2008 as compared to $2,736 million in 2007 and diluted earnings per average common share were $4.13 for 2008 as compared to $4.05 for 2007.

The following factors contributed to an increase in net income:

- higher average realized margins at Generation;
- net mark-to-market gains on economic hedging activities;
- increased transmission and delivery service revenue at ComEd in 2008 resulting from the 2007 transmission and distribution rate cases;
- the impact of the decreased charges in 2008 associated with the 2007 Illinois Settlement; and
- a 2007 loss associated with Generation's tolling agreement with Georgia Power related to the contract with Tenaska

Offsetting these factors above are the following decreases in net income:

- net unrealized and realized losses on Generation's nuclear decommissioning trust funds related to the former AmerGen nuclear generating units and the unregulated portions of the Peach Bottom nuclear generating units (Unregulated Units);
- increased allowance for uncollectible accounts expense;
- income associated with investments in synthetic fuel-producing facilities in 2007; and
- the impact of the termination of Generation's PPA with State Line in 2007.

See Exelon Corporation—Results of Operations for further information regarding the changes in net income.

Economic Environment. As the economic environment has worsened, Exelon, Generation, ComEd and PECO (collectively, the Registrants) have performed additional assessments to determine the impact, if any, of recent market developments, including the bankruptcy, restructuring or merging of certain financial and energy companies, on the Registrants' financial statements. The Registrants' additional assessments have included a review of macroeconomic conditions, access to liquidity in the capital and credit markets, counterparty creditworthiness, value of the Registrants' investments (particularly in the employee benefit plans and nuclear

decommissioning trust funds) and exposure to other risks. The recent unprecedented volatility in the economy may create additional risks in the upcoming months and possibly years.

- Macroeconomic conditions

U.S. and global economic conditions worsened significantly in the last quarter of 2008. The stress caused to international credit markets, initially driven in large part by the devaluation of risky U.S. subprime debt, led to a dramatic tightening in liquidity. The U.S. government has responded with several initiatives to alleviate the strain on the financial markets. While these programs have had some positive effects on financial systems, credit remains tight and economic conditions in the U.S. and globally have continued to deteriorate.

The slowdown, initially led by housing declines in specific regional markets, has spread to encompass almost the entire U.S. economy. Both industrial production and consumer spending have fallen sharply in the last half of 2008, while the U.S. unemployment rate has increased. As a result of the decline in economic output, energy demand in ComEd's and PECO's service territories is lower, which has led to reduced sales to industrial, commercial and residential customers. Lower demand for electricity may also lead to lower margins for Exelon's wholesale fleet, although this effect will be mitigated in the short term by Exelon's hedging policies. In addition, customers may not be able to pay, or may delay payment of their utility bills. Management has taken steps to mitigate this risk through heightened collection efforts.

In addition, the world slowdown in economic activity has reduced demand for oil, coal and natural gas, and has led to sharply falling commodity prices. By the end of 2008, Eastern coal, oil and gas were trading at less than half of their prices at the summer peak. As a result, wholesale electricity prices in the U.S. have fallen. Due to Exelon's hedging policies, as described in Quantitative and Qualitative Disclosures About Market Risk, it has had limited exposure to lower power prices in the short term; however, prolonged lower commodity prices would adversely impact Exelon's results of operations in the future.

- Liquidity in the capital and credit markets

The Registrants believe they have sufficient liquidity despite the disruption of the capital and credit markets. The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flow from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities ($7.3 billion in aggregate total commitments with $6.9 billion available as of December 31, 2008, of which no financial institution, assuming announced consolidations, has more than 10% of the aggregate commitments for Exelon, Generation and PECO and 12% for ComEd). Generation and ComEd also have additional letter of credit facilities used solely to enhance tax-exempt variable rate debt. Certain of these letters of credit will expire in 2009 ($311 million and $194 million at Generation and ComEd, respectively), which the Registrants plan to extend or substitute. See "Variable-Rate Debt" within Liquidity and Capital Resources for further detail on these credit facilities.

While not significant to the Registrants to date, the disruptions in capital and credit markets may result in increased borrowing costs associated with short-term and long-term debt. The Registrants accelerated a number of bond issuances in 2008 in order to limit the risk of volatility in the credit markets and to enhance liquidity. As more fully discussed in "Liquidity and Capital Resources", the Registrants completed all their long-term financings planned for 2008. With the exception of debt to unconsolidated financing affiliates, the Registrants have $29 million of debt maturing in 2009 ($12 million and $17 million at Generation and ComEd, respectively) and $613 million of debt maturing in 2010 ($400 million and $213 million at Exelon Corporate and ComEd, respectively). The debt to unconsolidated financing affiliates at PECO is repaid through the collection of competitive transition charges from customers as allowed by restructuring legislation that was adopted in Pennsylvania in 1996.

The Registrants routinely review liquidity sufficiency, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements and the impacts of hypothetical credit downgrades. Management continues to closely monitor events and the financial institutions associated with its 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 2008 Form 10-K for information regarding the effects of a longer-term disruption in the capital and credit markets or significant bank failures.

- Counterparty creditworthiness

The Registrants are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations or the potential non-performance of counterparties to deliver contracted commodities or services at the contracted price. Generation's power-marketing activities are governed by risk management policies limiting transactions to a diversified group of high quality counterparties. During 2008, the bankruptcy of Lehman Brothers Holdings Inc. and the weakening of companies within the

energy industry have underscored the importance of these risk management practices. Although Generation's credit exposure was predominately with investment grade companies at December 31, 2008, changes in forward market prices could have a disproportionate impact to the percentage of credit exposure with non-investment grade companies. As of December 31, 2008, the net exposure after credit collateral for Generation's commodity contracts of $1,143 million included $1,119 million of exposure to investment-grade companies and $24 million of exposure to non-investment grade companies, primarily in the coal supply industry. As a result of management's review of Generation's counterparties, the direct net exposure of $22 million to Lehman Brothers Commodity Services Inc., a counterparty in wholesale energy marketing transactions, was fully reserved and charged to expense in the third quarter of 2008. As further discussed below, Generation also currently procures uranium concentrates through long-term contracts. Approximately 60% of the requirements from 2009 through 2013 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. Management continues to closely monitor the status of Generation's counterparties and will take action, as appropriate, to further manage its counterparty credit risk.

Under the Illinois Settlement Legislation, ComEd procures power through supplier forward contracts, standard block energy purchases, and spot market purchases. Collateral postings are required only of suppliers for the supplier forward contracts that ComEd entered into with winning suppliers from the Illinois auction, including Generation. The standard block energy purchases require collateral postings from both ComEd and the counterparty suppliers, including Generation, should exposures between forward market prices and benchmark price levels exceed established unsecured credit limits outlined in the agreements. In the event the counterparties fail to perform, ComEd might be forced to purchase power through an RFP process or in the spot markets at less favorable prices. As of December 31, 2008, there was no cash collateral or letters of credit posted between suppliers and ComEd. The potential failure of energy suppliers to perform is mitigated by ComEd's ability to recover its actual costs to procure power as stipulated in the Illinois Settlement Legislation as well as the ICC-approved procurement tariff.

PECO has counterparty credit risk related to its electricity and natural gas suppliers. Generation provides 100% of PECO's electric energy under a purchase power agreement (PPA). There are no collateral posting provisions included in PECO's electric supply agreement with Generation. PECO procures natural gas from suppliers under both short-term and long-term contracts. The potential failure of natural gas suppliers to perform is mitigated by PECO's ability to seek recovery of its actual costs to procure natural gas through the PAPUC's purchased gas cost clause, subject to PAPUC review. A further discussion of counterparty risk is included in Quantitative and Qualitative Disclosures about Market Risk.

- Value of investments (particularly in employee benefit plan trusts and nuclear decommissioning trust funds)

Exelon sponsors defined benefit pension plans and postretirement benefit plans for the employees of the Registrants. The Registrants believe that the oversight of the investments held under Exelon's employee benefit plans is rigorous and that the investment strategies are prudent. The market value of the investments within the employee benefit plan trusts declined by approximately 26% during the year ended December 31, 2008. The benefit plan assets and obligations of Exelon and AmerGen are remeasured annually using a December 31 measurement date. Reductions in plan assets from investment losses during 2008 was a significant driver contributing to an increase of approximately $3.9 billion to the plans' unfunded status upon actuarial revaluation of the plan on December 31, 2008. Changes in the value of plan assets did not have an impact on the income statement for 2008; however, the change in value resulted in an after-tax reduction of shareholders' equity of approximately $1.5 billion. Reduced benefit plan assets are expected to result in increased benefit costs and required funding contributions in future years. Such increases could be material to 2009 and subsequent years. Exelon estimates that pension and other postretirement benefits expense will total approximately $425 million in 2009 as compared to approximately $240 million in 2008. See Critical Accounting Policies for additional information regarding the potential impacts of declines in the return on benefit plan assets that is less than assumed and Liquidity and Capital Resources for information regarding future funding requirements.

Nuclear decommissioning trust funds have been established on a unit-by-unit basis to satisfy Generation's nuclear decommissioning obligations. Currently, Generation is making contributions only to the trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to Generation. While Generation has recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds) with respect to the former PECO units, it has no recourse to collect additional amounts from ComEd customers for the former ComEd units or from the previous owners of the AmerGen plants, if there is a shortfall of funds necessary for decommissioning. Generation believes that its oversight of these trust funds is rigorous and the investment strategy is prudent. At December 31, 2008, approximately 39% of the funds were invested in equity and 61% were invested in fixed income securities, with limitations related to concentration and investment grade ratings. See Note 12 of the Notes to Consolidated Financial Statements for the amounts of unrealized losses on the trust funds during the year ended December 31, 2008. Nuclear Regulatory Commission (NRC) regulations require that licensees of nuclear generating facilities

demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. Generation is required to provide to the NRC a biennial report by unit (annually for Generation's five units that have been retired or are within five years of the current approved license life) addressing Generation's ability to meet the NRC-estimated 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 making 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 positions may be significantly adversely affected. Generation's next report to the NRC is due on March 31, 2009, based on trust fund values and estimated decommissioning obligations as of December 31, 2008. Based on these values, six units at three nuclear generating stations were in an underfunded position by approximately $185 million in total at December 31, 2008, relative to the NRC minimum funding requirements. Exelon and Generation currently are evaluating the remedy that will be used to address the underfunded status. See PART I. ITEM 1A. Risk Factors of Exelon's 2008 Form 10-K for information regarding the effects of a longer-term disruption in the capital and credit markets or significant bank failures.

Based on a regulatory agreement with the ICC that applies to the former ComEd nuclear generating units on a unit-by-unit basis, as long as funds held in the nuclear decommissioning trust funds exceed the total estimated decommissioning obligation, decommissioning impacts recognized in the Consolidated Statement of Operations, including realized and unrealized income and losses of the trust funds and accretion of the decommissioning obligation, are generally offset within Exelon's and Generation's Consolidated Statements of Operations. Should the trust funds for the former ComEd units continue to experience declines in market value such that the value of the trust funds for any unit falls below the amount of the estimated decommissioning obligation for that unit, the accounting to offset decommissioning impacts in the Consolidated Statement of Operations for that unit would be discontinued, the decommissioning impacts would be recognized in the Consolidated Statements of Operations and the adverse impact to Exelon's and Generation's results of operations and financial positions could be material. At December 31, 2008, the trust fund investment values for each of the former ComEd units exceeded the related decommissioning obligation for each of the units. See Note 12 of the Notes to Consolidated Financial Statements for additional information regarding the accounting for the former ComEd nuclear generating units as a result of the ICC order.

The Registrants engage in a securities lending program with respect to the investments within their employee benefit plan trusts and nuclear decommissioning trust funds. In connection with this program, the securities loaned are supported by collateral posted by the borrowers, which the Registrants invest in a short-term collateral fund or in assets with maturities matching, or approximating, the duration of the loan of the related securities. The Registrants bear the risk of loss with respect to their invested cash collateral. Such losses may result from a decline in fair value of specific investments or due to liquidity impairments resulting from current market conditions. Losses recognized by the Registrants have not been significant to date. Exelon has invested collateral of $660 million as of December 31, 2008. Management continues to monitor the performance of the invested collateral and to work closely with the trustees to limit any potential further losses. In the fourth quarter of 2008, the Registrants decided to end their participation in the securities lending program and have chosen to initiate a gradual withdrawal of their participation in the securities lending program in order to avoid potential losses on invested cash collateral due to the lack of liquidity in the market. Currently, the weighted average maturity of the securities within the collateral pools is approximately 7.5 months. Exelon's withdrawal from the securities lending program based on the maturities of securities within the collateral pools is expected to result in the return of approximately 70% of its loaned securities (in terms of value) by the end of 2009, 94% by the end of 2010 and the return of the remaining securities by the end of 2011.

- Value of other assets

In the fourth quarter of 2008, ComEd assessed its goodwill for impairment and the analysis indicated that there was no impairment. However, the recent economic downturn and the capital and credit market crisis have impacted the market-related assumptions, resulting in a significant decrease in the estimated fair value of ComEd since the November 1, 2007 assessment. Further declines could result in an impairment and such a charge could be material. See Note 7 of the Notes to Consolidated Financial Statements for information regarding the goodwill impairment analysis.

Generation regularly evaluates the economic viability of its generating plants. Generation's plants continue to be economically viable, and Generation's review indicated there was no impairment as of December 31, 2008 under a held and used model. See Outlook for 2009 and Beyond—Proposal for acquisition of NRG for discussion of Generation's evaluation of its Texas generating plants for impairment in connection with the potential divestiture of these plants as a result of Exelon's proposed acquisition of NRG.

- Other risks

The Registrants have reviewed their exposure to insurance risk and have concluded that there have been no material changes related to the availability and cost of liability, property, nuclear risk, and other forms of insurance. Management continues to monitor closely events and the ratings for insurance companies associated with its insurance programs. Further declines in the market may have a significant adverse impact on the availability and cost of insurance.

Regulatory and Environmental Developments. The following significant regulatory and environmental developments occurred during 2008. See Notes 3 and 18 of the Notes to Consolidated Financial Statements for additional information.

Exelon

- Exelon surpassed its U.S. EPA Voluntary Climate Leaders goal announced on May 5, 2005 to reduce its GHG emissions by 8% from 2001 levels by the end of 2008. The GHG management efforts undertaken in support of the goal, including the previous closure of older, inefficient fossil power plants, reduced leakage of SF_6, increased use of renewable energy and its current energy efficiency initiatives, yielded greater than expected reductions. Exelon is in the process of having its GHG reductions verified by a third party and endorsed by U.S. EPA. While Exelon met its goal, on July 15, 2008, Exelon announced a new longer-term comprehensive environmental plan, Exelon 2020.

ComEd

- Delivery Service Rate Case—On September 10, 2008, the ICC issued its final order in ComEd's rate case proceeding that was initiated in October 2007. The order approved an increase in the annual revenue requirement of $274 million, which became effective on September 16, 2008.
- Transmission Rate Case—On January 16, 2008, FERC approved an annual transmission network service revenue requirement for ComEd of approximately $390 million, effective May 1, 2007. The revenue requirement represented an increase of approximately $93 million and was based on a newly approved formula rate model.

  On May 15, 2008, ComEd filed its first annual formula update filing, which updates ComEd's formula rate to include actual 2007 expenses and capital additions plus forecasted 2008 capital additions. The update resulted in a revenue requirement of $430 million, plus an additional $26 million related to the 2007 true-up of actual costs for a total increase of approximately $66 million, which became effective for the period June 1, 2008 through May 31, 2009.

PECO

- Gas Distribution Rate Case—During 2008, PECO filed a petition before the PAPUC for a $98 million rate increase. On October 23, 2008, the PAPUC approved a settlement of a distribution rate increase that provides for an annual revenue increase of $77 million. The approved distribution rate adjustment became effective on January 1, 2009.
- PECO AEPS Filing—In August 2008, PECO entered into a five-year agreement with an accepted bidder to purchase Alternative Energy Credits (AECs) from the March 2008 RFP. PECO launched its second RFP in November 2008 and anticipates entering into fixed-price, five-year agreements by March 2009, with purchases beginning no later than December 31, 2009.
- PECO Default Service Filing—On November 14, 2008, PECO amended its comprehensive Default Service Program and Rate Mitigation Plan with the PAPUC relating to its plan to provide default electric service following the expiration of rate caps on December 31, 2010. The purpose of the amendment was to address the requirements of Act 129 of 2008 (Act 129), which was signed into law in October 2008. PECO has withdrawn its Energy Efficiency Package and will revise its energy efficiency programs consistent with the new requirements of Act 129. The PAPUC will conduct a formal proceeding to give all interested parties the opportunity to examine aspects of the amended filing and make independent recommendations. The process is expected to be completed by July 2009.

Outlook for 2009 and Beyond.

Several significant events may occur during the rest of 2009 and beyond, including the following:

Proposal for acquisition of NRG

- On October 19, 2008, with authorization from Exelon's Board of Directors, Exelon submitted a proposal to NRG to enter into a business combination with NRG under which Exelon would exchange 0.485 of a share of Exelon common stock for each share of NRG common stock. On November 12, 2008, Exelon announced an exchange offer in which Exelon, through its wholly owned subsidiary Exelon Xchange, offered to acquire all of the outstanding NRG common stock in exchange for 0.485 of a share of Exelon common stock plus cash in lieu of fractional shares, representing a total equity value of approximately $6.2 billion for NRG based on Exelon's closing price on October 17, 2008. On January 7, 2009, Exelon announced that the initial expiration of the offer on January 6, 2009, NRG shareholders had tendered approximately 106 million shares of common stock of NRG, representing just over 45.6% of all outstanding shares of NRG common stock, and Exelon was extending the expiration date of the exchange offer until 5:00 PM New York City Time on February 25, 2009 unless further extended. Exelon is taking steps to obtain the regulatory approvals required for the proposed acquisition of NRG. NRG rejected Exelon's initial offer and remains opposed to Exelon's exchange offer. See General Description of Our Business for further information.

  As part of its FERC filing related to the NRG offer to address potential market power concerns, Exelon proposed to divest its three facilities in Texas – Mountain Creek, Handley and LaPorte – totaling approximately 2,400 MW of capacity. The plans also include transferring to a third party Exelon's power purchase agreements in Texas totaling approximately 1,200 MW of capacity. In addition, the combined company would divest approximately 1,000 MW of capacity in the PJM East market, including plants currently owned by NRG. Exelon does not believe there are any other generation overlap issues related to the proposed combination.

  In connection with the decline in current market conditions and the potential divestiture of the Texas plants proposed in its December 2008 FERC filing, Generation evaluated its Texas plants for potential impairment as of December 31, 2008 pursuant to SFAS No. 144. The impairment evaluation was performed to assess whether the carrying values of the plants were not recoverable. Although energy market conditions have deteriorated since mid-2008, in part reflecting lower commodity prices, which could have an adverse impact on the potential sales price of these plants; Generation's evaluation indicated that the estimated undiscounted cash flows exceeded the carrying values of the plants and an impairment did not exist as of December 31, 2008 under the held and used model of SFAS No. 144. As Exelon continues its efforts to acquire NRG, Generation will continue to evaluate its Texas plants for impairment, taking into account current energy market conditions, the likelihood and timing of the divestiture of these plants and the potential sales proceeds that might be obtained. Should current market conditions further decline or the likelihood of divestiture increase, an impairment may be triggered and any potential impairment of its Texas plants could have a material adverse impact on Exelon's and Generation's results of operations in the period in which the impairment is recorded.

Pennsylvania Transition Legislation

- PECO is subject to caps on its electric generation rates through December 31, 2010 in connection with its PPA with Generation. In Pennsylvania, despite the decrease during 2008 in wholesale electricity market prices, legislators and regulators have still expressed concern regarding the rate increases expected in the transition to market-based retail electric generation rates. Although recently enacted Act 129 provides guidelines associated with electricity procurement that support competitive, market-based procurement, elected officials have suggested rate-cap extensions, rate-increase deferrals and phase-ins, a generation tax and contributions of value (potentially billions of dollars statewide) by Pennsylvania utility companies toward rate-relief programs that could have a significant impact on PECO and Generation.

  Act 129 requires that Pennsylvania electric utility companies meet energy-conservation and demand-reduction targets, beginning in 2011, to enhance the Commonwealth's energy independence and enable programs to help consumers manage their energy use. In 2009, PECO will file plans with the PAPUC to meet these energy-efficiency and demand-response goals. Also, PECO will be required to transition its electric customers to smart-meter technology over a fifteen-year period and to make available time-of-use rates and real-time price plans. The legislation allows recovery of costs for each of these programs, subject to approval by the PAPUC.

Presidential Administration

- Due to the new Democratic Administration and increased Democratic majorities in the U.S. House of Representatives and U.S. Senate, there is a stronger likelihood that legislation related to energy, environmental and tax policy will be enacted in the

foreseeable future. These changes may include, but are not limited to, legislation or regulation limiting GHG emissions; changing corporate tax law; a higher tax on dividend income; the Federal imposition of a renewable energy portfolio standard; and incentives for investments in transmission, smart grid deployment, energy efficiency and renewable generation. Exelon continuously evaluates the potential impact of proposed public policy changes which may impact the Registrants either favorably or unfavorably.

New Growth Opportunities

- Generation pursues growth opportunities that are consistent with its disciplined approach to investing to maximize shareholder value, taking earnings, cash flow and financial risk into account. On September 2, 2008, Generation submitted a combined COL application to the NRC seeking authorization to build and operate a new dual unit nuclear generating facility in Victoria County in southeast Texas. In addition, Generation filed Part I and Part II of a loan guarantee application with the Department of Energy (DOE) for these potential new units on September 26, 2008 and December 18, 2008, respectively. The COL application preserves for Exelon and Generation the option to develop a new nuclear plant in Texas without immediately committing to the full project. In order to continue preserving and assessing this option, Exelon and Generation have approved expenditures on the project of up to $100 million, which includes fees and costs related to the COL, reservation payments and other costs for long-lead components of the project, and other site evaluation and development costs. Amounts spent on the project to date have been expensed. The development phase of the project is expected to extend into 2009, with approval of funding beyond the $100 million commitment subject to management review and board approval. Generation has not made a decision to build a new nuclear plant at this time. Among the various conditions that must be resolved before any formal decision to build is made by Generation are the successful granting of the COL by the NRC; significant progress to resolve questions around the short-term interim and long-term permanent storage, as well as potential future recycling, of spent nuclear fuel; broad public acceptance of a new nuclear plant; and assurances that a new plant can be financially successful, which would entail economic analysis that would incorporate assessing construction and financing costs, including the availability of sufficient financing, production and other potential tax credits, and other key economic factors. However, the decision to build the new nuclear plant depends, in large part, upon financial support under the DOE loan guarantee program. At this time, there is considerable uncertainty about the likelihood of DOE financial support for the project due to the limited appropriations available to DOE for this purpose and the number of projects competing for those limited resources.
- On May 1, 2008, Generation announced that it is actively pursuing the development of a 600-megawatt combined-cycle natural gas power plant in Pennsylvania. The new plant would advance Exelon's efforts to combat carbon emissions associated with electricity generation. Generation has been looking at several existing plant sites that it owns with access to the transmission lines, water and fuel needed to operate a new power plant. Generation has stated that a final decision on whether to move forward would be made only after it had more certainty around environmental permitting and had performed a more detailed economic review. Generation will continue to study the development of the project but will not make material investments or pursue permits until general market conditions have improved the estimated economic returns of the project. Amounts spent on the project to date, which are not material, have been expensed.

Illinois Settlement Legislation

- The legislation reflecting the agreement that ComEd, Generation and other generators and utilities in Illinois reached with various representatives from the State of Illinois (Illinois Settlement Legislation) is expected to provide ComEd with greater stability and certainty that it will be able to procure electricity and pass through the costs of that electricity to its customers with less risk that rate freeze or other harmful legislation will be pursued in the near term. As stipulated in the Illinois Settlement Legislation, the IPA, under the oversight of the ICC, is responsible for all procurement plans for annual delivery periods starting in June 2009 and thereafter. ComEd has stabilized a portion of its costs of procurement pursuant to the five-year financial swap contract with Generation. ComEd will be allowed to fully recover the costs of procuring energy, including the impacts of the financial swap contract, in its rates as it was deemed prudent by the Illinois Settlement Legislation. In the event that legislation is enacted in the Illinois General Assembly prior to August 1, 2011 that freezes or reduces electric rates or imposes a generation tax, the Illinois Settlement Legislation permits ComEd and Generation, as contributors to certain rate relief programs, to terminate their funding commitments to such programs.

Cost Savings

- Exelon anticipates that it will be subject to the ongoing pressures of rising operating expenses due to increases in costs, such as medical benefits and rising payroll costs due to inflation. Also, Exelon will continue to incur significant capital costs associated

with its commitment to produce and deliver energy reliably to its customers. Increasing capital costs may include the price of uranium, which fuels the nuclear facilities, and continued capital investment in Exelon's aging distribution infrastructure and generating facilities. Exelon is determined to operate its businesses responsibly and to appropriately manage its operating and capital costs while serving its customers and producing value for its shareholders. In 2009, Exelon will realize cost savings through sustainable productivity improvements. This effort will include the evaluation of Exelon's governance model to ensure its corporate cost structure is optimal in supporting the operating companies. In addition, Exelon will implement more rigorous planning and performance-measurement tools that allow it to better identify areas for productivity improvement across the operating companies and to measure progress against plan.

Competitive Markets

- In general, market prices for energy have increased over the past number of years due to the rise in natural gas and other fuel prices. As a result, PECO customers' generation rates generally have been below wholesale energy market prices in PJM, and Generation's margins on sales in excess of PECO's requirements generally have been higher during this time. Given its significance to Generation, the expiration at the end of 2010 of the current PPA with PECO could result in significant changes in margins earned by Generation beginning in 2011. Any increase or decrease in margin as a result of entering into new power supply contracts backed by the generation capacity previously committed to PECO will depend on a number of factors, including future wholesale market prices, energy demand and the outcome of Pennsylvania transition legislation. See "Pennsylvania Transition Legislation" above for more information.
- Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2009 and 2010. However, Generation is exposed to relatively greater commodity price risk in the subsequent years for which a larger portion of its electricity portfolio may be unhedged. Generation has estimated greater than 95% and 90% for economic and cash flow hedge ratios for 2009 and 2010, respectively, which includes cash flow and other derivatives, for its energy marketing portfolio. This financial hedge ratio is the estimate of the gross margin that is hedged given the current assessment of market volatility. Generation has been and will continue to be proactive in using hedging strategies to mitigate this risk in subsequent years as well.
- Generation procures coal through annual, short-term and spot-market purchases and natural gas through annual, monthly and spot-market purchases. Nuclear fuel assemblies are obtained through long-term contracts for uranium concentrates and through long-term contracts for conversion services, enrichment services and fuel fabrication services. Generation procures coal primarily through annual, short-term and spot-market purchases and natural gas through annual, monthly and spot-market purchases. 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 60% of Generation's uranium concentrate requirements from 2009 through 2013 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.

Environmental Matters

- On July 15, 2008, Exelon announced a new longer-term comprehensive environmental plan, Exelon 2020. See Note 18 of the Notes to Consolidated Financial Statements for results of Exelon's GHG emissions reduction plan and detail on the Exelon 2020 plan.
- The Clean Air Interstate Rule (CAIR) was promulgated by the EPA in 2005 to reduce power plant emissions of SO_2 and NO_x. On December 23, 2008, in response to a petition for re-hearing of its July 11, 2008 decision to vacate CAIR, the U.S. Court of Appeals for the District of Columbia Circuit determined not to vacate the existing CAIR pending issuance of a revised CAIR by the EPA. The Court's decision to allow CAIR to remain in effect will assist eastern states in continuing to improve regional air quality in support of meeting Federal air quality attainment dates. See Note 18 of the Notes to Consolidated Financial Statements for detail on the impact of the vacature of CAIR to Generation.

- On January 25, 2007, the U.S. Court of Appeals for the Second Circuit invalidated compliance measures of the final Phase II rule implementing Section 316(b) of the Clean Water Act. These measures 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. Several industry parties sought review by the Supreme Court and a decision is expected in the first half of 2009.

  On July 9, 2007, the EPA formally suspended the Phase II rule due to the uncertainty about the specific compliance requirements created by the court's remand of significant provisions of the rule. Until the EPA finalizes the rule on remand (which could take several years), 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. See Note 18 of the Notes to Consolidated Financial Statements for detail on the impact of this rule to Generation.

- Various stakeholders, including legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors, including utilities, are considering ways to address the climate change issue. Mandatory programs to reduce GHG emissions are likely to evolve in the future. If these plans become effective, Exelon may incur costs in limiting further the GHG emissions from its operations or in procuring emission allowance credits. However, Exelon may benefit from stricter emission standards due to its significant nuclear and other low-carbon capacity, which is not anticipated to be adversely affected by proposed GHG emission standards such as the Clean Air Act.

  On April 2, 2007, the U.S. Supreme Court issued a decision in the case of Massachusetts v. U. S. EPA holding that carbon dioxide (CO_2) and other GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. The case was remanded to the EPA for further rulemaking, and the possible outcomes from this decision could include regulation of GHG emissions from manufacturing plants, including electric generation, transmission and distribution facilities. See General Description of Our Business for further discussion.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States (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 within 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 in matters 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 Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations (ARO)

Generation must make significant estimates and assumptions in accounting for its obligation to decommission its nuclear generating plants in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143).

SFAS No. 143 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 which considers multiple outcome scenarios based upon significant estimates and assumptions embedded in the following:

Decommissioning Cost Studies. Generation uses decommissioning cost studies on a unit-by-unit basis 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 decommissioning period for each of the units. Cost escalation studies are used to determine escalation factors and are based on inflation indices for labor, equipment and materials, energy, low-level radioactive waste disposal and other costs. Cost escalation studies are updated on an annual basis.

Probabilistic Cash Flow Models. Generation's probabilistic cash flow models include the assignment of probabilities to various cost, decommissioning alternatives and timing scenarios on a unit-by-unit basis. Probabilities assigned to cost levels include an

assessment of the likelihood of actual costs plus 20% (high-cost scenario) or minus 15% (low-cost scenario) over the base cost scenario. Probabilities assigned to decommissioning alternatives assess the likelihood of performing DECON (a method of decommissioning in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed and safely buried in a low-level radioactive waste landfill or decontaminated to a level that permits property to be released for unrestricted use shortly after the cessation of operations), Delayed DECON (similar to the DECON scenario but with a 20-year delay) 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 spent nuclear fuel for disposal, which Generation currently estimates to begin in 2020. For more information regarding the estimated date that DOE will begin accepting spent nuclear fuel, see Note 13 of the Notes to Consolidated Financial Statements.

Discount Rates. The probability-weighted estimated future cash flows using these various scenarios are discounted using credit-adjusted, risk-free rates applicable to the various businesses in which each of the nuclear units originally operated.

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, 2008
Cost escalation studies	
Uniform increase in escalation rates of 25 basis points	$273
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	$ 97
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	$133
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	$220

If the estimated date for DOE acceptance of spent nuclear fuel were to be extended to 2025, Generation's aggregate nuclear decommissioning obligation would be reduced by an immaterial amount.

Under SFAS No. 143, the nuclear decommissioning obligation is adjusted on a regular basis due to the passage of time and revisions to either the timing or estimated amount of the future undiscounted cash flows required to decommission the nuclear plants. For more information regarding the application of SFAS No. 143, see Notes 1 and 12 of the Notes to Consolidated Financial Statements.

Nuclear Decommissioning Trust Fund Investments

The trust fund investments have been established to satisfy Exelon's and Generation's nuclear decommissioning obligations. The nuclear decommissioning trust 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. These policies restrict the trust funds from holding alternative investments and limit the trust funds' exposures to investments in highly illiquid markets. On January 1, 2008, Generation elected the fair value option under SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115" (SFAS No. 159) with respect to these investments; therefore, the investments are carried at fair value with all changes in fair value being recognized through the statement of operations.

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. For fixed income securities, the trustees receive multiple prices from pricing services, which enable cross-provider validations by the trustees 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 trustees challenge an assigned price and 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.

In accordance with SFAS No. 157, "Fair Value Measurements" (SFAS No. 157), Generation categorizes these investments under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. Investments with maturities of the three months or less when purchased are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2. 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 all actively traded securities due to the volume trading requirements imposed by these exchanges. In addition, 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 of similar securities, adjusted for observable differences and are categorized in 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, vintage, purpose of loan, collateral attributes, prepayment speeds, interest rates and credit ratings in order to properly value these securities. Commingled funds, which are analogous to mutual funds, are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. Short-term commingled funds held within the trust funds, which generally hold short-term fixed income securities, are categorized as Level 2 as the fair values of these funds are derived from observable prices, and these funds are not subject to restrictions regarding the purchase or sale of shares. The objectives of the remaining commingled funds in which Exelon and Generation invest primarily seek to track the performance of specific equity indices, specifically the Standard & Poor's (S&P) 500, the Russell 3000 and the Morgan Stanley Capital International EAFE indices, by purchasing equity securities to replicate the capitalization and characteristics of the indices. The fair value of these commingled funds primarily are based on net asset values per fund share (the unit of account), derived from the quoted prices in active markets of the underlying equity securities. However, because the shares of these commingled funds are not publicly quoted, not traded in an active market and are subject to certain restrictions regarding their purchase and sale, the commingled funds are categorized in Level 3. See Notes 8 and 12 of the Notes to Consolidated Financial Statements for further discussion on the nuclear decommissioning trust funds.

Asset Impairments

Goodwill

Exelon and ComEd have goodwill which relates to the acquisition of ComEd under the PECO/Unicom Merger. Under the provisions of SFAS No. 142, Exelon and ComEd perform assessments for impairment of their 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 a reporting unit below its carrying amount. 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. In general, fair value increases to assets and / or fair value decreases to liabilities would increase the size of any impairment. For example, a decrease in the fair value of ComEd's debt would increase the size of any impairment and vice versa. Application of the goodwill impairment test requires management judgment, including the identification of reporting units, assigning assets, liabilities and goodwill to reporting units, and determining the fair value of the reporting unit. See Note 7 of the Notes to Consolidated Financial Statements for additional information.

In the assessment, Exelon and ComEd estimate the fair value of the ComEd reporting unit using a probability-weighted, expected cash flow model with scenarios reflecting potential outcomes of future regulatory filings and management's associated plans, and a resulting range of operating results and cash flows. The model includes an estimate of ComEd's terminal value based on these expected cash flows and on an earnings multiple approach, which reflects the estimated value of comparable utility companies. Other significant assumptions used in estimating the fair value of the ComEd reporting unit include ComEd's capital structure, interest rates, utility sector market performance, operating and capital expenditure requirements, fair value of debt and other factors. This approach, including the comparable utility companies used to determine the earnings multiple, has been consistently applied since the adoption of SFAS No. 142. In addition, ComEd performs alternative market-based analyses to corroborate the estimated fair value, including a reconciliation of the sum of the fair value of all Exelon reporting units to its enterprise value based on its trading price.

The regulatory environment, such as the September 2008 Rate Order, has provided more certainty related to ComEd's future cash flows. However, the recent economic downturn and the capital and credit market crisis have significantly impacted the market-related assumptions, resulting in a significant decrease in the estimated fair value of ComEd since the November 1, 2007 assessment. For example, the earnings multiple used to determine the terminal value decreased from 8.6x at November 1, 2007 to 7.5x at November 1, 2008. While ComEd did not recognize an impairment in 2008, further deterioration of the market-related factors used in the impairment review could result in a future impairment loss of ComEd's goodwill, which could be material.

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. 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, 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. Impairment may occur when the carrying value of the asset exceeds the future undiscounted cash flows. When the undiscounted cash flow analysis indicates a long-lived asset is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its fair value. An impairment would require the affected Registrant to reduce both the long-lived asset and current period earnings by the amount of the impairment. See Note 5 of the Notes to Consolidated Financial Statements for a discussion of asset impairment evaluations made by Generation, including an evaluation made in connection with Exelon's proposed acquisition of NRG.

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. Changes to depreciation estimates in future periods could have a significant impact on the amount of depreciation expense recorded in the income statement.

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. 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. A change in depreciation estimates resulting from a change in the estimated end of service lives could have a significant effect on Generation's results of operations. Generation also periodically evaluates the estimated service lives of its fossil fuel and hydroelectric generating facilities based on feasibility assessments as well as economic and capital requirements. 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.

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. The completion of the depreciation study is expected to result in an increase to ComEd's annual depreciation expense of approximately $15 million during 2009.

PECO is required to file a depreciation rate study at least every five years with the PAPUC. In August 2005, 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 March 2006. The impact of the new rates was not material.

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. Employees of Generation's former wholly-owned subsidiary, AmerGen, participate in a separate AmerGen-sponsored defined benefit pension and other postretirement welfare benefit plans. Effective January 8, 2009, the AmerGen legal entity was merged into Generation. At that time, Exelon became the sponsor of all AmerGen pension and postretirement benefit plans. The change in sponsorship did not materially impact the funding or substantive provisions of the AmerGen plans. See Note 14 of the 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 these plans involve various factors, including numerous assumptions and accounting elections. When determining the various assumptions that are required, Exelon considers historical information as well as future expectations. The benefit costs are affected by, among other things, the actual rate of return on plan assets, the long-term expected rate of return on plan assets, the discount rate applied to benefit obligations, the incidence of mortality, the expected remaining service period of plan participants, level of compensation and rate of compensation increases, employee age, length of service, the long-term expected investment crediting rate, the anticipated rate of increase of health care costs and the level of benefits provided to employees and retirees. Pension and postretirement benefit costs attributed to the operating companies are included with labor costs and ultimately allocated to projects within the operating companies, some of which are capitalized.

Actual asset return experience has a significant effect on the costs reported for Exelon's and AmerGen's pension and postretirement benefit plans. The overall actual asset returns across the Registrant's pension and postretirement benefit plans for the year ended December 31, 2008 were a loss of approximately 26% compared to an assumed 8.75% positive return. This loss of 26% is expected to increase 2009 and 2010 benefit costs as follows:

	Increase in 2009 Pension Cost	Increase in 2009 Postretirement Benefit Cost	Increase in 2010 Pension Cost	Increase in 2010 Postretirement Benefit Cost
2008 negative asset returns of 26%	$110	$99	$176	$95

This information assumes that movements in asset returns occur absent changes to other actuarial assumptions, and does not consider any actions management may take to mitigate the impact of the asset return shortfalls, 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 increase in benefit costs set forth above.

In addition, declines in the value of plan assets during 2008 resulted in an increase to the plans' unfunded status and a decrease to shareholders' equity upon actuarial revaluation of the plan on December 31, 2008, and reduced benefit plan assets may increase the amount and accelerate the timing of required future funding contributions.

The pension and postretirement plan trusts investments include debt and equity securities, held directly and through commingled funds, and alternative asset classes. With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges. For fixed income securities, the trustees receive multiple prices from pricing services, which enable cross-provider validations by the trustees 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 trustees challenge an assigned price and determine that another price source is considered to be preferable. Additionally, Exelon selectively corroborates the fair values of securities by comparison to other market-based price sources. Commingled funds are valued based on the net asset value of the underlying assets, which are generally equity and fixed income securities. Alternative investments are valued by investment managers, generally using a model based approach. Exelon has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices.

The selection of key actuarial assumptions utilized in the measurement of the plan obligations and costs drives the results of the analysis and the resulting charges. The long-term expected rate of return on plan assets (EROA) assumption used in calculating pension cost was 8.75%, 8.75%, and 9.00% for 2008, 2007, and 2006, respectively. The weighted average EROA assumption used in calculating other postretirement benefit costs was 7.80%, 7.85%, and 8.15% in 2008, 2007, and 2006 respectively. A lower EROA

is used in the calculation of other postretirement benefit costs, as the other postretirement benefit trust activity is partially taxable while the pension trust activity is non-taxable. The EROA is based on current asset allocations as described in Note 14 of the Notes to Consolidated Financial Statements. A change in the asset allocation strategy could significantly impact the EROA and related costs.

Exelon calculates the expected return on pension and other postretirement benefit plan assets by multiplying the EROA by the market-related value (MRV) of plan assets at the beginning of the year, taking into consideration anticipated contributions and benefit payments that are to be made during the year. SFAS No. 87, "Employer's Accounting for Pensions" (SFAS No. 87) and SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other than Pensions" (SFAS No. 106) allow the MRV of plan assets to be 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. Exelon uses a calculated value when determining the MRV of the pension plan assets that adjusts for 20% of the difference between fair value and expected MRV of plan assets. This calculated value has the effect of stabilizing variability in assets to which Exelon applies the expected return. Exelon uses fair value when determining the MRV of the other postretirement benefit plan assets and the AmerGen pension plan assets.

The discount rate for determining the pension benefit obligations was 6.09%, 6.20%, and 5.90% at December 31, 2008, 2007, and 2006, respectively. The discount rate for determining the other postretirement benefit obligations was 6.09%, 6.20%, and 5.85% at December 31, 2008, 2007, and 2006, respectively. At December 31, 2008, 2007, and 2006, the discount rate was determined by developing a spot rate curve based on the yield to maturity of a universe of Aa graded 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.

The discount rate assumptions used to determine the obligation at year end will be used to determine the cost for the following year. Exelon will use a discount rate and EROA of 6.09% and 8.50%, respectively, for estimating its 2009 pension costs. Additionally, Exelon will use a discount rate and expected return on plan assets of 6.09% and 8.10%, respectively, for estimating its 2009 other postretirement benefit costs.

The following tables illustrate the effects of changing certain of the major actuarial assumptions discussed above (dollars in millions):

Change in Actuarial Assumption	Impact on Pension Liability at December 31, 2008	Impact on 2008 Pension Cost	Impact on Postretirement Benefit Liability at December 31, 2008	Impact on 2008 Postretirement Benefit Cost
Pension benefits				
Decrease discount rate by 0.5%	$641	$52	$212	$26
Decrease rate of EROA by 0.5%	—	48	—	8

Assumed health care cost trend rates also have a significant effect on the costs reported for Exelon's and AmerGen's postretirement benefit plans. A one-percentage point change in assumed health care cost trend rates would have had the following effects on the December 31, 2008 postretirement benefit obligation and estimated 2008 costs (dollars in millions):

Change in Actuarial Assumption	Impact on Other Postretirement Benefit Obligation at December 31, 2008	Impact on 2008 Total Service and Interest Cost Components
Increase assumed health care cost trend by 1%	$ 431	$ 49
Decrease assumed health care cost trend by 1%	(358)	(40)

Extending the year at which the ultimate health care trend rate of 5% is forecasted to be reached by 5 years would have had the following effects on the December 31, 2008 postretirement benefit obligation and estimated 2008 costs (dollars in millions):

Change in Actuarial Assumption	Impact on Other Postretirement Benefit Obligation at December 31, 2008	Impact on 2008 Total Service and Interest Cost Components
Extend the year at which the ultimate health care trend rate of 5% is forecasted to be reached by 5 years	$145	$19

The assumptions are reviewed annually and at any interim remeasurement of the plan obligations. As these assumptions change from period to period, recorded pension and postretirement benefit amounts and funding requirements could also change. As allowed by SFAS No. 87 and SFAS No. 106, 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.

For pension benefits, Exelon amortizes its unrecognized prior service costs, and certain of its actuarial gains and losses, as applicable, based on participants' average remaining service periods. For other postretirement benefits, Exelon amortizes its unrecognized prior service costs over participants' average remaining service period related to 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 defined pension plan participants was 12.8 years, 13.0 years and 13.5 years for the years ended December 31, 2008, 2007 and 2006, respectively. The average remaining service period of postretirement benefit plan participants related to eligibility age was 6.9 years, 6.9 years, and 7.3 years for the years ended December 31, 2008, 2007 and 2006, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 9.4 years, 9.7 years and 10.3 years for the years ended December 31, 2008, 2007 and 2006, respectively.

Regulatory Accounting

Exelon, ComEd and PECO account for their regulated electric and gas operations in accordance with SFAS No. 71, which requires Exelon, ComEd, and PECO to reflect the effects of rate regulation in their financial statements. Regulatory assets represent costs that have been deferred to future periods when it is probable that the regulator will allow for future recovery through rates charged to customers. Regulatory liabilities represent revenues collected from customers in excess of prescribed recovery that must be refunded to customers through an adjustment of billing rates. Use of SFAS No. 71 is applicable to utility operations that meet the following criteria: (1) third-party regulation of rates; (2) cost-based rates; and (3) a reasonable assumption that all costs will be recoverable from customers through rates. As of December 31, 2008, Exelon, ComEd and PECO have concluded that the operations of ComEd and PECO meet the criteria. If it is concluded in a future period that a separable portion of those operations no longer meets the criteria of SFAS No. 71, Exelon, ComEd and PECO are required to eliminate the financial statement effects of regulation for that part of those operations, which would include the elimination of any or all regulatory assets and liabilities that had been recorded in their Consolidated Balance Sheets and the recognition of a one-time extraordinary item in their Consolidated Statements of Operations. The impact of not meeting the criteria of SFAS No. 71 would be material to the financial statements of Exelon, ComEd and PECO. If ComEd no longer met the criteria of SFAS No. 71, the impact on ComEd's capital structure could lead to an additional impairment of ComEd's goodwill, which could be significant and at least partially offset the extraordinary gain which would be recorded in the event ComEd reversed its net regulatory liability position. A write-off of regulatory assets and liabilities could limit the ability of ComEd and PECO to pay dividends under Federal and state law and cause significant volatility in future results of operations. See Notes 3, 7 and 19 of the Notes to Consolidated Financial Statements for additional information regarding regulatory issues, ComEd's goodwill and the significant regulatory assets and liabilities of Exelon, ComEd and PECO, respectively.

For each regulatory jurisdiction in which they conduct business, Exelon, ComEd and PECO continually assess whether the regulatory assets and liabilities continue to meet the criteria for probable future recovery or settlement. This assessment includes consideration of factors such as changes in applicable regulatory environments and recent rate orders, including for other regulated entities in the same jurisdiction. 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 SFAS No. 5, "Accounting for Contingencies" (SFAS No. 5), as to the amount of revenues billed under certain regulatory orders that will ultimately be refunded to customers upon finalization of the appropriate regulatory process. These assessments are based, to the extent possible, on past relevant experience with regulatory bodies, known circumstances specific to a particular matter, discussions held with the applicable regulatory body, and other factors. If the assessments and estimates made by Exelon, ComEd and PECO are ultimately different than actual events, 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 five-year financial swap contract with Generation that extends into 2013. PECO has entered into derivative natural gas contracts to hedge its long-term price risk in the natural gas market. In addition, Generation and PECO have entered into a long-term full requirements power purchase agreement under which PECO obtains all of its electric supply from Generation through 2010. 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 Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

The Registrants account for derivative financial instruments under SFAS No. 133, "Accounting for Derivatives and Hedging Activities, as Amended" (SFAS No. 133) and related interpretations. Determining whether or not a contract qualifies as a derivative under SFAS No. 133 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 SFAS No. 133 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 interpretive guidance related to SFAS No. 133, could result in previously excluded contracts being subject to the provisions of SFAS No. 133. Generation has determined that contracts to purchase uranium do not meet the definition of a derivative under SFAS No. 133 since they do not provide for net settlement and the uranium markets are not sufficiently liquid to conclude that forward contracts are readily convertible to cash. If the uranium markets do become sufficiently liquid in the future and Generation begins to account for uranium purchase 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 the provisions of SFAS No. 133, all derivatives are recognized on the balance sheet at their fair value unless they qualify for a normal purchases or 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 cost or value of the underlying exposure is deferred in accumulated other comprehensive income (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.

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 or normal sales are recognized when the underlying physical transaction is completed. Normal purchases and 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. While these contracts are considered derivative financial instruments under SFAS No. 133, the transactions have been designated as normal purchases or 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, and all of PECO's natural gas supply agreements that are derivatives, qualify for the normal purchases and normal sales exception to SFAS No. 133. 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 or offset by a regulatory asset or liability at ComEd and PECO. Triggering events that could result in a contract's loss of the normal purchase or normal sale designation, because it is no longer probable that the contract will result in physical delivery, include changes in counterparty credit and book-outs (financial settlements).

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 that the forecasted future transactions are probable. When a contract does not meet the effective or probable criteria of SFAS No. 133, 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 SFAS No. 157, 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 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 Generation believes provide the most liquid market for the commodity. Generation reviews and corroborates the price quotations to ensure the prices are observable which includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. Generation's non-exchange-based derivatives are predominately at liquid trading points. 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. 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. In instances where observable data is unavailable, Generation considers 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. Generation considers 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. The impacts of credit and nonperformance risk were not material to the financial statements.

Interest-Rate Derivative Instruments. 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. 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, 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 Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

Taxation

Beginning January 1, 2007, the Registrants began accounting 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 attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being ultimately realized upon ultimate settlement in accordance with FASB Accounting Standards Board Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109" (FIN 48). If it is not more likely than not that the benefit 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. Prior to January 1, 2007, the Registrants estimated their uncertain income tax obligations in accordance with SFAS No. 109, "Accounting for Income Taxes" (SFAS No. 109), SFAS No. 5, and Statement of Financial Accounting Concepts No. 6, "Elements of Financial Statements-a replacement of FASB Concepts Statement No. 3 (incorporating an amendment of FASB Concepts Statement No. 2)" (CON 6). The Registrants recognize accrued interest related to unrecognized tax benefits in interest expense or interest income in other income and deductions on their Consolidated Statements of Operations. The Registrants also have non-income tax obligations related to real estate, sales and use and employment-related taxes and ongoing appeals related to these tax matters that are outside the scope of FIN 48 and accounted for under SFAS No. 5 and CON 6.

Accounting for tax positions requires judgments, including estimating reserves for potential uncertainties. 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 do not record valuation allowances for deferred tax assets that the Registrants believe will be realized in future periods. While the Registrants believe the resulting tax balances as of December 31, 2008 and 2007 are appropriately accounted for in accordance with FIN 48, SFAS No. 5, SFAS No. 109 and CON 6 as applicable, the ultimate outcome of such matters could result in favorable or unfavorable adjustments to their consolidated financial statements and such adjustments could be material. See Note 11 of the 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 that occurs 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 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. 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.

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. Projecting 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.

Allowance for Uncollectible Accounts

The allowance for uncollectible accounts reflects the Registrants' best estimates of probable losses on the accounts receivable balances. The allowance is based on known troubled accounts, historical experience and other currently available evidence. For ComEd and PECO, customer 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. Customer accounts are written off consistent with approved regulatory guidelines. ComEd and PECO are each currently obligated to provide service to all electric customers within their respective franchised territories and are prohibited from terminating electric service to certain residential customers due to nonpayment during certain months of the year. ComEd's and PECO's provisions for uncollectible accounts will continue to be affected by changes in prices and economic conditions as well as changes in ICC and PAPUC regulations, respectively. Under Pennsylvania's Competition Act, licensed entities, including competitive electric generation suppliers, may act as agents to provide a single bill and provide associated billing and collection services to retail customers located in PECO's retail electric service territory. Currently, there are no third parties providing billing of PECO's charges to customers or advanced metering; however, if this occurs, PECO would need to make adjustments to the provision for uncollectible accounts for the ability of the third parties to collect such receivables from the customers.

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. Unbilled revenue is estimated each month based on daily customer usage measured by generation or gas throughput volume, estimated customer usage by class, estimated 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 estimated 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.

Results of Operations (Dollars in millions, except for per share data, unless otherwise noted)

Results of Operations—Exelon

	2008	2007	Favorable (unfavorable) 2008 vs. 2007 variance	2006	Favorable (unfavorable) 2007 vs. 2006 variance
Operating revenues	$18,859	$18,916	$ (57)	$15,655	$ 3,261
Operating expenses					
Purchased power and fuel	6,582	7,642	1,060	5,232	(2,410)
Operating and maintenance	4,566	4,289	(277)	3,868	(421)
Impairment of goodwill	—	—	—	776	776
Depreciation and amortization	1,634	1,520	(114)	1,487	(33)
Taxes other than income	778	797	19	771	(26)
Total operating expenses	13,560	14,248	688	12,134	(2,114)
Operating income	5,299	4,668	631	3,521	1,147
Other income and deductions					
Interest expense	(699)	(647)	(52)	(616)	(31)
Interest expense to affiliates, net	(133)	(203)	70	(264)	61
Equity in losses of unconsolidated affiliates	(26)	(106)	80	(111)	5
Other, net	(407)	460	(867)	266	194
Total other income and deductions	(1,265)	(496)	(769)	(725)	229
Income from continuing operations before income taxes	4,034	4,172	(138)	2,796	1,376
Income taxes	1,317	1,446	129	1,206	(240)
Income from continuing operations	2,717	2,726	(9)	1,590	1,136
Income from discontinued operations, net of income taxes	20	10	10	2	8
Net income	$ 2,737	$ 2,736	$ 1	$ 1,592	$ 1,144
Diluted earnings per share	$ 4.13	$ 4.05	$ 0.08	$ 2.35	$ 1.70

Net Income.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. Exelon's net income for 2008 was consistent compared to 2007. Increases were primarily due to higher average realized margins at Generation, reflecting higher realized prices on market sales; increased revenue from certain long options in Generation's proprietary trading portfolio; net mark-to-market gains on economic hedging activities; the impact of the Illinois Settlement reached in 2007; increased transmission and delivery service revenue at ComEd in 2008 resulting from the 2007 transmission and distribution rate cases; the impact of a 2007 loss associated with Generation's tolling agreement with Georgia Power related to the contract with Tenaska; the impact of a decreased charitable contribution to the Exelon Foundation; and gains related to the settlement of claims related to uranium supply agreements. These increases were offset by unrealized and realized losses associated with Generation's nuclear decommissioning trust funds related to its Unregulated Units; increased nuclear fuel costs; decreased nuclear output at Generation reflecting increased scheduled refueling

outage days in 2008; increased operating and maintenance expense related to the higher number of planned nuclear refueling outages; unfavorable weather conditions in the ComEd and PECO service territories; increased allowance for uncollectible accounts expense at PECO and ComEd as well as the establishment of a reserve related to Generation's accounts receivable from Lehman; labor-related inflation; increased scheduled CTC amortization expense at PECO; impact of a gain realized in 2007 on nuclear decommissioning trust fund investments related to the Unregulated Units primarily associated with changes in Generation's investment strategy; realized nuclear decommissioning trust fund losses related to a tax planning strategy; the impact of the favorable 2007 PJM Interconnection, LLC billing settlement with PPL Electric; the impact of the termination of Generation's PPA with State Line in 2007; and income associated with investments in synthetic fuel-producing facilities in 2007.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. Exelon's net income for 2007 increased due to the impact of a $776 million impairment charge in 2006 associated with ComEd's goodwill; higher average margins on Generation's wholesale market sales primarily due to the end of the below-market price PPA with ComEd at the end of 2006; increased nuclear output at Generation reflecting fewer outage days; increased transmission revenues at ComEd; increased rates for delivery services at ComEd; favorable weather conditions in the ComEd and PECO service territories; increased delivery volume, excluding the effects of weather, at ComEd and PECO; income associated with the termination of Generation's PPA with State Line; a favorable PJM billing settlement with PPL; decreased nuclear refueling outage costs; the impact of incremental storm costs in 2006 associated with storm damage in the PECO service territory; gains realized on decommissioning trust fund investments related to changes in the investment strategy; favorable income tax benefit associated with Exelon's method of capitalizing overhead costs; increased earnings associated with synthetic fuel-producing facilities; the reduction in the reserve related to the successful PURTA tax settlement at PECO; and the impact of a charge in 2006 associated with the termination of the proposed merger with PSEG. These increases were partially offset by decreased energy margins at ComEd due to the end of the regulatory transition period; unrealized mark-to-market losses on contracts not yet settled; the impact of the Illinois Settlement; a loss associated with Generation's tolling agreement with Georgia Power related to the contract with Tenaska; a greater reduction in 2006 compared to 2007 in Generation's nuclear decommissioning obligation related to the Unregulated Units; the impact of inflationary cost pressures; increased pension and non-pension postretirement benefits expense; increased uncollectible accounts expense at ComEd and PECO; incremental storm costs associated with storm damage in the ComEd service territory; a charitable contribution of $50 million to the Exelon Foundation; increased amortization expense related to scheduled CTC amortization at PECO; costs associated with the possible construction of a new nuclear plant in Texas; benefits in 2006 of approximately $288 million to recover certain costs by the ICC rate orders; and the impact of favorable tax settlements at PECO in 2006.

Operating Revenues.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. Operating revenues decreased due to lower nuclear output due to more planned refueling outage days in 2008; unfavorable weather conditions in the ComEd and PECO service territories; the impact of the Illinois Settlement; the reduction in PECO's distribution rates made to refund the PURTA tax settlement to customers (completely offset by the amortization of the regulatory liability reflected in taxes other than income); and the impact of the termination of Generation's PPA with State Line in 2007. These decreases were partially offset by higher realized prices on market sales at Generation; increased transmission and delivery service revenue at ComEd resulting from the 2007 transmission and distribution rate cases; increased delivery volumes, excluding the effects of weather, at PECO; and increased revenue from certain long options in Generation's proprietary trading portfolio. See additional analysis and discussion of operating revenues by segment below.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. Operating revenues increased due to an increase in wholesale and retail electric sales at Generation resulting from higher volumes of generation sold to the market at higher prices as a result of the expiration of the ComEd PPA at the end of 2006; income associated with the termination of Generation's PPA with State Line; the impact of rate changes and mix at ComEd due to the end of the rate freeze and the implementation of market-based rates for electricity; increased transmission revenues at ComEd resulting from the 2007 transmission rate case; increased rates for delivery services at ComEd; favorable weather conditions in the ComEd and PECO service territories; higher delivery volumes, excluding the effects of weather, at ComEd and PECO; and authorized electric generation rate increases under the 1998 restructuring agreement at PECO. These increases were partially offset by more non-residential customers at ComEd electing to purchase electricity from a competitive electric generation supplier; costs associated with ComEd's settlement agreement with the City of Chicago; and the expiration of certain wholesale contracts at ComEd. See additional analysis and discussion of operating revenues by segment below.

Purchased Power and Fuel Expense.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. Purchased power and fuel expense decreased due to net mark-to-market gains on economic hedging activities; favorable settlements reached in 2008 related to uranium supply

agreements; unfavorable weather conditions in the ComEd and PECO service territories; and the impact of a 2007 loss associated with Generation's tolling agreement with Georgia Power related to a contract with Tenaska. These decreases were partially offset by increased nuclear fuel costs at Generation; increased transmission expense at PECO; and the impact of the favorable PJM billing dispute settlement with PPL in 2007. See additional analysis and discussion of purchased power and fuel expense by segment below.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. Purchased power and fuel expense increased due to higher market energy prices; unrealized mark-to-market losses on contracts not yet settled; a loss associated with Generation's tolling agreement with Georgia Power related to a contract with Tenaska; higher prices for electricity purchased by ComEd; and favorable weather conditions in the ComEd and PECO service territories. Purchased power represented 20% of Generation's total supply for 2007 and 2006. The increases in purchased power and fuel expense were partially offset by a favorable PJM billing settlement with PPL in 2007; more non-residential customers at ComEd electing to purchase electricity from a competitive electric generation supplier; and the expiration of certain wholesale contracts at ComEd. In 2007, as a result of the ICC-approved reverse-auction process, ComEd began procuring electricity, including ancillary services, under its supplier forward contracts from PJM-administered wholesale electricity markets. See additional analysis and discussion of purchased power and fuel expense by segment below.

Operating and Maintenance Expense.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. Operating and maintenance expense increased primarily due to increased allowance for uncollectible accounts expense at PECO and ComEd as well as the establishment of a reserve related to Generation's accounts receivable from Lehman; discrete disallowances, net of allowed regulatory assets, mandated by the September 2008 ICC order in ComEd's 2007 delivery service rate case; labor-related inflation; increased expenses related to a higher number of planned nuclear refueling outages, including planned nuclear refueling outage costs at Salem; and decreased nuclear insurance credits accrued by Generation in 2008. These increases are partially offset by a decrease in costs associated with the evaluation and development of a new nuclear generating facility in Texas; decreased charitable contributions to the Exelon Foundation; and decreased stock-based compensation costs. See further discussion of operating and maintenance expenses by segment below.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. Operating and maintenance expense increased primarily due to increased pension and non-pension postretirement benefits expense; the impact of inflationary cost pressures; a greater reduction in 2006 compared to 2007 in Generation's nuclear decommissioning obligation related to the Unregulated Units; increased uncollectible accounts expense at ComEd and PECO; incremental storm costs associated with storm damage in the ComEd service territory; a charitable contribution of $50 million to the Exelon Foundation; new nuclear site development costs for the evaluation and development of a new nuclear generating facility in Texas; increased tax consulting fees; and the impact of benefits of $201 million recorded at ComEd in 2006 as a result of the 2006 ICC rate orders. These increases were partially offset by a decrease in nuclear refueling outage costs associated with the fewer planned refueling outage days during 2007 compared to 2006; the impact of incremental storm costs in 2006 associated with storm damage in the PECO service territory; and the impact of a charge recorded in 2006 of approximately $55 million for the write-off of capitalized costs associated with the now terminated proposed merger with PSEG. See additional discussion of operating and maintenance expenses by segment below.

Depreciation and Amortization Expense.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. Depreciation and amortization expense increased primarily due to increased scheduled CTC amortization expense at PECO and higher plant balances due to additional plant placed in service across Exelon.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. Depreciation and amortization expense increased primarily due to scheduled CTC amortization at PECO and additional plant placed in service across Exelon. These increases were partially offset by lower amortization related to investments in synthetic fuel-producing facilities.

Taxes Other Than Income.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. Taxes other than income decreased primarily due to an Illinois distribution tax refund received in 2008 and the amortization of the regulatory liability recorded in connection with the 2007 PURTA settlement, which began in January 2008 and is offset by lower revenues due to a reduction in the distribution rates to refund the PURTA taxes to customers. These factors are partially offset by the impact of increased property taxes and payroll taxes.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. Taxes other than income increased primarily due to an increase in utility taxes resulting from higher utility revenues at PECO and the impact of favorable tax settlements at PECO in 2006. These increases were partially offset by a reduction of a reserve related to the successful PURTA tax settlement at PECO.

Other Income and Deductions.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. The change in other income and deductions primarily reflects unrealized and realized losses on Generation's nuclear decommissioning trust fund investments of its Unregulated Units; the impact of 2007 gain from sale of Generation's investment in TEG and TEP; and the income associated with investments in synthetic fuel-producing facilities that ceased operations at the end of 2007.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. The change in other income and deductions reflects interest income related to the favorable PJM billing settlement with PPL; a gain related to the sale of investments by Generation; income and gains associated with the nuclear decommissioning trust funds of the Unregulated Units, net of other than temporary impairments, primarily associated with changes in Generation's investment strategy; benefits of $87 million recorded by ComEd in 2006 as a result of the 2006 ICC rate order; and earnings associated with investments in synthetic fuel-producing facilities.

Effective Income Tax Rate.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. The effective income tax rate was 32.6% for 2008 compared to 34.7% for 2007. The 2008 rate decreased, as compared with 2007, primarily due to the impact of higher marginal tax rates applicable to realized and unrealized losses in the nuclear decommissioning trust funds recorded at Generation, partially offset by the expiration of synthetic fuel tax credits under Internal Revenue Code Section 45K on December 31, 2007.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. The effective income tax rate was 34.7% for 2007 compared to 43.1% for 2006. The 2007 rate decreased, as compared with 2006, primarily due to ComEd's non-deductible goodwill impairment charge in 2006 which increased the rate by 9.7% and a decrease of state tax expense in 2007 of 1.5% due to a tax restructuring to allow utilization of separate company losses for state income tax purposes, partially offset by a reduction in synthetic fuel credits of 1.7% in 2007 caused by an increase in the phase-out due to higher oil prices, and other changes amounting to 1.1%. See Note 11 of the Notes to Consolidated Financial Statements for additional information of the components of the effective income tax rates and discussion on the investments in synthetic fuel-producing facilities.

Discontinued Operations.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. Income from discontinued operations related to expiration of tax indemnifications in connection to a prior investment in Sithe Energies, Inc. (Sithe).

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe Energies, Inc (Sithe). In addition, Exelon has sold or wound down substantially all components of Exelon Enterprises Company, LLC (Enterprises). Accordingly, the results of operations and any gain or loss on the sale of these entities have been presented as discontinued operations within Exelon's (for Sithe and Enterprises) and Generation's (for Sithe) Consolidated Statements of Operations. See Note 2 of the Notes to Consolidated Financial Statements for additional information regarding the presentation of Sithe and certain Enterprises businesses as discontinued operations.

Results of Operations by Business Segment

The comparisons of 2008, 2007, and 2006 operating results and other statistical information set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Net Income (Loss) from Continuing Operations by Business Segment

	2008	2007	Favorable (unfavorable) 2008 vs. 2007 variance	2006	Favorable (unfavorable) 2007 vs. 2006 variance
Generation	$2,258	$2,025	$ 233	$1,403	$ 622
ComEd	201	165	36	(112)	277
PECO	325	507	(182)	441	66
Other [(a)]	(67)	29	(96)	(142)	171
Total	$2,717	$2,726	$ (9)	$1,590	$1,136

(a) Other primarily includes corporate operations, BSC, investments in synthetic fuel-producing facilities and intersegment eliminations.

Net Income (Loss) by Business Segment

	2008	2007	Favorable (unfavorable) 2008 vs. 2007 variance	2006	Favorable (unfavorable) 2007 vs. 2006 variance
Generation	$2,278	$2,029	$ 249	$1,407	$ 622
ComEd	201	165	36	(112)	277
PECO	325	507	(182)	441	66
Other [(a)]	(67)	35	(102)	(144)	179
Total	$2,737	$2,736	$ 1	$1,592	$1,144

(a) Other primarily includes corporate operations, BSC, investments in synthetic fuel-producing facilities and intersegment eliminations.

Results of Operations—Generation

	2008	2007	Favorable (Unfavorable) Variance 2008 vs. 2007	2006	Favorable (Unfavorable) Variance 2007 vs. 2006
Operating revenues	$10,754	$10,749	$ 5	$9,143	$1,606
Operating expenses					
Purchased power and fuel	3,572	4,451	879	3,978	(473)
Operating and maintenance	2,717	2,454	(263)	2,305	(149)
Depreciation and amortization	274	267	(7)	279	12
Taxes other than income	197	185	(12)	185	—
Total operating expenses	6,760	7,357	597	6,747	(610)
Operating income	3,994	3,392	602	2,396	996
Other income and deductions					
Interest expense	(136)	(161)	25	(159)	(2)
Equity in earnings (losses) of investments	(1)	1	(2)	(9)	10
Other, net	(469)	155	(624)	41	114
Total other income and deductions	(606)	(5)	(601)	(127)	122
Income from continuing operations before income taxes	3,388	3,387	1	2,269	1,118
Income taxes	1,130	1,362	232	866	(496)
Income from continuing operations	2,258	2,025	233	1,403	622
Income (loss) from discontinued operations, net of income taxes	20	4	16	4	—
Net income	$ 2,278	$ 2,029	$ 249	$1,407	$ 622

Net Income.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. Generation's net income increased primarily due to higher operating revenues, net of purchased power and fuel expense, partially offset by higher operating and maintenance expenses and unrealized and realized losses in 2008 and realized gains in 2007 related to nuclear decommissioning trust funds associated with the Unregulated Units. Higher net operating revenues, net of purchased power and fuel expense, reflected higher average realized margins, higher net mark-to-market gains on economic hedging activities, lower costs incurred in conjunction with the Illinois Settlement, a 2007 loss associated with the tolling agreement with Georgia Power related to the contract with Tenaska, increased revenue from certain long options in the proprietary trading portfolio and gains related to the settlement of uranium supply agreements in 2008, partially offset by increased nuclear fuel costs, lower nuclear output reflecting a higher number of scheduled refueling and non-refueling outage days, the gain on the termination of the State Line PPA in 2007, a favorable PJM billing settlement with PPL in 2007 and impairments of stored oil and gas inventory in 2008. Higher operating and maintenance expenses included increased wages, salaries and benefits (excluding stock-based compensation), nuclear refueling outage costs associated with a higher number of planned refueling outages, higher costs associated with nuclear decommissioning-related activities and the establishment of a reserve related to counterparty exposure to Lehman, partially offset by decreases in contractor expenses, stock-based compensation and costs associated with the possible construction of a nuclear power plant in Texas. Additional offsets to increased net income in 2008 included decommissioning trust fund activity associated with the Unregulated Units which reflected unrealized losses in 2008, realized losses related to a tax planning strategy in 2008 and the impact of realized gains in 2007 associated with changes in Generation's investment strategy.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. Generation's net income increased primarily due to higher revenue, net of purchased power and fuel expense, more than offsetting inflationary and other cost pressures, a greater reduction in 2006 compared to 2007 in the nuclear decommissioning obligation related to the Unregulated Units and costs associated with the new nuclear plant COL application. Generation's revenue, net of purchased power and fuel expense, increased due to higher average margins primarily due to the end of the below-market price PPA with ComEd at the end of 2006, the contractual increase in the prices associated with Generation's PPA with PECO, the termination of the State Line PPA and a favorable PJM billing settlement with PPL in 2007, partially offset by amounts incurred in conjunction with the Illinois Settlement, net mark-to-market losses on derivative activities and the execution of the Georgia Power PPA. In addition to these impacts, Generation's net income for 2007 included (all after tax) gains of $38 million related to the Unregulated Units associated with changes in Generation's investment strategy with the decommissioning trust fund investments, a gain on the sale of investments of $11 million and earnings of $4 million associated with the settlement of a tax matter related to Generation's previous investment in Sithe.

Operating Revenues. For 2008, 2007 and 2006 Generation's revenues were as follows:

			2008 vs. 2007			2007 vs. 2006	
Revenue	**2008**	**2007**	**Variance**	**% Change**	**2006**	**Variance**	**% Change**
Electric sales to affiliates	$ 3,561	$ 3,537	$ 24	0.7%	$4,674	$(1,137)	(24.3)%
Wholesale and retail electric sales [a]	6,720	6,834	(114)	(1.7)%	3,640	3,194	87.7%
Total electric sales revenue	10,281	10,371	(90)	(0.9)%	8,314	2,057	24.7%
Retail gas sales	497	449	48	10.7%	540	(91)	(16.9)%
Trading portfolio	106	43	63	146.5%	14	29	207.1%
Other operating revenue [b]	(130)	(114)	(16)	14.0%	275	(389)	(141.4)%
Total operating revenue	$10,754	$10,749	$ 5	0.0%	$9,143	$ 1,606	17.6%

(a) For 2008, $2 million of pre-tax reduction in revenue from settlements related to the ComEd swap and $29 million of pre-tax revenue from sales to ComEd under the RFP have been excluded from ComEd and included in Marketing and Retail sales.

(b) Includes amounts incurred for the Illinois Settlement for 2008 and 2007, and revenues relating to fossil fuel sales and decommissioning revenue from PECO during 2008, 2007 and 2006.

			2008 vs. 2007			2007 vs. 2006	
Sales (in gigawatt hours (GWhs) [a])	**2008**	**2007**	**Variance**	**% Change**	**2006**	**Variance**	**% Change**
Electric sales to affiliates	64,166	64,406	(240)	(0.4)%	119,354	(54,948)	(46.0)%
Wholesale and retail electric sales	112,008	125,244	(13,236)	(10.6)%	71,326	53,918	75.6%
Total electric sales	176,174	189,650	(13,476)	(7.1)%	190,680	(1,030)	(0.5)%

(a) 486 GWh during 2008, resulting from sales to ComEd under the RFP starting in September 2008, have been excluded from ComEd and included in Market and Retail sales.

Trading volumes of 8,891 GWhs, 20,323 GWhs and 31,692 GWhs for 2008, 2007 and 2006, respectively, are not included in the table above.

Electric sales to affiliates. The changes in Generation's electric sales to affiliates for 2008 compared to 2007 and 2007 compared to 2006 consisted of the following:

	Variance 2008 vs. 2007			Variance 2007 vs. 2006		
Electrical sales to affiliates	**Price**	**Volume**	**Total Increase (Decrease)**	**Price**	**Volume**	**Total Increase (Decrease)**
ComEd	$ (9)	$ 9	$—	$650	$(2,035)	$(1,385)
PECO	43	(19)	24	169	79	248
Total	$34	$(10)	$ 24	$819	$(1,956)	$(1,137)

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. In the ComEd territories the volume increase was primarily the result of an acquisition by Generation from an unrelated third party of the unrelated third party's supply obligations under the ComEd auction effective January 1, 2008. The price decrease in the ComEd territories was largely due to final reconciliation activity recorded in 2007 associated with the full requirements ComEd PPA which ended on December 31, 2006. In the PECO territories, the price increase reflects a favorable change in the mix of average pricing related to PECO's PPA with Generation, in addition to the effects of the last scheduled rate increase under the PPA, which took effect in mid-January 2007. The volume decrease in the PECO territories was primarily due to unfavorable weather conditions.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. In the ComEd territories, decreased volumes were the result of the expiration of Generation's PPA with ComEd effective December 31, 2006. The decrease was partially offset by higher prices received by Generation following the expiration of the PPA, under which Generation was receiving below-market rates. With the expiration of the PPA, Generation is now receiving higher prices from ComEd under the forward supply contracts. In the PECO territories, higher prices were the result of a scheduled electric generation rate increase that took effect January 1, 2007.

Wholesale and retail electric sales. The increase in Generation's wholesale and retail electric sales for 2008 compared to 2007 and 2007 compared to 2006 consisted of the following:

	Increase (Decrease)	
	2008 vs. 2007	**2007 vs. 2006**
Volume	$(720)	$2,782
Price	606	412
Increase (decrease) in wholesale and retail electric sales	$(114)	$3,194

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. The decrease in volumes is reflective of an increased use of financial instruments versus physical contracts in addition to lower volumes of generation sold to the market, including the termination of the Stateline PPA in October 2007. The increase in price was primarily the result of an overall increase in market prices and includes a $29 million increase in revenue related to the ComEd RFP.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. The increase in wholesale and retail electric sales was primarily the result of higher volumes of generation sold to the market as a result of the expiration of the ComEd PPA at the end of 2006.

Retail gas sales. Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. Retail gas sales increased $48 million of which $74 million was due to higher realized prices offset by a $26 million decrease due to lower volumes as a result of decreased demand.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. Retail gas sales decreased $91 million of which $53 million of the decrease was due to lower volumes as a result of lower demand and $38 million was due to lower realized prices.

Trading Portfolio. Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. The trading portfolio increased $63 million which was due primarily to earnings from certain long options in the proprietary trading portfolio.

Other revenue. Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. The decrease in other revenues was primarily due to the $223 million of income in 2007 associated with the termination of Generation's PPA with State Line Energy, L.L.C. (State Line), partially offset by $187 million in reduced customer credits issued to ComEd and Ameren and $14 million Salem oil spill settlement received in December 2008. See Note 18 of the Notes to Consolidated Financial Statements for additional information regarding the oil spill settlement.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. The decrease in other revenues was primarily due to a $408 million decrease for amounts recorded related to the Illinois Settlement, a decrease of $86 million due to the cessation of a tolling agreement and a $66 million decrease related to the termination of decommissioning collections from ComEd in accordance with the terms and conditions of the ICC order which only permitted such collections through December 31, 2006, partially offset by income of $223 million related to the termination of the State Line PPA. Additionally, a $40 million decrease in other revenues was attributable to the sale of Termoeléctrica del Golfo (TEG) and Termoeléctrica Peñoles (TEP) on February 9, 2007 and the resulting absence of revenue thereafter.

Purchased Power and Fuel Expense. Generation's supply sources are summarized below:

			2008 vs. 2007			2007 vs. 2006	
Supply Source (in GWhs)	**2008**	**2007**	**Variance**	**% Change**	**2006**	**Variance**	**% Change**
Nuclear generation [(a)]	139,342	140,359	(1,017)	(0.7)%	139,610	749	0.5%
Purchases	26,263	38,021	(11,758)	(30.9)%	38,297	(276)	(0.7)%
Fossil and hydroelectric generation	10,569	11,270	(701)	(6.2)%	12,773	(1,503)	(11.8)%
Total supply	176,174	189,650	(13,476)	(7.1)%	190,680	(1,030)	(0.5)%

(a) Supply source in GWhs at ownership.

The following table presents changes in Generation's purchased power and fuel expense for 2008 compared to 2007 and 2007 compared to 2006. Generation considers the aggregation of purchased power and fuel expense as a useful measure to analyze the profitability of electric operations between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, the aggregation of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information Generation provides elsewhere in this Financial Information supplement.

	Variance 2008 vs. 2007			Variance 2007 vs. 2006		
	Price	**Volume**	**Total Increase (Decrease)**	**Price**	**Volume**	**Total Increase (Decrease)**
Purchased power costs and tolling agreement costs [(a)]	$ 767	$(825)	$ (58)	$ 236	$ (47)	$189
Generation costs [(b)]	(89)	(12)	(101)	2	(5)	(3)
Fuel resale costs	99	(25)	74	(56)	(38)	(94)
Mark-to-market	n.m.	n.m.	(623)	n.m.	n.m.	275
(Decrease) increase in purchased power and fuel expense			$(708)			$367

(a) Variance for both periods presented excludes the net impact of $119 million loss recorded in 2007 associated with Generation's tolling agreement with Georgia Power related to the contract with Tenaska. See Note 18 of the Notes to the Consolidated Financial Statements for additional information.

(b) Variance for 2008 as compared to 2007 excludes gains of approximately $53 million related to non-performance claims for uranium supply agreements recorded in 2008. Variance for 2007 as compared to 2006 excludes the net impact of a $13 million one-time settlement with the Department of Energy recorded in 2006 for uranium enrichment services. See Note 18 of the Notes of the Consolidated Financial Statements for additional information.

n.m. Not meaningful.

Purchased Power Costs and Tolling Agreement Costs.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. Purchased power costs include all costs associated with the procurement of electricity including capacity, energy and fuel costs associated with tolling agreements. Generation had lower purchased power volumes primarily due to market conditions that resulted in decreased purchases from contracted units as well as decreased volumes due to the termination of the State Line PPA in October 2007. The decrease in volumes is also reflective of an increased use of financial instruments versus physical contracts. Generation realized overall higher prices for purchased power as a result of an overall increase in market prices. Further, Generation's purchased power costs increased $28 million due to the favorable PJM billing dispute settlement with PPL in the first quarter of 2007.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. Generation had lower purchased power volumes primarily due to lower volumes needed to supply ComEd as a result of the expiration of the PPA at December 31, 2006. Generation incurred overall higher prices for purchased power, partially offset by a decrease of $28 million due to the favorable PJM billing dispute settlement with PPL in 2007. See Note 12 of the Notes to Consolidated Financial Statements.

Generation Costs. Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. Generation cost includes fuel cost for internally generated energy. Generation experienced overall lower generation costs for the year ended December 31, 2008, as compared to the same period in 2007 due to decreased realized prices and lower volumes. Additionally, Generation has recorded gains of approximately $53 million related to non-performance claims for uranium supply agreements. See Note 18 of the Notes to the Consolidated Financial Statements for further information. Partially offsetting the overall decrease in realized prices and gains associated with uranium supply agreement costs were increased costs for uranium and fossil fuel inventory impairments of $21 million during the year ended December 31, 2008.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. Generation costs were relatively flat. The decrease in volume of $5 million was primarily due to lower fossil and hydroelectric generation, partially offset by higher nuclear generation.

Fuel Resale Costs. Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. Fuel resale cost includes retail gas purchases and wholesale fossil fuel expenses. The changes in Generation’s fuel resale costs for 2008 as compared to 2007 consisted of overall higher prices resulting in an increase of $87 million, in addition to a retail gas inventory impairment of $12 million during the year 2008. Additionally, lower volumes caused by lower demand resulted in a decrease of $25 million.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. The changes in Generation’s fuel resale costs consisted of overall lower prices resulting in a decrease of $56 million. Additionally, a decrease of $38 million was the result of lower volumes caused by lower demand.

Mark-to-market. Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on power hedging activities were $414 million in 2008 compared to losses of $253 million in 2007. Mark-to-market gains on fuel hedging activities were $38 million in 2008 compared to gains of $81 million in 2007. See Notes 8 and 9 of the Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives under SFAS No. 157.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. Mark-to-market losses on power derivative activities were $253 million in 2007 compared to gains of $180 million in 2006. Mark-to-market gains on fuel derivative activities were $81 million in 2007 compared to losses of $77 million in 2006.

The following table presents average electric revenues, supply costs and margins per megawatt hours (MWh) of electricity sold during 2008 as compared 2007 and 2007 compared to 2006. As set forth in the table, average electric margins are defined as average electric revenues less average electric supply costs. Generation considers average electric margins useful measures to analyze the change in profitability of electric operations between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these margins are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information Generation provides elsewhere in this Financial Information supplement.

($/MWh)	2008	2007	2008 vs. 2007 % Change	2006	2007 vs. 2006 % Change
Average electric revenue					
Electric sales to affiliates [a]	$55.50	$54.90	1.1%	$39.16	40.2%
Wholesale and retail electric sales [a]	59.99	54.59	9.9%	51.03	7.0%
Total—excluding the trading portfolio	58.35	54.70	6.7%	43.60	25.5%
Average electric supply cost [b],[c]—excluding the proprietary trading portfolio	$19.87	$19.54	1.7%	$18.56	5.3%
Average margin—excluding the proprietary trading portfolio	$38.48	$35.16	9.4%	$25.04	40.4%

(a) For year 2008, $2 million of a pre-tax reduction in revenue from settlements related to the ComEd swap and $29M of pre-tax increase in revenue from the ComEd RFP have been excluded from Electric sales to affiliates and included in Wholesale and retail electric sales.

(b) Average supply cost includes purchased power and fuel costs associated with electric sales excluding the impact of mark-to-market hedging activities. Average electric supply cost does not include fuel costs associated with retail gas sales and other sales for all periods presented.

(c) For year 2007, excludes the net impact of the $119 million loss related to the execution of the Georgia Power PPA and costs related to the termination of the State Line PPA during 2007.

The following table presents nuclear fleet operating data for 2008, as compared to 2007 and 2006, 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 (1) 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.

	2008	2007	2006
Nuclear fleet capacity factor [a]	93.9%	94.5%	93.9%
Nuclear fleet production cost per MWh [a],[b]	$15.87	$14.46	$13.85

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC.

(b) For 2008, excludes the $53 million reduction in fuel expense related to uranium supply agreement non-performance settlements. See note 18 of the Notes to the Consolidated Financial Statements for further information.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. The nuclear fleet capacity factor decreased primarily due to a higher number of scheduled refueling outage days. For 2008 and 2007, refueling outage days totaled 241 and 195, respectively, while non-refueling outage days totaled 59 in both years. The lower number of net MWh's generated, the impact of inflation on labor and contracting costs and higher nuclear fuel costs plus the refueling outage costs associated with the higher number of refueling outage days resulted in a higher production cost per MWh during 2008 as compared 2007.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. The nuclear fleet capacity factor increased primarily due to fewer outage days. For 2007 and 2006, refueling outage days totaled 195 and 237, respectively, and non-refueling outage days totaled 59 and 71, respectively. The higher number of net MWh's generated and lower costs due to fewer planned refueling outage days were offset by higher costs for labor, nuclear fuel, NRC reactor fees, security costs and material condition work, resulting in an increase in the production cost per MWh for 2007 as compared to 2006.

Operating and Maintenance Expense.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. The increase in operating and maintenance expense for 2008 compared to 2007 consisted of the following:

	Increase (Decrease)
Wages, salaries and benefits	$112
Nuclear refueling outage costs, including the co-owned Salem plant	88
Nuclear decommissioning-related activities	57
Accounts receivable reserve	22
Nuclear insurance credits	15
Corporate allocations	13
Non-nuclear ARO adjustments	9
Contractor expenses	(26)
Stock-based compensation	(25)
New nuclear plant development costs	(22)
Other	20
Increase in operating and maintenance expense	$263

- The $112 million increase in wages, salaries and benefits reflects the impact of inflation and the costs for the Generation nuclear security personnel hired to replace the external organization that previously provided security services.
- The $88 million increase in nuclear refueling outage costs was primarily associated with the higher number of refueling outage days during 2008 as compared to 2007.
- The $57 million increase in nuclear decommissioning-related activities was associated with the $47 million increase in decommissioning-related activities related to the contractual elimination of income taxes associated with the decommissioning trust funds of the former ComEd and PECO nuclear generating units (Regulated Units) and the recognition of income of $19 million related to an ARO adjustment in 2008, compared to income of $29 million related to an ARO adjustment in 2007, representing reductions in the asset retirement obligation in excess of the asset retirement cost balances for the Unregulated Units.
- The $22 million increase in the accounts receivable reserve is the result of Generation's direct net exposure to Lehman. See Liquidity and Capital Resources—Economic Environment for additional information.
- The $15 million increase relates to a decrease in nuclear insurance credits accrued in 2008 as compared to 2007.
- The $13 million increase in corporate support service costs reflected an increase in a variety of BSC services allocated to Generation, including legal, human resources, financial, information technology and supply management services.
- The $9 million increase relates to non-nuclear asset retirement obligation adjustments in 2008 and 2007.
- The $26 million decrease in contractor costs was primarily related to lower contractor security costs due to Generation no longer using an external organization for security at its nuclear plants (Generation has hired its own personnel to provide security services). The decrease was partially offset by inflationary increases on non-outage contracting and services maintenance work at the nuclear plants and staff augmentation and maintenance work at the fossil and hydroelectric plants.
- The $25 million decrease in stock-based compensation was the result of a decrease in Exelon's stock price.
- The $22 million decrease in new nuclear plant development costs reflects a reduction in costs associated with the possible construction of a nuclear power plant in Texas.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. The increase in operating and maintenance expense for 2007 compared to 2006 consisted of the following:

	Increase (Decrease)
Wages, salaries and benefits	$ 85
New Nuclear plant development costs	49
Nuclear decommissioning-related activities	40
Contractor expenses	24
Corporate allocations	14
TEG and TEP related expenses	(39)
Nuclear refueling outage costs, including the co-owned Salem plant	(32)
Other	8
Increase in operating and maintenance expense	$149

- The $85 million increase in payroll, salaries and benefits reflected the impact of inflation as well as an increase in various direct fringe costs.
- The $49 million increase in new nuclear site development costs was due to costs incurred for the evaluation and development of a new nuclear generating facility in Texas, including fees and costs related to the COL, reservation payments for long-lead components of the project, and other site evaluation and development costs.
- The $40 million increase in nuclear decommissioning-related activities was primarily associated with the recognition of a credit of $29 million, compared to a credit of $149 million recognized in 2006, representing reductions in the asset retirement obligation in excess of the asset retirement cost balance for the Unregulated Units. Additionally, decommissioning-related activities decreased by $66 million resulting from the termination of revenue collections on December 31, 2006 from ComEd, which likewise no longer required an offset through operating and maintenance expense, and decreased by $14 million due to the offset of certain income-taxes associated with decommission-related activity.
- The $24 million increase in contractor expense was primarily related to staff augmentation and maintenance work at the nuclear, fossil and hydroelectric plants.
- The $14 million increase in corporate support service costs reflected an increase in a variety of BSC services allocated to Generation, including legal, human resources, financial, information technology and supply management services.
- The $39 million decrease in expenses related to TEG and TEP was due to the sale of the investment in 2007.
- The $32 million decrease in nuclear refueling outage costs was associated with the fewer planned refueling outage days during 2007 compared to 2006.

Depreciation and Amortization.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. For 2008 as compared to 2007, the increase in depreciation and amortization expense 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 reassessment of the useful lives of several fossil facilities. The impact of the reassessment of the useful lives did not and will not result in a material change to Generation's results of operations as compared to amounts recognized in periods prior to the change.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. For 2007 as compared to 2006, the decrease in depreciation and amortization expense was primarily due to the reassessment of the useful lives of several fossil facilities and the write-off of certain asset retirement costs in 2006.

Taxes Other Than Income.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. For 2008 as compared to 2007, the increase was primarily due to increased payroll taxes and property taxes, partially offset by a gross receipts tax adjustment in 2008.

Interest Expense.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. For 2008 as compared to 2007, the decrease in interest expense reflected lower interest on spent nuclear fuel obligations as a result of lower rates and an increase in interest expense related to a change in the estimate of the FIN 48 tax interest calculation in 2007, partially offset by increased interest from higher outstanding long-term debt balances as a result of the September 2007 bond issuance and higher outstanding commercial paper balances.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. For 2007 as compared to 2006, the increase in net interest expense was primarily attributable to an increase in interest expense related to a change in the estimate of the FIN 48 tax interest calculation and an increase in interest expense related to the bond issuance during the third quarter of 2007, partially offset by an interest payment accrued in 2006 for the settlement of a tax matter, a decline in the amount of commercial paper that was outstanding and an increase in average cash-on-hand balances during 2007 compared to 2006

Other, Net.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. For 2008 as compared to 2007, the decrease in other, net primarily reflects net unrealized losses in 2008 on the nuclear decommissioning trust funds of the Unregulated Units due to adverse financial market conditions, the contractual elimination of income taxes associated with the decommissioning trust funds of the Regulated Units, realized losses on the trust funds of the Unregulated Units due to the execution of a tax planning strategy in 2008, and realized gains in 2007 on nuclear decommissioning trust fund investments of the Unregulated Units associated with changes in Generation's investment strategy, partially offset by 2007 a gain on sale of TEG and TEP.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. For 2007 as compared to 2006, the increase in other, net reflects a gain on sale of investments recognized in 2007 and realized gains associated with nuclear decommissioning trust funds of the Unregulated Units, net of other than temporary impairments, primarily associated with changes in Generation's investment strategy.

The following table provides unrealized and realized gains (losses) on the decommissioning trust funds of the Unregulated Units recognized in other, net for 2008, 2007 and 2006:

	2008	2007	2006
Net unrealized gains (losses) on decommissioning trust funds—Unregulated Units	$(324)	$— [b]	$— [b]
Net realized gains (losses) on sale of decommissioning trust funds—Unregulated Units	$ (39)	$ 64	$ (1)
Other-than-temporary impairment of decommissioning trust funds—Unregulated Units [a]	n/a	$ (9)	$ (3)

(a) As a result of certain NRC restrictions, Exelon and Generation were unable to demonstrate the ability and intent to hold the nuclear decommissioning trust fund investments through a recovery period and, accordingly, recognized any unrealized holding losses immediately. After the adoption of the fair value option under SFAS No. 159 on January 1, 2008, other-than-temporary impairments are no longer recognized since all changes in fair value are recognized in the Statement of Operations beginning January 1, 2008.

(b) Unrealized gains (losses) were included in accumulated OCI on Exelon's and Generation's Consolidated Balance prior to the adoption of SFAS No. 159 on January 1, 2008.

See "Fair Value Option for Financial Assets and Liabilities" in Note 12 of the Notes to the Consolidated Financial Statements for further discussion on the adoption of SFAS No. 159 related to the nuclear decommissioning trust fund investments.

Effective Income Tax Rate

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. For 2008 as compared to 2007, the effective tax rate from continuing operations decreased to 33.4% for 2008 from 40.2% in 2007. Generation's effective tax rate decreased primarily as a result of recording tax benefits on realized and unrealized losses in its qualified nuclear decommissioning fund investments. The tax benefits on the realized and unrealized losses discussed above were recorded at a higher statutory tax rate than Generation's remaining income from operations. See Note 11 of the Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. The effective tax rate was 40.2% for 2007 compared to 38.2% for 2006. The increase in the effective tax rate was attributable to an increase in deferred tax expense associated with the generation portion of ComEd's research and development settlement as well as ComEd's and PECO's application of the indirect cost capitalization method settlement guidelines recorded in the fourth quarter of 2007. In addition, realized gains recognized in the fourth quarter of 2007 by the qualified nuclear decommissioning trusts also contributed to the increase in the effective tax rate. See Note 12 of the Notes to Consolidated Financial Statements for further details of the components of the effective income tax rates.

Discontinued Operations.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007. During 2008, Generation reduced its guarantee liabilities and recognized $38 million of income in discontinued operations related to the expiration of tax indemnifications in connection to a prior investment in Sithe Energies, Inc. (Sithe).

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006. For 2007 as compared to 2006, Generation's Consolidated Statement of Income for 2007 reflects a $4 million (after-tax) gain on the disposal of discontinued operations related primarily to Sithe, resulting from a settlement agreement between a subsidiary of Sithe, the Pennsylvania Attorney General's Office and the Pennsylvania Department of Revenue regarding a previously disputed tax position asserted for the 2000 tax year. Generation's Consolidated Statement of Income and Comprehensive Income for 2006 reflected a $4 million (after-tax) gain on disposal of discontinued operations.

See Note 2 of the Notes to Consolidated Financial Statements for further information regarding the presentation of Sithe as discontinued operations.

Results of Operations—ComEd

	2008	2007	Favorable (Unfavorable) variance 2008 vs. 2007	2006	Favorable (Unfavorable) variance 2007 vs. 2006
Operating revenues	$6,136	$6,104	$ 32	$6,101	$ 3
Purchased power expense	3,582	3,747	165	3,292	(455)
Revenue net of purchased power expense	2,554	2,357	197	2,809	(452)
Other operating expenses					
Operating and maintenance	1,125	1,091	(34)	745	(346)
Impairment of goodwill	—	—	—	776	776
Depreciation and amortization	464	440	(24)	430	(10)
Taxes other than income	298	314	16	303	(11)
Total other operating expenses	1,887	1,845	(42)	2,254	409
Operating income	667	512	155	555	(43)
Other income and deductions					
Interest expense, net	(348)	(318)	(30)	(308)	(10)
Equity in losses of unconsolidated affiliates	(8)	(7)	(1)	(10)	3
Other, net	18	58	(40)	96	(38)
Total other income and deductions	(338)	(267)	(71)	(222)	(45)
Income before income taxes	329	245	84	333	(88)
Income taxes	128	80	(48)	445	365
Net income (loss)	$ 201	$ 165	$ 36	$ (112)	$ 277

Net Income.

Year ended December 31, 2008 Compared to Year Ended December 31, 2007. As more fully described below, ComEd's net income for 2008 compared to 2007 reflected higher revenue net of purchased power expense, primarily driven by higher transmission rates

effective May 1, 2007 and June 1, 2008 and higher distribution rates effective September 16, 2008. In 2008, ComEd received a refund of Illinois Distribution Tax that also contributed to the increase in net income. These increases were partially offset by unfavorable weather; higher operating and maintenance expense, principally driven by disallowances arising from the 2007 Rate Case order and higher storm costs; higher depreciation and amortization expense; and higher interest expense.

Year ended December 31, 2007 Compared to Year Ended December 31, 2006. As more fully described below, ComEd's net income (loss) for 2007 compared to 2006 reflected the impact of a goodwill impairment charge in 2006 partially offset by higher purchased power expense, higher operating and maintenance expense, and the impacts of the 2006 benefits associated with reversing previously incurred expenses as a result of the July and December 2006 ICC rate orders. In 2007, ComEd incurred increased costs associated with transitioning from the rate freeze period, including implementing the rate relief programs.

Operating Revenues and Purchased Power Expense. ComEd evaluates its operating performance using the measure of revenue net of purchased power expense. ComEd believes revenue net of purchased power is a useful measurement of its performance because it provides information that can be used to evaluate its operational performance. In general, effective January 2, 2007, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, the revenue net of purchased power figures are 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.

Year ended December 31, 2008 Compared to Year Ended December 31, 2007.

The changes in operating revenues, purchased power expense and revenue net of purchased power expense for 2008 compared to 2007 consisted of the following:

	Increase (Decrease)		
	Operating Revenues	Purchased Power	Revenue Net of Purchased Power
Retail energy and customer choice	$(98)	$(108)	$ 10
Transmission	65	11	54
Volume—delivery	2	n/a	2
Weather—delivery	(38)	n/a	(38)
Wholesale contracts	(58)	(64)	6
Rate relief program	27	n/a	27
Energy efficiency and demand response programs	25	n/a	25
2007 Distribution Rate Case	75	n/a	75
2007 City of Chicago Settlement	5	n/a	5
Other	27	(4)	31
Total (decrease) increase	$ 32	$(165)	$197

Retail energy and customer choice

Revenue net of purchased power for 2008 compared to 2007 reflects the one-day impact of lower retail rates for January 1, 2007 before the expiration of the rate freeze and implementation of the rate increase on January 2, 2007.

Revenue. All ComEd customers have the choice to purchase electricity from a competitive electric supplier. This choice does not impact the volume of deliveries, but affects revenue collected from customers related to supplied electricity and generation service. Customer choice does not affect ComEd's operating income because the cost of the procured power is passed along to customers without mark-up. As of December 31, 2008, several competitive electric suppliers had been granted approval to serve retail electricity customers in the ComEd service territory. There are currently a minimal number of residential customers being served by alternative suppliers.

For the year ended December 31, 2008 and 2007, 51% and 48%, respectively, of electricity delivered to ComEd's retail customers was provided by competitive electric generation suppliers.

	2008	2007
Retail customers purchasing electricity from a competitive electric supplier:		
Number of customers at period end	43,100	44,200
Percentage of total retail customers	1%	1%
Volume (GWhs)	46,950	45,020
Percentage of total retail deliveries	51%	48%

Purchased Power. The decrease in purchased power expense from customer choice was primarily due to the impact of ComEd customers electing to purchase electricity from a competitive electric generation supplier.

Transmission

Revenue. ComEd has a FERC-approved formula rate for its transmission rates. ComEd experienced increased revenue in 2008 due to the impact of higher transmission rates effective May 1, 2007 and June 1, 2008. See Note 3 of the Notes to the Consolidated Financial Statements for more information.

Purchased Power. Effective December 1, 2004, PJM members became obligated to pay Seams Elimination Charge/Cost Adjustments/Assignment (SECA) collections to ComEd and ComEd became obligated to pay SECA charges, because ComEd is both a transmission owner and a load-serving entity within PJM. ComEd recorded SECA collections and payments on a net basis through purchased power expense. These charges were subject to refund and dispute before FERC. The increase in purchased power expense during 2008 is due to the impact of a reduction of SECA reserves for potential refunds, which were recorded in 2007. Management of ComEd believes that appropriate reserves representing management's best estimate have been established in the event that some portion of the remaining SECA collections that are not settled are required to be refunded.

Volume—Delivery

Revenue. While ComEd's delivery volumes, exclusive of the effects of weather increased slightly compared to 2007 on a full year basis, during the fourth quarter of 2008 ComEd experienced a decrease in volumes. ComEd believes the trend from the fourth quarter will continue in 2009, due to the economic downturn.

Weather—Delivery

Revenue. Revenues were lower due to unfavorable weather conditions in 2008 compared to the same period in 2007. 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. Degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business in ComEd's service territory. Cooling degree days were 25% lower for 2008 compared to 2007, partially offset by an 11% increase in heating degree days.

Wholesale Contracts

Revenue. ComEd's revenues decreased $58 million primarily due to the expiration of certain wholesale contracts in 2007.

Purchased Power. ComEd's purchased power decreased $64 million primarily due to the expiration of certain wholesale contracts in 2007.

Rate relief program

Revenue. ComEd funded less rate relief credits to customers in 2008 compared to 2007. Credits provided to customers are recorded as a reduction to operating revenues; therefore, the reduction in credits resulted in an increase in revenues for 2008. See Note 3 of the Notes to the Consolidated Financial Statements for more information.

Energy efficiency and demand response programs

Revenue. As a result of the 2007 Illinois Settlement, utilities are allowed recovery of costs for energy efficiency and demand response programs beginning June 1, 2008. During the year ended December 31, 2008, ComEd recognized $25 million of revenue associated with these programs. This amount was offset by an equal amount of operating and maintenance expense. See Note 3 of the Notes to the Consolidated Financial Statements for more information.

2007 Distribution Rate Case

Revenue. 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 a $75 million increase in revenues for 2008 compared to 2007. See Note 3 of the Notes to the Consolidated Financial Statements for more information.

2007 City of Chicago Settlement

Revenue. ComEd paid $18 million and $23 million in 2008 and 2007, respectively, under the terms of its 2007 settlement agreement with the City of Chicago. Payments are recorded as a reduction in revenues; therefore, the lower payment resulted in a net increase in revenues for 2008. See Note 3 of the Notes to Consolidated Financial Statements for more information.

Year ended December 31, 2007 Compared to Year Ended December 31, 2006.

The changes in operating revenues, purchased power expense and revenue net of purchased power expense for 2007 compared to 2006 consisted of the following:

	Increase (Decrease)		
	Operating Revenues	Purchased Power	Revenue Net of Purchased Power
Rate changes and mix	$ 748	$1,346	$(598)
Rate relief program	(33)	n/a	(33)
Transmission	115	(17)	132
Weather	141	83	58
Delivery Volume	20	n/a	20
Customer Choice	(917)	(917)	n/a
Wholesale contracts	(64)	(50)	(14)
2007 City of Chicago Settlement	(23)	n/a	(23)
Other	16	10	6
Total increase (decrease)	$ 3	$ 455	$(452)

Rate changes and mix

Revenue. The increase in revenue related to rate changes and mix primarily reflects the end of the rate freeze and the implementation of market-based rates for electricity and the impact of the distribution rate increase effective January 2, 2007. In 2006, most customers were charged a bundled rate that included distribution, transmission services and the cost of electricity. Additionally, under Illinois law, no competitive transition charges (CTCs) are permitted to be collected after 2006. As of January 2007, ComEd began billing customers on an unbundled basis, which includes separate charges for distribution, transmission and electricity. Given the relatively small increase of $83 million approved by the ICC in the annual distribution revenue requirements, the majority of the change in year-over-year pricing was driven by the inclusion of market-based electricity rates. The market-based electricity rates were determined through a reverse-auction competitive bidding process. See Note 3 of the Notes to Consolidated Financial Statements for more information. Additionally starting in 2007, ComEd began recovering former manufactured gas plant remediation costs from customers.

Purchased Power. Purchased power increased due to higher electricity prices. The PPA with Generation terminated at the end of 2006. In 2007, as a result of the ICC-approved reverse-auction process, ComEd began procuring electricity, including ancillary services, under supplier forward contracts and from PJM-administered wholesale electricity markets. See Note 3 of the Notes to Consolidated Financial Statements for more information on the reverse-auction process.

Rate Relief Programs

Revenue. As part of its programs for customer rate relief approved and included in the 2007 Illinois Settlement, ComEd funded a portion of the credits issued to customers. These credits are recorded as a reduction of revenues when issued to customers. See Note 3 of the Notes to Consolidated Financial Statements for more information on the Rate Relief Programs.

Transmission

Revenue. In 2007, ComEd experienced increased revenue from the provision of transmission services resulting from increased peak and kWh load within the ComEd service territory. Additionally, FERC issued an order in ComEd's transmission rate case conditionally approving ComEd's proposal to implement a formula-based transmission rate and associated rate increase effective May 1, 2007, subject to refund. See Note 3 of the Notes to Consolidated Financial Statements for more information on the Transmission Rate Case.

Purchased Power. In 2006, ComEd recorded $5 million of net SECA collections. Also during 2006, ComEd adjusted its reserve for possible SECA refunds. In 2007, based on FERC approval of certain settlements, ComEd reduced its reserve for possible SECA refunds to reflect management's best estimate of the remaining amounts that will ultimately be required to be refunded. Management of ComEd believes that appropriate reserves have been established in the event that some portion of the remaining SECA collections that are not settled are required to be refunded.

Weather

Revenue. Revenues were higher due to favorable weather conditions for 2007 compared to 2006. In ComEd's service territory, heating degree days were 8% higher and cooling degree days were 19% higher during 2007 compared to 2006.

Purchased Power. The increase in purchased power expense attributable to weather resulted from higher demand due to favorable weather conditions in the ComEd service territory relative to the prior year.

Delivery volume

Revenue. The increase in revenues for the provision of distribution services primarily resulted from an increase in deliveries, excluding the effects of weather, due to an increased number of customers.

Customer Choice

Revenue. For the year ended December 31, 2007 and 2006, 48% and 23%, respectively, of electricity delivered to ComEd's retail customers was provided by competitive electric generation suppliers.

	2007	2006
Retail customers purchasing electricity from a competitive electric generation supplier:		
Number of customers at period end	44,200	19,600
Percentage of total retail customers	1%	(a)
Volume (GWhs)	45,020	20,787
Percentage of total retail deliveries	48%	23%

(a) Less than one percent.

Purchased Power. The decrease in purchased power expense from customer choice was primarily due to more ComEd non-residential customers electing to purchase electricity from a competitive electric generation supplier.

Wholesale Contracts

Revenue. ComEd's revenue decreased $64 million as a result of certain wholesale contracts expiring in May 2007.

Purchased Power. ComEd's purchased power decreased $50 million as a result of certain wholesale contracts expiring in May 2007.

2007 City of Chicago Settlement

Revenue. ComEd paid $23 million under the terms of its 2007 settlement agreement with the City of Chicago, which was recorded as a reduction of revenue. See Note 3 of the Notes to Consolidated Financial Statements for more information.

Operating and Maintenance Expense.

The changes in operating and maintenance expense for 2008 compared to 2007, consisted of the following:

	Increase (Decrease)
Energy efficiency and demand response programs [(a)]	$ 25
2007 Rate Case order [(b)]	22
Wages and salaries	15
Allowance for uncollectible accounts expense [(c)]	12
Storm-related costs	8
Corporate allocations	6
Post rate freeze period transition expenses incurred in 2007	(26)
Contracting	(23)
Injuries and damages	(9)
Other	4
Increase in operating and maintenance expense	$ 34

(a) These items are offset by an equal increase in revenues. See Note 3 of the Notes to the Consolidated Financial Statements for more information.

(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 operating and maintenance expenses. See Note 3 of the Notes to the Consolidated Financial Statements for more information.

(c) The allowance for uncollectible accounts expense increased during 2008 due to increased customer account charge-offs and the impact of rate relief credits that reduced this expense during 2007. Management believes the current overall negative economic conditions contributed to the increase in uncollectible accounts expense in 2008 and may negatively impact future uncollectible accounts expense relative to historical levels.

The changes in operating and maintenance expense for 2007 compared to 2006, consisted of the following:

	Increase (Decrease)
ICC rate order [(a)]	$201
Contracting	31
Allowance for uncollectible accounts expense [(b)]	26
Wages and salaries	23
Storm-related costs	19
Fringe benefits [(c)]	14
Corporate allocations	11
Materials and supplies expense	8
Post rate freeze period transition expenses [(d)]	7
Postage	7
Other	(1)
Increase in operating and maintenance expense	$346

(a) As a result of the July 2006 ICC rate order and the December 2006 ICC rehearing order in 2006, ComEd recorded one-time benefits associated with reversing previously incurred expenses including severance costs, manufactured gas plant (MGP) costs, procurement case and rate case costs.

(b) This increase resulted from a change in collectability assumptions in response to changes in the customer payment patterns, changes in customer prices, changes in termination practices and certain changes in business and economic conditions.

(c) Reflects increases in various fringe benefits primarily due to increased pension and other postretirement benefits costs.
(d) Includes increased costs associated with the Rate Relief programs and other costs associated with transitioning to the post rate freeze period. See Note 3 of the Notes to Consolidated Financial Statements for more information.

Impairment of Goodwill. ComEd performs an assessment of goodwill for impairment at least annually, or more frequently if events or circumstances indicate that goodwill might be impaired. The assessment compares the carrying value of goodwill to the estimated fair value of goodwill as of a point in time. The estimated fair value incorporates management's assessment of current events and expected future cash flows.

Year ended December 31, 2008 Compared to Year Ended December 31, 2007. ComEd's 2008 annual goodwill impairment assessment, performed in the fourth quarter, resulted in no additional impairment.

Year ended December 31, 2007 Compared to Year Ended December 31, 2006. During the third quarter of 2006, ComEd completed an interim assessment of goodwill for impairment purposes to reflect the adverse affects of the ICC's July 2006 rate order. The assessment indicated that ComEd's goodwill was impaired and a charge of $776 million was recorded. ComEd's 2007 annual goodwill impairment assessment, which was performed in the fourth quarter, resulted in no additional impairment. ComEd had approximately $2.6 billion of remaining goodwill as of December 31, 2007. See Note 7 of the Notes to the Consolidated Financial Statements for additional information.

Depreciation and Amortization Expense.

The changes in depreciation and amortization expense for 2008 compared to 2007 and 2007 compared to 2006, consisted of the following:

	Increase (Decrease) 2008 vs. 2007	Increase (Decrease) 2007 vs. 2006
Depreciation expense associated with higher plant balances	$19	$ 15
2007 Rate Case asset disallowances	2 [(a)]	—
Other amortization expense	3	(5)
Increase in depreciation and amortization expense	$24	$ 10

(a) In September 2008, as a result of the 2007 Rate Case order, ComEd recorded $37 million of fixed asset disallowances; $2 million was recorded as depreciation expense.

Taxes Other Than Income.

Year ended December 31, 2008 Compared to Year Ended December 31, 2007. Taxes other than income decreased for 2008 compared to 2007 primarily as a result of a $14 million refund of 2005 Illinois distribution tax received in 2008.

Year ended December 31, 2007 Compared to Year Ended December 31, 2006. Taxes other than income increased for 2007 compared to 2006 primarily as a result of a $7 million refund of Illinois distribution tax received in 2006.

Interest Expense, Net.

The changes in interest expense for 2008 compared to 2007 and 2007 compared to 2006 consisted of the following:

	Increase (Decrease) 2008 vs. 2007	Increase (Decrease) 2007 vs. 2006
Interest expense related to uncertain tax positions	$ 3 [(a)]	$(32) [(a)]
Interest expense on debt	29 [(b)]	19 [(b)]
Amortization of debt-related costs	—	20 [(c)]
Other	(2)	3
Increase in interest expense, net	$ 30	$ 10

(a) ComEd adopted FIN 48 on January 1, 2007. See Note 11 of the Notes of the Consolidated Financial Statements for more information.
(b) The increase resulted from higher debt balances.
(c) In 2007, ComEd's interest expense, net reflected the initial amortization of the regulatory asset related to the early debt retirement costs authorized by the ICC in 2006.

Other, Net.

The changes in other, net for 2008 compared to 2007 and 2007 compared to 2006 consisted of the following:

	Increase (Decrease) 2008 vs. 2007	Increase (Decrease) 2007 vs. 2006
ICC rate order	$—	$(87) [a]
Interest income related to uncertain tax positions	(36) [b]	41 [b]
Gain on disposal of assets and investments, net	—	4
Other	(4)	4
Decrease in other, net	$(40)	$(38)

(a) As a result of the July 2006 ICC rate order, ComEd recorded a benefit associated with reversing previously incurred expenses to retire debt early.
(b) ComEd adopted FIN 48 on January 1, 2007. See Note 11 of the Notes of the Consolidated Financial Statements for more information.

Effective Income Tax Rate.

Year ended December 31, 2008 Compared to Year Ended December 31, 2007. ComEd's effective income tax rate for 2008 was 38.9% compared to 32.7% for 2007. This increase in the effective tax rate was primarily due to a benefit recorded for the indirect cost capitalization method change in 2007. See Note 11 of the Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates

Year ended December 31, 2007 Compared to Year Ended December 31, 2006. The effective income tax rate was 32.7% for 2007, compared to 133.6% for 2006. The decrease in the effective tax rate was primarily due to the non-deductible impairment charge in 2006 associated with ComEd's goodwill accounting. The non-deductible goodwill impairment charge decreased income (loss) before income taxes which increased the effective tax rate from continuing operations by 81.6% in 2006. The balance of the reduction was due to a benefit recorded for the indirect cost capitalization change in 2007. See Note 11 of the 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 (in GWhs)	2008	2007	% Change 2008 vs. 2007	2006	% Change 2007 vs. 2006
Full service [a]					
Residential	28,389	29,374	(3.4)%	28,330	3.7%
Small commercial & industrial	14,937	16,468	(9.3)%	26,597	(38.1)%
Large commercial & industrial	1,045	1,949	(46.4)%	12,595	(84.5)%
Public authorities & electric railroads	578	766	(24.5)%	2,254	(66.0)%
Total full service	44,949	48,557	(7.4)%	69,776	(30.4)%
Delivery only [b]					
Residential [c]	—	—	n.m	—	n.m.
Small commercial & industrial	18,550	17,380	6.7%	5,505	215.7%
Large commercial & industrial	27,764	27,122	2.4%	15,282	77.5%
Public authorities & electric railroads	636	518	22.8%	—	100.0%
Total delivery only	46,950	45,020	4.3%	20,787	116.6%
Total retail deliveries	91,899	93,577	(1.8)%	90,563	3.3%

(a) Full service reflects deliveries to customers purchasing electricity directly from ComEd.
(b) Delivery only service reflects customers electing to receive electricity from a competitive electric generation supplier.
(c) As of December 31, 2008, there are a minimal number of residential customers being served by alternative suppliers with total activity of less than 1 GWh and $1 million.

n.m. Not meaningful.

Electric Revenue	2008	2007	% Change 2008 vs. 2007	2006	% Change 2007 vs. 2006
Full service [(a)]					
Residential	$3,284	$3,161	3.9%	$2,453	28.9%
Small commercial & industrial	1,542	1,619	(4.8)%	2,060	(21.4)%
Large commercial & industrial	90	154	(41.6)%	700	(78.0)%
Public authorities & electric railroads	52	67	(22.4)%	137	(51.1)%
Total full service	4,968	5,001	(0.7)%	5,350	(6.5)%
Delivery only [(b)]					
Residential [(c)]	—	—	n.m	—	n.m.
Small commercial & industrial	289	261	10.7%	85	207.1%
Large commercial & industrial	295	276	6.9%	155	78.1%
Public authorities & electric railroads	7	5	40.0%	—	n.m.
Total delivery only	591	542	9.0%	240	125.8%
Total electric retail revenues	5,559	5,543	0.3%	5,590	(0.8)%
Other revenue [(d)]	577	561	2.9%	511	9.8%
Total electric and other revenue	$6,136	$6,104	0.5%	$6,101	n.m.

(a) Full service reflects deliveries to customers purchasing electricity directly from ComEd, which include the cost of electricity and the cost of transmission and distribution of the electricity.
(b) Delivery only revenue reflects revenue under tariff rates from customers electing to receive electricity from a competitive electric generation supplier.
(c) As of December 31, 2008, there are a minimal number of residential customers being served by alternative suppliers with total activity of less than 1 GWh and $1 million.
(d) Other revenues include transmission revenue (including revenue from PJM), sales to municipalities and other wholesale energy sales.

n.m. Not meaningful.

Results of Operations—PECO

	2008	2007	Favorable (unfavorable) Variance 2008 vs. 2007	2006	Favorable (unfavorable) Variance 2007 vs. 2006
Operating revenues	$5,567	$5,613	$ (46)	$5,168	$ 445
Purchased power expense and fuel expense	3,018	2,983	(35)	2,702	(281)
Revenue net of purchased power expense and fuel expense	2,549	2,630	(81)	2,466	164
Other operating expenses					
Operating and maintenance	731	630	(101)	628	(2)
Depreciation and amortization	854	773	(81)	710	(63)
Taxes other than income	265	280	15	262	(18)
Total other operating expenses	1,850	1,683	(167)	1,600	(83)
Operating income	699	947	(248)	866	81
Other income and deductions					
Interest expense, net	(226)	(248)	22	(266)	18
Equity in losses of unconsolidated affiliates	(16)	(7)	(9)	(9)	2
Other, net	18	45	(27)	30	15
Total other income and deductions	(224)	(210)	(14)	(245)	35
Income before income taxes	475	737	(262)	621	116
Income taxes	150	230	80	180	(50)
Net income	325	507	(182)	441	66
Preferred stock dividends	4	4	—	4	—
Net income on common stock	$ 321	$ 503	$(182)	$ 437	$ 66

Net Income.

Year ended December 31, 2008 Compared to Year Ended December 31, 2007. PECO's net income for 2008 compared to 2007 decreased due to lower operating revenues net of purchased power and fuel expense, reflecting unfavorable weather conditions, as well as higher operating and maintenance expenses primarily driven by an increase in the allowance for uncollectible accounts expense and increased scheduled CTC amortization, which was in accordance with the 1998 restructuring settlement mandated by the Competition Act, partially offset by the decrease in interest expense due to lower long-term debt balances owed to PECO Energy Transition Trust (PETT).

Year ended December 31, 2007 Compared to Year Ended December 31, 2006. PECO's net income for 2007 compared to 2006 increased primarily due to higher operating revenues net of purchased power and fuel expense, which reflected increased sales from favorable weather conditions, increased usage across all customer classes for both electric and gas, the completion of certain authorized rate increases that began in 2006 and the favorable settlement of a PJM billing dispute, as well as the recognition of income resulting from a reduction in the reserve after the successful PURTA tax appeal, partially offset by higher scheduled CTC amortization, which was in accordance with the 1998 restructuring settlement mandated by the Competition Act.

Operating Revenues, Purchased Power and Fuel Expense. PECO evaluates its operating performance using the measures of revenue net of purchased power for electric and revenue net of fuel expense for gas. PECO believes revenue net of purchased power and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its operational performance. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power and 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.

Year ended December 31, 2008 Compared to Year Ended December 31, 2007.

The changes in PECO's operating revenues, purchased power and fuel expense and revenue net of purchased power and fuel expense for 2008 compared to 2007 consisted of the following:

	Increase (Decrease)								
	Electric			Gas			Total		
	Operating Revenues	Purchased Power	Net	Operating Revenues	Fuel Expense	Net	Operating Revenues	Purchased Power and Fuel Expense	Net
Weather	$(84)	$(36)	$(48)	$(26)	$(20)	$ (6)	$(110)	$(56)	$(54)
Pricing	(1)	28	(29)	—	—	—	(1)	28	(29)
Settlement of PJM billing dispute	—	10	(10)	—	—	—	—	10	(10)
Transmission	(4)	7	(11)	—	—	—	(4)	7	(11)
Volume	27	13	14	(11)	(11)	—	16	2	14
Rate increases	8	8	—	54	54	—	62	62	—
Customer choice	6	6	—	—	—	—	6	6	—
Spot market activity	9	9	—	—	—	—	9	9	—
Off-system gas activity	—	—	—	(25)	(27)	2	(25)	(27)	2
Other	10	—	10	(9)	(6)	(3)	1	(6)	7
Total increase (decrease)	$(29)	$ 45	$(74)	$(17)	$(10)	$ (7)	$ (46)	$ 35	$(81)

Weather

Revenues. 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 other 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. Revenues were lower due to unfavorable weather conditions in PECO's service territory, where heating degree days and cooling degree days were 3% and 11% lower, respectively. Heating degree days and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool, respectively, a home or business.

Purchased Power and Fuel Expense. The decrease in purchased power and fuel expense attributable to weather was due to lower demand as a result of unfavorable weather conditions in the PECO service territory relative to the prior year.

Pricing

Revenues. The decrease in electric revenues as a result of pricing reflected the reduction in distribution rates, for a total of $36 million, made to refund the PURTA tax settlement to customers. This rate change had no impact on operating income because it was offset by the amortization of the regulatory liability related to the PURTA tax settlement that is reflected in taxes other than income. The decrease was partially offset by an increase in revenues of approximately $28 million related to higher energy market prices charged to certain large commercial and industrial customers (this increase is completely offset by a related increase in purchased power expense and has no impact on PECO's operating income), as well as other factors that were not individually significant.

Purchased Power. The increase in purchased power as a result of pricing reflected the increased market prices for electricity, at which PECO procures electricity on behalf of certain large commercial and industrial customers.

Settlement of PJM Billing Dispute

Purchased Power. PECO's purchased power increased $10 million due to the impact of the favorable settlement of a PJM billing dispute with PPL during 2007.

Transmission

Revenues. Transmission revenue represents revenue earned by PECO as a transmission owner for the use of PECO's transmission facilities in PJM. Wholesale transmission revenue received from PJM decreased in 2008 as this revenue is based on the prior year's summer peak, and the summer peak in 2007 was lower than the summer peak in 2006.

Purchased Power. Transmission expenses represent wholesale transmission costs and other costs allocated by PJM, including charges for transmission system stabilization, default charges and regional transmission expansion plan costs. The increase in transmission expense was due to increased allocated costs from PJM related to charges for transmission system stabilization, partially offset by decreased wholesale transmission costs.

Volume

Revenues. The increase in electric revenues as a result of higher delivery volume, exclusive of the effects of weather and customer choice, reflected increased usage across the residential customer class and the impact of an increased number of electric customers in all customer classes. The decrease in gas revenues as a result of lower delivery volume, exclusive of the effects of weather and customer choice, reflected decreased usage across the residential and small commercial and industrial customer classes.

During the fourth quarter of 2008, PECO experienced a decrease in volume, exclusive of the effects of weather and customer choice, and believes this trend may continue in 2009 due to the economic downturn.

Purchased Power and Fuel Expense. The increase in purchased power as a result of higher delivery volume, exclusive of the effects of weather and customer choice, reflected increased usage across the residential customer class and the impact of an increased number of electric customers in all customer classes. The decrease in fuel expense as a result of lower delivery volume, exclusive of the effects of weather and customer choice, reflected decreased usage across the residential and small commercial and industrial customer classes.

Rate increases

Revenues. The increase in electric revenues attributable to electric rate increases reflected the impact of the scheduled generation rate increase that became effective in mid-January 2007 and remained in effect throughout 2008. This electric generation rate increase represented the last scheduled rate increase through 2010 under PECO's 1998 restructuring settlement. This rate increase did not affect operating income as PECO incurred corresponding and offsetting purchased power expense under its PPA with Generation. The increase in gas revenues was due to higher realized prices for natural gas, which reflected PAPUC-approved rates adjusted quarterly in accordance with the purchased gas cost clause. The average purchased gas cost rate per million cubic feet in effect for 2008 was 11% higher than the average rate for 2007.

Purchased Power and Fuel Expense. The increase in purchased power attributable to electric rate increases reflected the impact of the completion of the last scheduled generation rate increase under the PPA with Generation in mid-January 2007. The increase in fuel expense reflected higher realized natural gas prices.

Customer choice

Revenues and Purchased Power. 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 and generation service. PECO's operating income is not affected by customer choice since any increase or decrease in revenues is completely offset by any related increase or decrease in purchased power expense.

	2008	2007
Retail customers purchasing energy from a competitive electric generation supplier:		
Number of customers at period end	24,800	29,200
Percentage of total retail customers	2%	2%

The increase in electric revenue and purchase power expense associated with customer choice reflected increased usage, exclusive of the effects of weather, primarily from the small commercial and industrial customer class and customers, primarily from the small commercial and industrial customer class, returning to PECO as their electric supplier.

Spot market activity

Revenues. Spot market electricity sales revenue results from surplus hourly energy that occurs whenever the energy supply scheduled in the day-ahead market to serve the expected load exceeds the actual load on the delivery day. Spot market revenue is passed through as a credit to purchased power expense to Generation in accordance with the PPA.

Purchased Power. Spot market electricity purchases result from scheduled energy transactions that are insufficient to cover the actual load and, occurs whenever the energy supply scheduled in the day-ahead market to serve the expected load is not enough to serve the actual load on the delivery day. Also, spot market purchased power expense reflects the net spot market sales and purchases activity that is passed through to Generation in accordance with the PPA. Therefore, spot market activity has no impact on PECO's operating income.

Off-system gas activity

Revenues. Off-system gas sales revenues represent sales of excess gas supply on the wholesale market and the release of pipeline capacity.

Fuel Expense. Fuel expense related to off-system gas sales includes the cost of gas sold in the wholesale market.

Other

Revenues. The increase in other electric revenues reflects various factors, none of which were individually significant. The decrease in other gas revenues reflects decreased late payment fees and other various factors, none of which were individually significant.

Fuel Expense. The decrease in other fuel expense reflects various factors, none of which were individually significant.

Year ended December 31, 2007 Compared to Year Ended December 31, 2006.

The changes in PECO's operating revenues, purchased power and fuel expense and revenue net of purchased power and fuel expense for 2007 compared to 2006 consisted of the following:

	Increase (Decrease)								
	Electric			Gas			Total		
	Operating Revenues	Purchased Power	Net	Operating Revenues	Fuel Expense	Net	Operating Revenues	Purchased Power and Fuel Expense	Net
Weather	$108	$ 47	$ 61	$ 119	$ 98	$ 21	$227	$145	$ 82
Pricing	(20)	(3)	(17)	—	—	—	(20)	(3)	(17)
Settlement of PJM billing dispute	—	(10)	10	—	—	—	—	(10)	10
Transmission	4	(1)	5	—	—	—	4	(1)	5
Volume	82	32	50	4	6	(2)	86	38	48
Rate increases (decreases)	195	184	11	(114)	(114)	—	81	70	11
Customer choice	8	8	—	—	—	—	8	8	—
Spot market activity	7	7	—	—	—	—	7	7	—
Off-system gas activity	—	—	—	22	21	1	22	21	1
Other	19	(2)	21	11	8	3	30	6	24
Total increase	$403	$262	$141	$ 42	$ 19	$ 23	$445	$281	$164

Weather

Revenues. Revenues were higher due to favorable weather conditions in PECO's service territory, where heating degree days and cooling degree days were 16% and 15% higher, respectively.

Purchased Power and Fuel Expense. The increase in purchased power and fuel expense attributable to weather was due to higher demand as a result of favorable weather conditions in the PECO service territory relative to the prior year.

Pricing

Revenues. The decrease in electric revenues as a result of pricing primarily reflected the effects of rate blocking, whereby customer charges per unit of energy delivered were reduced when usage by certain commercial and industrial customers exceeds a certain

threshold. Lower energy market prices charged to certain large commercial and industrial customers also contributed to the decrease in revenues, but as this decrease is completely offset by a related decrease in purchased power expense, it did not impact PECO's operating income.

Purchased Power. The decrease in purchased power as a result of pricing reflected the decreased market prices for electricity, at which PECO procures electricity on behalf of certain large commercial and industrial customers.

Settlement of PJM billing dispute

Purchased Power. PECO's purchased power expense decreased $10 million due to the favorable settlement of a PJM billing dispute with PPL in 2007.

Transmission

Revenues. Transmission revenues represent revenue earned by PECO as a transmission owner. PECO earns revenue through PJM for the use of PECO's transmission facilities. Wholesale transmission revenue received from PJM increased in 2007 as this revenue is based on the prior year's summer peak, and the summer peak in 2006 was higher than the summer peak in 2005.

Purchased Power. Transmission expenses represent wholesale transmission costs and other costs allocated by PJM.

Volume

Revenues. The increase in revenues as a result of higher delivery volume, exclusive of the effects of weather and customer choice, reflected increased usage across all customer classes for electric and gas and the impact of an increased number of electric customers in all customer classes and gas customers in the residential and small commercial and industrial classes.

Purchased Power and Fuel Expense. The increase in expenses as a result of higher delivery volume, exclusive of the effects of weather and customer choice, reflected increased usage across all customer classes for electric and gas and the impact of an increased number of electric customers in all customer classes and gas customers in the residential and small commercial and industrial classes

Rate increases (decreases)

Revenues. The increase in electric revenues attributable to electric rate increases of $195 million reflected $184 million related to a scheduled electric generation rate increase, which was effective for customer bills for electric generation service delivered after customers' January 2007 meter readings. This electric generation rate increase represented the last scheduled rate increase through 2010 under PECO's 1998 restructuring settlement. This rate increase did not affect operating income as PECO incurred corresponding and offsetting purchased power expense under its PPA with Generation. The increase in electric revenues attributable to electric rate increases also reflected $11 million associated with the completion in January 2007 of scheduled CTC and distribution rate increases that began in 2006. The decrease in gas revenues was due to lower realized market prices for natural gas, which reflected PAPUC-approved rates adjusted quarterly in accordance with the purchased gas cost clause. The average purchased gas cost rate per million cubic feet in effect for 2007 was 17% lower than the average rate for 2006.

Purchased Power and Fuel Expense. The increase in purchased power expense attributable to electric rate increases reflected the scheduled generation rate increase under the PPA with Generation, which directly offset the increase in revenues. The decrease in fuel expense reflected lower realized market prices for natural gas.

Customer choice

Revenues and Purchased Power. 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 and generation service. PECO's operating income is not affected by customer choice since any increase or decrease in revenues is completely offset by any related increase or decrease in purchased power expense.

	2007	2006
Retail customers purchasing energy from a competitive electric generation supplier:		
Number of customers at period end	29,200	34,400
Percentage of total retail customers	2%	2%

The increase in electric revenue and purchased power expense associated with customer choice reflected customers, primarily from the small commercial and industrial customer class, returning to PECO as their electric supplier.

Spot market activity

Revenues. Spot market electricity sales revenue results from surplus hourly energy that occurs whenever the energy supply scheduled in the day-ahead market to serve the expected load exceeds the actual load on the delivery day. Spot market revenue is passed through as a credit to purchased power expense to Generation in accordance with the PPA.

Purchased Power. Spot market electricity purchases result from scheduled energy transactions that are insufficient to cover the actual load and, occurs whenever the energy supply scheduled in the day-ahead market to serve the expected load is not enough to serve the actual load on the delivery day. Also, spot market purchased power expense reflects the net spot market sales and purchases activity that is passed through to Generation in accordance with the PPA. Therefore, spot market activity has no impact on PECO's operating income.

Off-system gas activity

Revenues. Off-system gas sales revenues represent sales of excess gas supply on the wholesale market and the release of pipeline capacity.

Fuel Expense. The fuel expense related to off-system gas sales includes the cost of gas sold in the wholesale market.

Other

Revenues. The increase in electric and gas revenues reflected increased late payment fees and other factors, none of which was individually significant.

Purchased Power and Fuel Expense. The decrease in purchased power expense and the increase in fuel expense were due to various factors, none of which was individually significant.

Operating and Maintenance Expense. The increase in operating and maintenance expense for 2008 compared to 2007 consisted of the following:

	Increase (Decrease)
Allowance for uncollectible accounts expense	$ 89
Wages and salaries	9
Fringe benefits	4
Contracting	1
Injuries and damages expense	(2)
Increase in operating and maintenance expense	$101

The increase in operating and maintenance expense for 2007 compared to 2006 consisted of the following:

	Increase (Decrease)
Allowance for uncollectible accounts expense	$ 13
Contracting [(a)]	12
Wages and salaries	9
Fringe benefits	6
Environmental reserve [(b)]	4
Injuries and damages expense [(c)]	3
Incremental storm-related costs	(39)
Severance-related expenses	(5)
PSEG merger integration costs incurred in 2006	(4)
Other	3
Increase in operating and maintenance expense	$ 2

(a) Reflects higher 2007 contracting expense primarily associated with vegetation management services and tax consulting.
(b) Reflects lower expense in 2006 due to a settlement related to a Superfund site.
(c) Reflects higher 2006 storm-related costs primarily associated with a significant storm in the third quarter of 2006.

Allowance for uncollectible accounts expense. The additional expense is primarily due to updated reserve estimates to reflect anticipated increases in customer account charge-offs associated with recent and upcoming increases in customer terminations, as well as, the further deterioration in actual and projected collections of PECO's higher risk customer accounts receivable. PECO experienced an increase in the aging of its high risk accounts receivable balances. The higher expense is in part as a result of a previous temporary suspension of certain collection processes during a billing system conversion project in 2006 and 2007. Finally, enrollment has also increased in customer assistance programs for low-income customers, which results in the eventual forgiveness of certain outstanding account balances. Management believes the current overall negative economic conditions are contributing to the increase in uncollectible accounts expense in 2008 and may negatively impact future uncollectible accounts expense relative to historical levels.

Depreciation and Amortization Expense. The increase in depreciation and amortization expense for 2008 compared to 2007 and 2007 compared to 2006 consisted of the following:

	Increase (Decrease) 2008 vs. 2007	Increase (Decrease) 2007 vs. 2006
CTC amortization [(a)]	$ 78	$69
Accelerated amortization of PECO billing system [(b)]	—	(9)
Other	3	3
Increase in depreciation and amortization expense	$ 81	$63

(a) PECO's CTC amortization is in accordance with its original settlement under the Pennsylvania Competition Act.
(b) In January 2005, as part of a broader systems strategy at PECO associated with the proposed merger with PSEG, Exelon's Board of Directors approved the implementation of a new customer information and billing system at PECO. The approval of this new system required the accelerated amortization of PECO's existing system through 2006 and the recognition of additional amortization expense of $9 million in 2006. The new system was implemented in 2006.

Taxes Other Than Income. The decrease in taxes other than income for 2008 compared to 2007 and the increase in 2007 compared to 2006 consisted of the following:

	Increase (Decrease) 2008 vs. 2007	Increase (Decrease) 2007 vs. 2006
PURTA Amortization [(a)]	$(36)	$—
Reduction of reserve related to PURTA tax appeal [(b)]	17	(17)
Sales and use tax	3	5
Taxes on utility revenues [(c)]	2	25
State franchise tax adjustment in 2006 [(d)]	—	7
Other	(1)	(2)
(Decrease) increase in taxes other than income	$(15)	$ 18

(a) The decrease is due to the amortization of the regulatory liability recorded in connection with the 2007 PURTA settlement which began in January 2008. The impact of the amortization on operating income is offset by lower revenues due to a reduction in the distribution rates to refund the PURTA taxes to customers.
(b) On March 27, 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 reduced the reserve associated with this matter.
(c) The increase in tax expense in 2008 compared to 2007 was due to a gross receipts tax rate increase that became effective on January 1, 2008, partially offset by a decrease in revenues. The increase in tax expense in 2007 compared to 2006 was due to the increase in revenues. These increases were offset by corresponding increases in revenues, as these taxes were collected from customers and remitted to the taxing authorities.
(d) Represents the reduction of tax accruals in 2006 following settlements related to prior year tax assessments.

Interest Expense, Net. The decrease in interest expense, net for 2008 compared to 2007 and 2007 compared to 2006 was primarily due to lower long-term debt balances 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.

Other, Net. The decrease in other, net for 2008 compared to 2007 was primarily due to the impacts of interest income recorded in 2007 as a result of the successful PURTA tax appeal and interest income recorded in 2007 related to the SSCM settlement, partially offset by an increase in interest income related to uncertain income tax positions. See Note 19 of the Notes to the Consolidated Financial Statements for additional details of the components of other, net.

The increase in other, net for 2007 compared to 2006 was primarily due to interest income recorded as a result of the successful PURTA tax appeal and interest income related to uncertain tax positions, partially offset by the impacts of a 2006 investment tax credit refund and a 2006 research and development credit refund. See Note 19 of the Notes to the Consolidated Financial Statements for additional details of the components of other, net.

Effective Income Tax Rate

Year ended December 31, 2008 Compared to Year Ended December 31, 2007. PECO's effective income tax rate was 31.6% for 2008 compared to 31.2% for 2007. The increase in the effective tax rate was primarily due to the impact of the benefit recorded for the indirect cost capitalization method change in 2007 partially offset by reduced income in 2008 while permanent differences remained relatively constant. See Note 11 of the Notes to the Consolidated Financial Statements for further details.

Year ended December 31, 2007 Compared to Year Ended December 31, 2006. PECO's effective income tax rate was 31.2% for 2007 compared to 29.0% for 2006. The increase in the effective tax rate was primarily due to an investment tax credit refund and a research and development credit refund in 2006, partially offset by the benefit recorded for the indirect cost capitalization method change in 2007. See Note 11 of the 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—(in GWhs)	2008	2007	% Change 2008 vs. 2007	2006	% Change 2007 vs. 2006
Full service [(a)]					
Residential	13,287	13,446	(1.2)%	12,796	5.1%
Small commercial & industrial	8,211	8,288	(0.9)%	7,818	6.0%
Large commercial & industrial	16,474	16,522	(0.3)%	15,898	3.9%
Public authorities & electric railroads	909	930	(2.3)%	906	2.6%
Total full service	38,881	39,186	(0.8)%	37,418	4.7%
Delivery only [(b)]					
Residential	30	42	(28.6)%	61	(31.1)%
Small commercial & industrial	469	571	(17.9)%	671	(14.9)%
Large commercial & industrial	3	14	(78.6)%	35	(60.0)%
Total delivery only	502	627	(19.9)%	767	(18.3)%
Total retail deliveries	39,383	39,813	(1.1)%	38,185	4.3%

(a) Full service reflects deliveries to customers purchasing electricity directly from PECO.
(b) Delivery only service reflects customers electing to receive electric generation service from a competitive electric generation supplier.

Electric Revenue	2008	2007	% Change 2008 vs. 2007	2006	% Change 2007 vs. 2006
Full service [a]					
Residential	$1,916	$1,948	(1.6)%	$1,780	9.4%
Small commercial & industrial	1,028	1,042	(1.3)%	943	10.5%
Large commercial & industrial	1,406	1,386	1.4%	1,286	7.8%
Public authorities & electric railroads	87	89	(2.2)%	83	7.2%
Total full service	4,437	4,465	(0.6)%	4,092	9.1%
Delivery only [b]					
Residential	2	4	(50.0)%	5	(20.0)%
Small commercial & industrial	25	30	(16.7)%	36	(16.7)%
Large commercial & industrial	—	—	0.0%	1	(100.0)%
Total delivery only	27	34	(20.6)%	42	(19.0)%
Total electric retail revenues	4,464	4,499	(0.8)%	4,134	8.8%
Other revenue [c]	282	276	2.2%	238	16.0%
Total electric and other revenue	$4,746	$4,775	(0.6)%	$4,372	9.2%

(a) Full service reflects deliveries to customers purchasing electricity directly from PECO, which includes the cost of energy, the cost of the transmission and the distribution of the energy and a CTC.

(b) Delivery only revenue reflects revenue from customers electing to receive generation service from a competitive electric generation supplier, which includes a distribution charge and a CTC.

(c) Other revenue includes transmission revenue from PJM and other wholesale energy sales.

PECO's Gas Sales Statistics and Revenue Detail

PECO's gas sales statistics and revenue detail were as follows:

Deliveries to customers (in million cubic feet (mmcf))	2008	2007	% Change 2008 vs. 2007	2006	% Change 2007 vs. 2006
Retail sales	56,110	58,968	(4.8)%	50.578	16.6%
Transportation	27,624	27,632	0.0%	25,527	8.3%
Total	83,734	86,600	(3.3)%	76,105	13.8%

Revenue	2008	2007	% Change 2008 vs. 2007	2006	% Change 2007 vs. 2006
Retail sales	$795	$784	1.4%	$770	1.8%
Transportation	19	17	11.8%	16	6.3%
Resales and other	7	37	(81.1)%	10	n.m.
Total gas revenue	$821	$838	(2.0)%	$796	5.3%

n.m. Not meaningful

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, $952 million and $574 million, respectively. Exelon, Generation, ComEd and PECO utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. In the second quarter

of 2008, ComEd established a new letter of credit facility to provide credit enhancement for certain tax exempt financings supported by first mortgage bonds. See the "Credit Matters" section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs 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. To manage cash flows and its capital structure, as more fully described below, ComEd did not pay a dividend in 2008, 2007 or 2006. 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. Future acquisitions that Exelon may undertake may involve external debt financing or the issuance of additional Exelon common stock. See Note 10 of the Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

Cash Flows from Operating Activities

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, customer choice, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, and their ability to achieve operating cost reductions. See Notes 3 and 18 of the Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

During 2008, Exelon's unfunded status of its pension plans increased significantly, primarily due to lower than expected 2008 asset returns, which is expected to result in increased benefit costs and required funding contributions in future years. Such increases could be material to 2009 and subsequent years. The Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, grants plan sponsors relief from funding requirements and benefit restrictions, and also provides some technical corrections to the Pension Protection Act of 2006 (the Act). One such technical correction, referred to as asset smoothing, allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements. Exelon has not yet determined whether it will elect this option. If Exelon elects the asset smoothing option, it would provide Exelon the opportunity to defer certain contributions to later years or potentially mitigate future contributions through market recovery. If Exelon does not elect the asset smoothing option, the minimum pension contributions as required under the Employee Retirement Income Security Act (ERISA) and the Act, as well as discretionary contributions to avoid benefit restrictions, are expected to be approximately $162 million, $1.6 billion, $1.5 billion and $664 million in 2009, 2010-2011, 2012-2013 and 2014, respectively, with an aggregate of $4 billion during the periods. If Exelon elected the asset smoothing option, the minimum pension contributions are expected to be approximately $162 million, $832 million, $2.6 billion and $578 million in 2009, 2010-2011, 2012-2013 and 2014, respectively, with an aggregate of $4.1 billion during the periods. The expected increase in minimum required contributions for pension and OPEB costs through 2014 that cannot be funded from cash from operations may need to be funded through external financings. See Note 14 of the Notes to Consolidated Financial Statements for further information regarding Exelon's pension plans and see "Contractual Obligations and Off-Balance Sheet Obligations" within Liquidity and Capital Resources for the expected pension minimum funding requirements, including discretionary contributions necessary to avoid benefit restrictions, for the years 2009-2013.

During 2008, Generation benefited from a provision in the Energy Policy Act of 2005 which allowed companies an income tax deduction for a "special transfer" of funds from a non-tax qualified nuclear decommissioning trust fund to a qualified nuclear decommissioning trust fund. As a result of recent interpretative guidance published by the Internal Revenue Service with respect to this provision in the Energy Policy Act of 2005, Generation completed a special transfer in the first quarter of 2008, which resulted in net positive cash flow of approximately $280 million in total for 2008 and 2009 combined.

In addition, Exelon, through ComEd, has taken certain tax positions to defer the tax gain on the 1999 sale of its fossil generating assets. The ultimate outcome of this matter could result in unfavorable or favorable impacts to Exelon's and ComEd's results of operations, cash flows and financial positions, and such impacts could be material. See Note 11 of the Notes to Consolidated Financial Statements for further information.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the years ending December 31, 2008 and 2007:

	2008	2007	Variance
Net income	$2,737	$2,736	$ 1
Add (subtract):			
Non-cash operating activities [a]	3,400	2,845	555
Pension and non-pension postretirement benefit contributions	(230)	(204)	(26)
Changes in working capital and other noncurrent assets and liabilities [b]	(383)	(365)	(18)
Counterparty collateral, net	1,027	(516)	1,543
Net cash flows provided by operations	$6,551	$4,496	$2,055

(a) Includes depreciation, amortization and accretion, deferred income taxes, provision for uncollectible accounts, equity in earnings of unconsolidated affiliates, pension and other postretirement benefits expense, other decommissioning-related activities, cumulative effect of a change in accounting principle, impairment charges, pension contributions and postretirement healthcare benefit payments and other non-cash items. See Note 19 of the Notes to Consolidated Financial Statements for additional information on non-cash operating activities.

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

Cash flows provided by operations for 2008 and 2007 by Registrant were as follows:

	2008	2007
Exelon	$6,551	$4,496
Generation	4,445	2,994
ComEd	1,079	520
PECO	969	980

Changes in Exelon's, Generation's and ComEd's cash flows from operations were generally consistent with changes in the respective results of operations, as adjusted by changes in working capital in the normal course of business. The significant operating cash flow impacts for Exelon for 2008 and 2007 were as follows:

Exelon

- In 2007, Exelon contributed $50 million to the Exelon Foundation, a nonconsolidated not-for-profit Illinois corporation. The Exelon Foundation was established in the fourth quarter of 2007 to serve educational and environmental philanthropic purposes.
- The Economic Stimulus Act of 2008 was enacted in the first quarter of 2008 and includes an incentive that allows companies to claim an accelerated depreciation deduction for Federal income tax purposes equal to 50% of the cost basis of certain property placed in service during 2008 and to a lesser extent in 2009. Exelon received $248 million in 2008 as a result of this special tax depreciation provision.

Generation

- During 2008, Generation had net collections of counterparty collateral of $1,029 million compared to $(518) million of net disbursements of counterparty collateral in 2007 and $431 million of net collections of counterparty collateral in 2006. The increase in collections was primarily due to changes in market conditions that resulted in an increased mark-to-market asset position. When Generation is in a mark-to-market liability position and is required to post collateral with its counterparties, the collateral may be in various forms, such as cash, 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 $274 million in 2008 and $331 million in 2007.
- Generation received a net cash payment from State Line of approximately $228 million, after adjustments, in consideration for the termination of the State Line PPA and the purchase of coal inventories on hand (and in transit) and other assets.

- During 2008 and 2007, Generation's accounts receivable from ComEd under its supplier forward agreement and its PPA with ComEd, which expired on December 31, 2006, increased (decreased) by $99 million and $(137) million, respectively.
- During 2008 and 2007, Generation's accounts receivable from PECO under its PPA with PECO increased (decreased) by $6 million and $(32) million, respectively.
- During 2008 and 2007, Generation had net payments of approximately $123 million and net receipts of approximately $28 million, respectively, related to option premiums, primarily due to greater hedging activity in 2008 compared to 2007.

ComEd

- As a result of upgraded credit ratings to investment grade, ComEd has been making monthly payments to its energy suppliers, including Generation, under supplier forward contracts since April 2008. Prior to the credit ratings upgrade, ComEd made semi-monthly payments to its energy suppliers. Starting in June 2008, ComEd also began procuring power and renewable energy credits under its request for proposal (RFP) contracts and started to settle the financial swap with Generation. During 2008 and 2007, ComEd's payables to Generation for energy purchases increased (decreased) by $99 million and $(137) million, respectively. During 2008 and 2007, ComEd's payables to other energy suppliers increased by $41 million and $72 million, respectively.
- As part of the 2007 Illinois Settlement and its rate relief programs, ComEd contributed approximately $13 million and $41 million to rate relief programs in 2008 and 2007, respectively. See Note 3 of the Notes to the Consolidated Financial Statements for more information on the rate relief programs.
- As of December 31, 2008 and 2007, ComEd had net over-recovered energy costs and net under-recovered energy costs of $29 million and $97 million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for 2008 and 2007 by registrant were as follows:

	2008	2007
Exelon	$(3,378)	$(2,909)
Generation	(1,967)	(1,424)
ComEd	(958)	(1,015)
PECO	(377)	(337)

Capital expenditures by registrant and business segment for 2008 and projected amounts for 2009 are as follows:

	2008	2009
Generation [(a)]	$1,699	$1,957
ComEd	953	1,000
PECO	392	416
Other [(b)]	73	71
Total Exelon capital expenditures	$3,117	$3,444

(a) Includes nuclear fuel.
(b) Other primarily consists of corporate operations and BSC.

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

Generation. Approximately 46% of the projected 2009 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). Actual 2008 capital expenditures were higher than the projected 2008 capital expenditures previously disclosed in the 2007 Annual Report on Form 10-K as a result of accelerating capital expenditures in 2008 to take advantage of the Economic Stimulus Act of 2008 which provides accelerated tax depreciation benefits for assets purchased and placed in service during the year. Exelon anticipates that Generation's capital expenditures during 2009 will be funded by internally generated funds, borrowings or capital contributions from Exelon.

As discussed in "Executive Overview," Generation has begun the application process that would allow for the possible construction of a new nuclear plant in Texas, and Generation is considering the development of a 600-megawatt combined-cycle natural gas plant in Pennsylvania. While Generation has not made a decision to build these plants, should Generation decide to build these or other plants in the future, substantial additional resources would be required. Such capital projects would have a material impact on the use of Exelon's and Generation's capital resources.

ComEd and PECO. Approximately 51% and 52% of the projected 2009 capital expenditures at ComEd and PECO, respectively, are for continuing projects to maintain and improve the reliability of their respective transmission and distribution systems. The remaining amounts are for capital additions to support new business and customer growth including capacity expansion. ComEd and PECO are each continuing to evaluate their total 2009 capital spending requirements due to the recent decline in economic conditions and projections of load growth, which may reduce total 2009 capital expenditures. ComEd and PECO anticipate that they will fund their capital expenditures during 2009 by internally generated funds and the issuance of debt.

Other significant investing activities for Exelon and Generation for 2008 and 2007 were as follows:

Exelon

- Exelon contributed $9 million and $93 million to its investments in synthetic fuel-producing facilities during 2008 and 2007, respectively.

Generation

- During 2007, Generation received approximately $42 million from Generation's nuclear decommissioning trust funds for reimbursement of expenditures previously incurred for nuclear plant decommissioning activities related to its retired units.
- On February 9, 2007, Tamuin International Inc., 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.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for 2008 and 2007 by registrant were as follows:

	2008	2007
Exelon	$(2,213)	$(1,500)
Generation	(1,470)	(1,571)
ComEd	(161)	547
PECO	(587)	(638)

Debt. Debt activity for 2008 and 2007 by registrant was as follows:

Company	Issuance 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 general corporate purposes.
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 refinance $155 million of trust preferred securities and for general corporate purposes.
ComEd	$91 million tax-exempt variable rate First Mortgage Bonds, Series 2008 F, due March 1, 2017 (a)(b)	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	$50 million tax-exempt variable rate First Mortgage Bonds, Series 2008 D, due March 1, 2020 (a)(b)	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 tax-exempt variable rate First Mortgage Bonds, Series 2008 E, due May 1, 2021 (a)(b)	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, respectively.
PECO	$150 million of First and Refunding Mortgage Bonds, 4.00% due December 1, 2012	Used to refinance First and Refunding Mortgage Bonds, variable auction rate due December 1, 2012.
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.
PECO	$300 million of First and Refunding Mortgage Bonds, 5.60% Series due October 15, 2013	Used to refinance short-term debt.

(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) During the second quarter of 2008, ComEd established a letter of credit facility to provide credit enhancement to variable-rate tax exempt bonds. The new facility and letters of credit issued under the new facility will expire by June 27, 2009.

Company	Issuance of long-term debt in 2007	Use of proceeds
Generation	$700 million of 6.20% Senior Notes, due October 1, 2017	Used to refinance commercial paper and for other general corporate purposes.
Generation	$46 million of Exempt Facilities Revenue Bonds with variable interest rates, due December 1, 2042	Will be used to finance a portion of the construction and installation costs of emissions-control facilities at Keystone Generating Station.
ComEd	$300 million of First Mortgage 5.90% Bonds, Series 103, due March 15, 2036	Used to refinance outstanding commercial paper and to repay a portion of borrowings under ComEd's revolving credit facility.
ComEd	$425 million of First Mortgage 6.15% Bonds, Series 106, due September 15, 2017	Used to repay borrowings made under its revolving credit agreement.
PECO	$175 million of First and Refunding Mortgage Bonds, 5.70% Series due March 15, 2037	Used to supplement working capital previously financed through sales of commercial paper and for other general corporate purposes.

Company	Retirement of long-term debt in 2008
Exelon	$21 million of 6.00-8.00% notes payable for investments in synthetic fuel-producing facilities, due at various dates
Generation	$10 million of 6.33% note payable, due August 8, 2009
Generation	$3 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
ComEd	$295 million of 3.70% First Mortgage Bonds, Series 99, due February 1, 2008
ComEd	$274 million of 5.74% ComEd Transitional Funding Trust, due December 25, 2008
ComEd	$155 million of 8.50% Subordinated Debentures related to ComEd Financing II, due January 15, 2027
ComEd	$120 million of 8.00% First Mortgage Bonds, Series 83, due May 15, 2008
ComEd	$100 million tax-exempt variable auction-rate First Mortgage Bonds, Series 2002, due April 15, 2013 [(a)]
ComEd	$91 million tax-exempt variable auction-rate First Mortgage Bonds, Series 2005, due March 1, 2017 [(a)]
ComEd	$50 million tax-exempt variable auction-rate First Mortgage Bonds, Series 2003 C, due March 1, 2020 [(a)]
ComEd	$42 million tax-exempt variable auction-rate First Mortgage Bonds, Series 2003 B, due November 1, 2019 [(a)]
ComEd	$40 million tax-exempt variable auction-rate First Mortgage Bonds, Series 2003, due May 15, 2017 [(a)]
ComEd	$20 million tax-exempt variable auction-rate First Mortgage Bonds, Series 2003 D, due January 15, 2014 [(a)]
ComEd	$2 million of 3.875-4.75% sinking fund debentures, due at various dates
PECO	$50 million First and Refunding Mortgage Bonds, variable rate, due December 1, 2012 [(b)]
PECO	$50 million First and Refunding Mortgage Bonds, variable rate, due December 1, 2012 [(b)]
PECO	$50 million First and Refunding Mortgage Bonds, variable rate, due December 1, 2012 [(b)]
PECO	$4 million First and Refunding Mortgage Bonds, variable rate, due December 1, 2012
PECO	$450 million of 3.5% First and Refunding Mortgage Bonds, due May 1, 2008
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	$33 million of 7.65% PETT Transition Bonds, due September 1, 2009

(a) First Mortgage bonds issued under the ComEd mortgage indenture that secured variable auction rate tax-exempt pollution control bonds that were refinanced.

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

Company	Retirement of long-term debt in 2007
Exelon	$88 million of 6.00-8.00% notes payable for investments in synthetic fuel-producing facilities, due at various dates
Generation	$10 million of 6.33% note payable, due August 8, 2009
ComEd	$145 million of 7.625% note payable, due January 15, 2007
ComEd	$2 million of 3.875-4.75% sinking fund debentures, due at various dates
PECO	$17 million of variable rate special agreement accounts receivable, due November 2010
ComEd	$138 million of 5.63% ComEd Transitional Funding Trust, due June 25, 2007 [(a)(b)]
ComEd	$236 million of 5.74% ComEd Transitional Funding Trust, due December 25, 2008
PECO	$641 million of 6.13% PETT, due September 1, 2008
PECO	$30 million of 7.625% PETT, due March 1, 2009

(a) Amount includes $17 million previously reflected in prepaid interest. This amount did not impact ComEd's Consolidated Statement of Operations or ComEd's Consolidated Statement of Cash Flows.

(b) ComEd applied $8 million of previously prepaid balances against the long-term debt to ComEd Transitional Funding Trust.

See Note 10 of the Notes to Consolidated Financial Statements for more information on the Registrants' debt.

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 strengthen their respective balance sheets.

Dividends. Cash dividend payments and distributions in 2008 and 2007 by registrant were as follows:

	2008	2007
Exelon	$1,335	$1,180
Generation	1,545	2,357
PECO	484	566

Exelon paid dividends of $330 million, $329 million, $330 million, and $346 million on March 10, 2008, June 10, 2008, September 10, 2008, and December 10, 2008, respectively, to shareholders of record at the close of business on February 15, 2008, May 15, 2008, August 15, 2008, and November 14, 2008, respectively. On January 27, 2009, 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, 2009 to shareholders of record at the end of the day on February 13, 2009. Exelon paid dividends of $296 million, $296 million, $297 million, and $291 million on March 10, 2007, June 11, 2007, September 10, 2007 and December 10, 2007, respectively, to shareholders of record at the close of business on February 15, 2007, May 15, 2007, August 15, 2007 and November 15, 2007, respectively.

During 2008 and 2007, ComEd did not pay any dividend to manage cash flows and its capital structure. On January 26, 2009, the ComEd board declared a dividend of $0.472 per share on its common stock. ComEd's Board of Directors will continue to assess ComEd's ability to pay a dividend in future periods.

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. During 2007, Exelon purchased $37 million of common stock under Exelon's 2004 share repurchase program and $1.25 billion of common stock under Exelon's 2007 accelerated share repurchase program, including the impact of the settlement of forward contracts indexed to Exelon's own common stock.

On September 2, 2008, Exelon's Board of Directors approved a share repurchase program for up to $1.5 billion of Exelon's outstanding common stock. Exelon management has 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, including possible acquisitions such as the proposed acquisition of NRG Energy, Inc. See Note 16 of the Notes to Consolidated Financial Statements for additional information.

Intercompany Money Pool. Generation's net borrowings from the Exelon Corporate intercompany money pool did not change during 2008 and 2007. PECO's net borrowings from the Exelon Corporate intercompany money pool did not change during 2008. PECO's net borrowings from the Exelon Corporate intercompany money pool decreased $45 million in 2007.

Short-Term Borrowings. During 2008, Exelon and PECO repaid $95 million and $151 million, net, of commercial paper, respectively. During 2008, ComEd repaid $310 million of outstanding borrowings under ComEd's credit agreement. During 2007, Exelon, ComEd and PECO (repaid) issued $(59) million, $(60) million and $151 million, net, of commercial paper, respectively. During 2007, ComEd issued $370 million of short-term borrowings under ComEd's credit agreement.

Retirement of Long-Term Debt to Financing Affiliates. Retirement of long-term debt to financing affiliates during 2008 and 2007 by registrant were as follows:

	Year Ended December 31,	
	2008	2007
Exelon	$1,038	$1,020
ComEd	429	349
PECO	609	671

Contributions from Parent/Member. Contributions from Parent/Member (Exelon) for the years ended December 31, 2008 and 2007 by registrant were as follows:

	Year Ended December 31,	
	2008	2007
Generation	$ 86	$ 54
ComEd	14	28
PECO [(a)]	320	338

(a) $284 million and $306 million for the twelve months ended December 31, 2008 and 2007, respectively, reflect payments received to reduce the parent receivable.

Other. Other significant financing activities for Exelon for the year ended December 31, 2008 and 2007 were as follows:

- Exelon received proceeds from employee stock plans of $130 million and $215 million during 2008 and 2007, respectively.
- Exelon's other financing activities during 2008 and 2007 include $60 million and $97 million, respectively, of excess tax benefits, which represent the tax deduction in excess of the tax benefit related to compensation cost recognized for stock options exercised.

Credit Matters

Recent Market Conditions

The Registrants believe they have sufficient liquidity despite the current disruption of the capital and credit markets. The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flow from continuing operations, public debt offerings, commercial paper markets and a large, diversified credit facility ($7.3 billion in aggregate total commitments and $6.9 billion available as of December 31, 2008, of which no financial institution, assuming announced consolidations, has more than 10% of the aggregate commitments for Exelon, Generation and PECO and 12% for ComEd). Select Registrants also have additional letter of credit facilities used solely to enhance tax-exempt variable rate debt. Certain of these letters of credit will expire in 2009 ($311 million and $194 million at Generation and ComEd, respectively), which the Registrants plan to extend or substitute. While Exelon, Generation and PECO accessed the commercial paper market intermittently in 2008, they were able to fund their short-term liquidity needs with commercial paper, when necessary. Although the overall cost of issuing commercial paper was lower in the fourth quarter of 2008 due to recent Federal Reserve Bank actions and guarantee programs, credit spreads during 2008 generally widened based on the applicable London Interbank Offered Rate (LIBOR) rate and the actual interest rates on commercial paper issued by Exelon, Generation and PECO. ComEd has been utilizing its credit facility to fund its short-term liquidity needs. The Registrants routinely review liquidity sufficiency, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements and the impacts of hypothetical credit downgrades. As the national and world-wide financial crisis has worsened in recent months, the Registrants have continued to closely monitor events 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 2008 Form 10-K for further information regarding the effects of a longer-term disruption in the capital and credit markets or significant bank failures.

If Generation and ComEd lost their investment grade credit rating as of December 31, 2008, they would have been required to provide incremental collateral of approximately $830 million and $282 million, respectively, which is well within their current available credit facility capacities of approximately $4.7 billion and $751 million, respectively. On October 21, 2008, Standard and Poor's Corporation downgraded PECO's corporate credit rating to BBB from BBB+. Subsequently, PECO provided PJM $90 million in collateral in the form of a letter of credit. If PECO were to have lost its investment grade credit rating as of December 31, 2008, it would have been required to provide collateral of an additional $20 million in accordance with PJM's credit policy and could have been required to provide collateral of approximately $135 million related to its natural gas procurement contracts, which is well within PECO's current available credit facility capacity of $481 million.

On September 15, 2008, Lehman Brothers Holdings Inc. (Lehman) filed for protection under Chapter 11 of the Federal Bankruptcy Code in the United States Bankruptcy Court in the Southern District of New York. Exelon, Generation, ComEd, and PECO have or had various business relationships with subsidiaries of Lehman. The Registrants no longer have any credit facility commitments with Lehman as of September 30, 2008. Generation is a counterparty with Lehman Brothers Commodity Services Inc., a subsidiary of

Lehman, in wholesale energy marketing transactions. The obligations of Lehman Brothers Commodity Services Inc. are guaranteed by Lehman, and as a result of the Lehman bankruptcy, Generation exercised its right to terminate its forward contract with Lehman Brothers Commodity Services, Inc. As of December 31, 2008, Exelon and Generation's direct net exposure to Lehman Brothers Commodity Services Inc., based on Generation's wholesale energy marketing business and market prices, was $22 million pre-tax, which was fully reserved through a charge to the statement of operations during the year ended December 31, 2008.

Exelon Credit Facilities

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, and ComEd meets its short-term liquidity requirements primarily through borrowings under its credit facility. While short-term borrowing costs have not been significant to date, further disruptions in the credit markets may result in increased costs for commercial paper borrowings. Continued disruptions in the credit markets could limit the ability of the Registrants to issue commercial paper, which may increase their reliance on their respective revolving credit facilities for short-term liquidity purposes. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. See Note 10 of the Notes to the Consolidated Financial Statements for further information regarding the Registrants' credit facilities.

At December 31, 2008, the Registrants had the following aggregate bank commitments and available capacity under the credit agreements and the indicated amounts of outstanding commercial paper:

Borrower	Aggregate Bank Commitment [a]	Outstanding Commercial Paper	Outstanding Letters of Credit	Available Capacity under Revolving Credit Agreements [b]
Exelon Corporate	$ 957	$ 56	$ 5	$ 952
Generation	4,834	—	127	4,707
ComEd	952	—	141	751
PECO	574	95	93	481

(a) Represents the total bank commitments to the borrower under credit agreements to which the borrower is a party.

(b) Available capacity represents the unused bank commitments under the borrower's credit agreements net of outstanding letters of credit and credit facility draws. The amount of commercial paper outstanding does not reduce the available capacity under the credit agreements.

Interest rates on advances under the credit facilities are based on either prime or the LIBOR plus an adder based on the credit rating of the borrower as well as the total outstanding amounts under the agreement at the time of borrowing. In the cases of Exelon, Generation and PECO, the maximum LIBOR adder is 65 basis points; and in the case of ComEd, it is 162.5 basis points for the unsecured facility.

The average interest rates on short-term debt (facility borrowings and commercial paper) for 2008 for Exelon, Generation, ComEd and PECO were approximately 3.22%, 3.13%, 3.91% and 3.22%, respectively.

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 interest coverage ratios exclude revenues and interest expenses attributable to securitization debt, certain changes in working capital, distributions on preferred securities of subsidiaries and interest on nonrecourse debt. The following table summarizes the minimum thresholds reflected in the credit agreements for the year ended December 31, 2008:

	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, 2008, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO
Interest coverage ratio	12.20	28.44	3.83	6.15

An event of default under any of the Registrants' credit facilities will 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 $100,000,000 in the aggregate by Generation under its credit facility will constitute an event of default under the Exelon credit facility.

Security Ratings

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets depend on the securities ratings of the entity that is accessing the capital markets. The following table shows the Registrants' securities ratings at December 31, 2008:

	Securities	Moody's Investors Service	Standard & Poor's Corporation	Fitch Ratings.
Exelon Corporate	Senior unsecured debt	Baa1	BBB-	BBB+
	Commercial paper	P2	A2	F2
Generation	Senior unsecured debt	A3	BBB	BBB+
	Commercial paper	P2	A2	F2
ComEd	Senior unsecured debt	Baa3	BBB-	BBB-
	Senior secured debt	Baa2	BBB+	BBB
	Commercial paper	P3	A3	B
PECO	Senior unsecured debt	A3	BBB	A-
	Senior secured debt	A2	A-	A
	Commercial paper	P1	A2	F2
	Transition bonds [(a)]	Aaa	AAA	AAA

(a) Issued by PETT, an unconsolidated affiliate of PECO.

On March 19, 2008, S&P upgraded ComEd's long-term unsecured security ratings from B+ to BBB- as a result of a change in methodology by S&P. On September 11, 2008, S&P upgraded ComEd's corporate rating from BB to BBB- and upgraded its long-term, secured security ratings from BBB to BBB+ to reflect the improving regulatory environment in Illinois. S&P also increased ComEd's commercial paper rating to A3 from B.

On October 3, 2008, Moody's Investors Service (Moody's) upgraded the long-term senior unsecured rating of ComEd to "Baa3" from "Ba1" and the commercial paper rating to "Prime-3" from "Not Prime". ComEd's senior secured rating of "Baa2" remains unchanged, and ComEd's rating outlook is stable. A Moody's press release indicated that "the upgrade largely reflects our assessment of the distribution rate case decision" and "also factors in the improved financial flexibility that exists at ComEd as the first mortgage collateral, which had previously secured the company's $1 billion revolving credit facility was released and replaced by a similar sized unsecured revolving credit facility."

On October 21, 2008, S&P lowered its corporate credit rating on Exelon Corporate, Generation and PECO to BBB from BBB+. S&P lowered the senior unsecured ratings of Exelon Corporate to BBB- from BBB and of Generation to BBB from BBB+. The senior secured rating of PECO was lowered to A- from A. In addition, the ratings of Exelon Corporate and all of its subsidiaries, including ComEd, were placed on CreditWatch with a negative outlook. S&P indicated concerns about Exelon's potential credit position related to the proposed offer to acquire NRG. The short-term commercial paper ratings of Exelon Corporate and all of its subsidiaries were affirmed by S&P. This downgrade triggered a reduction in PECO's unsecured credit limit in accordance with PJM's credit policy. PECO issued a letter of credit to PJM for $90 million to restore the amount of its unsecured credit. Generation was not required to provide collateral as a result of this downgrade. No collateral requirements of Exelon and ComEd were impacted by this downgrade.

On October 21, 2008, Fitch Ratings, Ltd. placed Exelon and Generation on Rating Watch Negative following the announcement of the proposed offer for NRG.

On November 12, 2008, Moody's Investors Service placed the ratings of Exelon, Generation and PECO under review for possible downgrade. In addition, S&P placed the short-term ratings of Exelon, Generation and PECO on CreditWatch with negative implications. These actions were taken after Exelon commenced the exchange offer for NRG's shares.

The terms of the financial swap contract between Generation and ComEd provide that: (1) if ComEd is upgraded to investment grade by Moody's Investor Service or S&P and then is later downgraded below investment grade, or (2) if Generation is downgraded below investment grade by Moody's Investor Service or S&P, collateral postings would be required by the applicable party depending on how market prices compare to the contracted price levels. As previously noted above, ComEd was upgraded to investment grade by S&P, and, therefore, the aforementioned condition has been satisfied such that if ComEd is later downgraded, it could be subject to margining depending on market prices at that time. However, under no circumstances would collateral postings exceed $200 million from either ComEd or Generation under the swap contract.

Exelon or any of the Registrants might experience a downgrade in its credit ratings by one or more notches if the transaction with NRG is completed. Exelon remains committed to investment grade ratings and is committed that the NRG transaction will not cause Exelon or its subsidiaries to go below investment grade for senior unsecured debt. Potential measures to protect investment grade ratings include issuing additional equity, sale of assets, or reducing dividend payments or other discretionary uses of cash.

None of the Registrants' borrowings is subject to default or prepayment as a result of a downgrading of securities although such a downgrading could increase fees and interest charges under the Registrants' credit facilities.

A security rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency.

Variable-Rate Debt

As of December 31, 2008, Generation had $566 million outstanding in tax-exempt variable rate debt, of which $520 million is credit enhanced by letters of credit and $46 million is unenhanced. The $46 million of unenhanced bonds remarket during the first quarter, where there may or may not be buyers willing to purchase the securities. If the securities fail to remarket, Generation has the option to hold the bonds for a period of time and wait until there are willing buyers. Generation also has the option to issue a letter of credit to credit enhance the bonds for the variable rate mode, or Generation has the option to change to another mode, including put bonds or fixed rate to maturity.

For the $520 million in tax-exempt variable rate debt that is backed by letters of credit, $307 million in principal of letters of credit expire during the third quarter of 2009. Generation anticipates renewing the letters of credit with existing banks or entering into letters of credit with new banks. If letters of credit are not available or are not economical, Generation will be prepared to hold the bonds for a period of time or change the bonds to another interest rate mode, including put bonds or fixed rate to maturity. Generation believes that the final results of the unenhanced debt, the letters of credit or possible mode changes will not be material. The remaining $213 million in principal of tax-exempt variable rate debt Generation has letters of credit that expire during the second quarter of 2010.

As of December 31, 2008, ComEd had $191 million outstanding in tax-exempt variable rate debt that is credit enhanced by letters of credit and expire during the second quarter of 2009. ComEd anticipates renewing the letters of credit with existing banks, or entering into letters of credit with new banks. If letters of credit are not available or are not economical, ComEd will be prepared to hold the bonds for a period of time or change the bonds to another interest rate mode, including put bonds or fixed rate to maturity. ComEd believes the final results of the letters of credit or possible mode changes will not be material.

As of January 1, 2008, PECO had $154 million of tax-exempt variable auction rate securities outstanding. On March 5, 2008, PECO issued $150 million of 4% fixed rate tax-exempt First and Refunding Mortgage Bonds, due December 1, 2012, to refinance three series of outstanding variable auction-rate, tax-exempt bonds. On May 1, 2008, PECO used available cash and redeemed its remaining $4.2 million of tax-exempt variable auction rate bonds.

Investments in Nuclear Decommissioning Trust Funds

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the values 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 allocations in accordance with Generation's nuclear decommissioning trust fund investment policy. With regards to equity securities, Generation's investment policy establishes limits on the concentration of equity holdings in any one company and also in any one industry. With regards to its fixed-income

securities, Generation's investment policy limits the concentrations of the types of bonds that may be purchased for the trust funds and also requires a minimum percentage of the portfolio to have investment grade ratings (minimum credit quality ratings of "Baa3" by Moody's Investor Service, "BBB-" by S&P and "BBB-" by Fitch Ratings) while requiring that the overall portfolio maintain a minimum credit quality rating of "A2". See "Executive Overview" for further information regarding the trust funds and the NRC's minimum funding requirements and related liquidity ramifications.

Other Credit Matters

Capital Structure

At December 31, 2008, the capital structures of the Registrants consisted of the following:

	Exelon Consolidated	Generation	ComEd	PECO [a]
Long-term debt	47%	28%	40%	35%
Long-term debt to affiliates [b]	6	—	2	23
Common equity	46	—	57	39
Member's equity	—	72	—	—
Preferred securities	—	—	—	1
Commercial paper and notes payable	1	—	1	2

(a) As of December 31, 2008, PECO's capital structure, excluding the impacts of the deduction from shareholders' equity of the $500 million receivable from Exelon (which amount is deducted for GAAP purposes as reflected in the table above) would consist of 44% common equity, 1% preferred securities, 2% notes payable and 53% long-term debt, including long-term debt to unconsolidated affiliates.

(b) Includes approximately $1.5 billion, $200 million and $1.3 billion owed to unconsolidated affiliates of Exelon, ComEd and PECO, respectively, that qualify as special purpose entities under FIN 46-R. These special purpose entities were created for the sole purposes of issuing transition bonds to securitize intangible transition property consisting of CTCs of PECO or mandatorily redeemable trust preferred securities of ComEd and PECO. See Note 1 of the Notes to Consolidated Financial Statements for additional information regarding FIN 46-R.

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 2008 are described in the following table in addition to the net contribution or borrowing as of December 31, 2008:

	Maximum Contributed	Maximum Borrowed	December 31, 2008 Contributed (Borrowed)
Generation	$288	$328	$—
PECO	328	405	—
BSC	6	92	—
Exelon	183	—	—

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, 2008, the Registrants 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, the current financial condition of the company, its securities ratings and market conditions.

Regulatory Authorizations

The issuance by ComEd of long-term debt or equity securities requires the prior authorization of the ICC. The issuance by PECO of long-term debt or equity securities requires the prior authorization of the PAPUC. 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, 2008, ComEd had $389 million in long-term debt refinancing authority from the ICC and $399 million in new money long-term debt financing authority. As of December 31, 2008, PECO had $975 million in long-term debt financing authority from the PAPUC expiring in May 2009. PECO plans to seek additional authority from the PAPUC during the first or second quarter of 2009.

FERC has financing jurisdiction over ComEd's and PECO's short-term financings and all of Generation's financings. As of December 31, 2008, ComEd and PECO had short-term financing authority from the FERC that expire on December 31, 2009 of $2.5 billion and $1.5 billion, respectively. Generation currently has blanket financing authority that it received from FERC with its market-based rate authority. See Note 3 of the 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, 2008, Exelon had retained earnings of $6.8 billion, including Generation's undistributed earnings of $2,323 million, ComEd's retained earnings of $170 million consisting of an unappropriated retained deficit of $1,639 million partially offset by $1,809 million of retained earnings appropriated for future dividends, and PECO's retained earnings of $389 million. See Note 18 of the Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Investments in Synthetic Fuel-Producing Facilities

Exelon, through three separate wholly owned subsidiaries, owns interests in two limited liability companies and one limited partnership that own synthetic fuel-producing facilities. Prior to December 31, 2007, Section 45K (formerly Section 29) of the Internal Revenue Code provided tax credits for the sale of synthetic fuel produced from coal. The ability to earn these synthetic fuel tax credits expired on December 31, 2007 and, as such, the synthetic fuel-producing facilities that Exelon had interests in ceased operations on or before December 31, 2007.

In March 2008, the Internal Revenue Service (IRS) published the 2007 oil Reference Price which resulted in a 67% phase-out of tax credits for calendar year 2007 that reduced Exelon's earned after-tax credits of $258 million to $85 million for the year ended December 31, 2007. Exelon generated approximately $220 million of cash over the life of these investments. As a result of the phase-out of tax credits in 2007 and the timing of the realization of tax benefits earned in prior years, Exelon collected approximately $200 million of cash in 2008, which includes $44 million collected in the first quarter of 2008 related to the settlement of derivatives that were entered into in the normal course of trading operations in 2005 to economically hedge a portion of the exposure to a phase-out of the tax credits.

Contractual Obligations and Off-Balance Sheet Arrangements

The following table summarizes Exelon's future estimated cash payments under existing contractual obligations, including payments due by period.

		Payment due within				
	Total	2009	2010-2011	2012-2013	Due 2014 and beyond	All Other
Long-term debt	$11,407	$ 27	$2,410	$1,377	$ 7,593	$ —
Long-term debt to financing trusts	1,514	319	805	—	390	—
Interest payments on long-term debt [a]	6,770	627	1,160	881	4,102	—
Interest payments on long-term debt to financing trusts [a]	675	94	72	50	459	—
FIN 48 liability and interest [b]	446	5	—	—	—	441
Capital leases	40	2	5	4	29	—
Operating leases	762	68	124	117	453	—
Purchase power obligations [c]	3,568	526	708	543	1,791	—
Fuel purchase agreements	6,504	1,325	1,774	1,185	2,220	—
Other purchase obligations [d]	1,076	333	420	268	55	—
City of Chicago agreement—2003 [e]	24	6	12	6	—	—
Spent nuclear fuel obligation	1,015	—	—	—	1,015	—
Pension minimum funding requirement [f]	4,011	162	1,647	1,538	664	—
Other postretirement benefits minimum funding requirement [g]	256	56	98	102	—	—
Total contractual obligations	$38,068	$3,550	$9,235	$6,071	$18,771	$441

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2008 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, 2008.

(b) As of December 31, 2008, Exelon's FIN 48 liability and FIN 48 net interest payable were $430 million and $16 million, respectively. Exelon was unable to reasonably estimate the timing of FIN 48 liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.

(c) Net capacity purchases include tolling agreements and other capacity contracts that are accounted for as operating leases. Amounts presented in the tables represent Generation's expected payments under these arrangements at December 31, 2008. 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 supplier forward contracts as these contracts do not require purchases of fixed or minimum quantities. See Notes 3 and 18 of the Notes to Consolidated Financial Statements.

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

(e) In 2003, ComEd entered into separate agreements with the City of Chicago and with Midwest Generation. Under the terms of the agreement with the City of Chicago, 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.

(f) These amounts represent Exelon's estimated minimum pension contributions required under ERISA and the Pension Protection Act of 2006 as well as discretionary contributions necessary to avoid benefit restrictions. These amounts represent estimates that are based on assumptions that are subject to change. As further described in "Cash Flows From Operating Activities" above, WRERA clarified that asset smoothing is permitted in accordance with the Pension Protection Act of 2006. Exelon has not yet determined whether it will elect this option. If Exelon elected this option, the total contributions in the table above would be $162 million, $832 million, $2,563 million and $578 million in 2009, 2010-2011, 2012-2013 and 2014, respectively. The minimum required contributions for years after 2014 are currently not reliably estimable. Exelon may choose to make additional discretionary contributions.

(g) These amounts represent estimated minimum other postretirement benefit contributions required under a PAPUC rate order. These minimum contributions represent estimates that are based on assumptions that are subject to change. The minimum required contribution for years after 2014 are currently not reliably estimable. Exelon may contribute more than the minimum funding requirements; however, these amounts are not included above as such amounts are discretionary.

Exelon's commitments as of December 31, 2008, representing commitments potentially triggered by future events, were as follows:

	Expiration within				
	Total	2009	2010-2011	2012-2013	2014 and beyond
Letters of credit (non-debt) [a]	$ 430	$ 430	$ —	$ —	$ —
Letters of credit (long-term debt)—interest coverage [b]	18	7	11	—	—
Surety bonds [c]	88	7	—	—	81
Performance guarantees [d]	296	200	—	95	1
Energy marketing contract guarantees [e]	207	162	40	—	5
Nuclear insurance premiums [f]	1,997	—	—	—	1,997
Lease guarantees [g]	131	—	3	9	119
2007 City of Chicago Settlement [h]	14	8	4	2	—
Midwest Generation Capacity Reservation Agreement guarantee [i]	14	4	8	2	—
Rate relief commitments – settlement legislation [j]	152	128	24	—	—
Construction commitments [k]	341	123	135	83	—
Total commitments	$3,688	$1,069	$225	$191	$2,203

(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, 2008, Exelon had $225 million of outstanding letters of credit (non-debt) issued under its $6.6 billion credit agreements. Guarantees of $10 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 $566 million at Generation and $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 execution under specific contracts.

(e) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts.

(f) Nuclear insurance premiums—Represent 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.

(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 $18 million and $23 million was paid in December 2008 and 2007, respectively. See Note 3 of the Notes to Consolidated Financial Statements for additional details on the 2007 City of Chicago Settlement.

(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. Under FIN 45, $1 million is included as a liability on Exelon's Consolidated Balance Sheets at December 31, 2008 related to this guarantee.

(j) See Notes 3 and 18 of the Notes to Consolidated Financial Statements for additional detail on Generation's and ComEd's rate relief commitments.

(k) See Note 18 of the Notes to Consolidated Financial Statements for additional detail on ComEd's and PECO's construction commitments.

For additional information regarding:

- commercial paper, see Note 10 of the Notes to Consolidated Financial Statements.
- long-term debt, see Note 10 of the Notes to Consolidated Financial Statements.
- FIN 48 liabilities, see Note 11 of the Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 10 of the Notes to Consolidated Financial Statements.
- operating leases, energy commitments, fuel purchase agreements, construction commitments and rate relief commitments, see Note 18 of the Notes to Consolidated Financial Statements.

- the nuclear decommissioning and spent nuclear fuel obligations, see Notes 12 and 13 of the Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 3 of the Notes to Consolidated Financial Statements.

Variable Interest Entities

Generation PPAs. Generation enters into power purchase agreements (PPAs) with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to customers, including ComEd and PECO, and these PPAs are not consolidated in Exelon's and Generation's financial statements pursuant to the provisions of FASB Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities" (FIN 46-R). See Note 1 of the Notes to Consolidated Financial Statements for further information.

Financing Trusts of ComEd and PECO. The financing trusts of ComEd, namely ComEd Financing II, ComEd Financing III, ComEd Funding LLC and ComEd Transitional Funding Trust, and the financing trusts of PECO, namely PECO Trust III, PECO Trust IV and PETT, are not consolidated in Exelon's, ComEd's and PECO's financial statements pursuant to the provisions of FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" and FIN 46 (revised December 2003) (FIN 46-R). Amounts of approximately $200 million and $1.3 billion, respectively, owed by ComEd and PECO to these financing trusts were recorded as long-term debt to financing trusts and PETT within the Consolidated Balance Sheets as of December 31, 2008. During 2008, ComEd Financing II, ComEd Funding LLC and ComEd Transitional Funding Trust were liquidated upon final payment of the outstanding debt of each entity. See Note 1 of the Notes to Consolidated Financial Statements for further information.

Nuclear Insurance Coverage

Generation carries property damage, decontamination and premature decommissioning insurance for each station loss resulting from damage to Generation's nuclear plants, subject to certain exceptions. Additionally, Generation carries business interruption insurance in the event of a major accidental outage at a nuclear station. Finally, Generation participates in the Master Worker Program, which provides coverage for worker tort claims filed for bodily injury caused by a nuclear energy accident. See Note 18 of the Notes to Consolidated Financial Statements for additional discussion of nuclear insurance. For its types of insured losses, 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.

PECO 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 PECO accounted for as a sale under SFAS, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities—a Replacement of FASB Statement no. 125," (SFAS No. 140). PECO retains the servicing responsibility for the sold receivables and has recorded a servicing liability in accordance with FASB Statement No. 156, "Accounting for Servicing of Financial Assets, an amendment of FASB Statement No. 140." The agreement terminates on September 18, 2009 unless extended in accordance with its terms. As of December 31, 2008, PECO is in compliance with the requirements of the agreement. See Note 16—Fair Value of Financial Assets and Liabilities for additional information regarding the servicing liability.

New Accounting Pronouncements

See Note 1 of the Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

In November 2008, the SEC issued a roadmap for the potential use of International Financial Reporting Standards (IFRS) in the U.S. IFRS is a set of accounting standards developed by the International Accounting Standards Board, whose mission is to develop a single set of global financial reporting standards for general purpose financial statements. The roadmap indicates that the SEC will reconvene in 2011 to evaluate progress towards certain identified milestones and decide whether a mandatory IFRS conversion should be required for all U.S. issuers beginning with large accelerated filers in 2014. Exelon is currently evaluating the potential impact IFRS may have on its 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 Risk Management Committee (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

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. Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather, governmental regulatory and environmental policies, and other factors. Exelon seeks to mitigate its commodity price risk through the purchase and sale of electric capacity, energy and fossil fuels including oil, gas, coal and emission allowances. Within Exelon, Generation has the most exposure to commodity price risk. PECO has transferred all of its electricity commodity price risk to Generation through a purchase power agreement (PPA) that expires at the end of 2010. PECO relies on the PAPUC's purchased gas cost clause to mitigate natural gas price risk associated with market variability, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. ComEd has transferred most of its near term commodity price risk to generating companies through the former Illinois auction process and the significant portion of its longer term commodity price risk to Generation through the five-year financial swap contract that expires on May 31, 2013.The Illinois Settlement Legislation provides for the pass-through of procurement costs by ComEd to its customers.

Exelon

In 2005, Exelon entered into certain derivatives in the normal course of trading operations to economically hedge a portion of the exposure to a phase-out of the tax credits for the sale of synthetic fuel produced from coal. Including the related mark-to-market gains and losses on these derivatives, interests in synthetic fuel-producing facilities did not have any net impact on Exelon's net income for the year ended December 31, 2008, and increased (reduced) Exelon's net income by $87 million and $(24) million during the years ended December 31, 2007 and 2006, respectively. Net income or net losses from interests in synthetic fuel-producing facilities are reflected in Exelon's Consolidated Statements of Operations within income taxes, operating and maintenance expense, depreciation and amortization expense, interest expense, equity in losses of unconsolidated affiliates and other, net. See Note 11 of the Notes to consolidated Financial Statements for additional information regarding synthetic fuel activity.

Generation

Generation's energy contracts are accounted for under SFAS No. 133. Economic hedges may qualify for the normal purchases and normal sales exemption to SFAS No. 133, which is discussed in Critical Accounting Policies and Estimates. Economic hedges that do not qualify for the normal purchases and normal sales exception are recorded as assets or liabilities on the balance sheet at fair value. Changes in the derivatives recorded at fair value are recognized in results of operations unless specific hedge accounting criteria are met and the derivatives are designated as cash-flow hedges, in which case changes in fair value are recorded in other comprehensive income (OCI), and gains and losses are recognized in results of operations when the underlying transaction occurs. Changes in the fair value of derivative contracts that do not meet the hedge criteria under SFAS No. 133 or are not designated as such are recognized in current results of operations.

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 has hedges in place for 2009 and 2010 and, with the ComEd financial swap contract, also for 2011 into 2013.

The economic hedge activity resulted in a net mark to market energy contract asset position of $1,151 million at December 31, 2008, comprised of a net energy contract asset for cash flow hedges of $1,197 million and a net energy contract liability for other derivatives of $46 million. The net mark to market asset position for the portfolio at December 31, 2008 is a result of forward market prices decreasing relative to the contracted price of the derivative instruments, the majority of which are hedges of future power

sales. Activity associated with the cash flow hedges are recognized through accumulated OCI until the period in which the associated physical sale of power occurs. At that time, the cash flow hedge's mark-to-market position is reversed and reclassified as results of operations, which when combined with the impacts of the actual physical power sale, results in the ultimate recognition of net revenues at the contracted price.

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 has estimated greater than 95% and 90% for economic and cash flow hedge ratios for 2009 and 2010, respectively, which includes cash flow and other derivatives, for its energy marketing portfolio. This financial hedge ratio is Generation's estimate of the gross margin that is hedged given the current assessment of market volatility. ComEd's and PECO's retail load assumptions are based on forecasted average demand.

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. The hedge ratio is not fixed and will vary from time to time depending upon market conditions, demand, energy market option volatility and actual loads. During peak periods, Generation's amount hedged declines to meet its energy and capacity commitments to ComEd and PECO. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price exposure for Generation's unhedged positions in its non-trading portfolio associated with a 10% reduction in the annual average around-the-clock market price of electricity would be a decrease in pre-tax net income of less than $75 million and $150 million, respectively, for 2009 and 2010. This sensitivity assumes that price changes occur evenly throughout the year and across all markets. The sensitivity also assumes a static portfolio. Generation expects to actively manage its portfolio to mitigate market price 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 uses financial contracts for proprietary trading purposes. Proprietary trading includes all contracts entered into purely to profit from market price changes as opposed to hedging an exposure. These activities are accounted for on a mark-to-market basis. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a very small portion of Generation's overall energy marketing activities. For example, the limit on open positions in electricity for any forward month represents less than one percent of Generation's owned and contracted supply of electricity. Generation expects this level of proprietary trading activity to continue in the future. The proprietary trading activities included volumes of 8,891 GWhs, 20,323 GWhs and 31,692 GWhs for the years ended December 31, 2008, 2007 and 2006, respectively. Trading portfolio activity for the year ended December 31, 2008 resulted in pre-tax gains of $106 million due to net mark-to-market gains of $63 million and realized gains of $43 million. Generation uses a 95% confidence interval, one day holding period, one-tailed statistical measure in calculating its Value-at-Risk (VaR). The daily VaR on proprietary trading activity averaged $300,000 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, 2008 of $7,182 million, Generation has not segregated proprietary trading activity in the following tables. The trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop-loss and VaR limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's Risk Management Committee monitor the financial risks of the proprietary trading activities.

ComEd

ComEd's energy contracts are accounted for under SFAS No. 133. Economic hedges may qualify for the normal purchases and normal sales exemption to SFAS No. 133. Energy contracts that do not qualify for the normal purchases and normal sales exception are recorded as assets or liabilities on the balance sheet at fair value. Changes in the derivatives recorded at fair value are recognized in results of operations unless specific hedge accounting criteria are met and the derivatives are designated as cash-flow hedges, in which case changes in fair value are recorded in OCI, and gains and losses are recognized in results of operations when the underlying transaction occurs or if regulatory accounting criteria are met. With the exception of ComEd's energy derivative swap with Generation, changes in the fair value of derivative contracts that do not meet the hedge criteria under SFAS No. 133 or are not designated as such are recognized in current results of operations. Since the swap contract 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 the fair value each period is recorded by ComEd as 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 to SFAS No. 133. ComEd does not enter into derivatives for speculative or trading purposes. See Note 9 of the Notes to Consolidated Financial Statements for additional information regarding derivatives.

PECO

PECO has entered into derivative natural gas contracts to hedge its long-term price risk in the natural gas market. All of PECO's natural gas supply agreements that are derivatives qualify for the normal purchases and normal sales exception to SFAS No. 133. In addition, Generation and PECO have entered into a long-term full-requirements power purchase agreement (PPA) under which PECO obtains all of its electric supply from Generation through 2010. The PPA is not considered a derivative under SFAS No. 133.

Trading and Non-Trading Marketing Activities. The following detailed presentation of Exelon's, Generation's and ComEd'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 and ComEd's mark-to-market net asset or liability balance sheet position from January 1, 2007 to December 31, 2008. 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.

	Generation	ComEd	Intercompany Eliminations [e]	Exelon
Total mark-to-market energy contract net assets (liabilities) at January 1, 2007 [a]	$ 252	$ (11)	$ —	$ 241
Total change in fair value during 2007 of contracts recorded in result of operations	(29)	—	—	(29)
Reclassification to realized at settlement of contracts recorded in results of operations	(106)	4	—	(102)
Reclassification to realized at settlement from accumulated OCI	(15)	3	—	(12)
Effective portion of changes in fair value—recorded in OCI [c]	(1,310)	4	456	(850)
Changes in fair value—energy derivative with Generation [d]	—	456	(456)	—
Changes in collateral	519	—	—	519
Other balance sheet reclassifications	(1)	—	—	(1)
Total mark-to-market energy contract net assets (liabilities) at December 31, 2007 [a]	$ (690)	456	—	$ (234)
Total change in fair value during 2008 of contracts recorded in result of operations	646	—	—	646
Reclassification to realized at settlement of contracts recorded in results of operations	(131)	—	—	(131)
Reclassification to realized at settlement from accumulated OCI [b]	544	—	(24)	520
Effective portion of changes in fair value—recorded in OCI [c]	1,784	—	(888)	896
Changes in fair value—energy derivative with Generation [d]		(912)	912	—
Changes in collateral	(1,024)	—	—	(1,024)
Other balance sheet reclassifications	(11)	—	—	(11)
Total mark-to-market energy contract net assets (liabilities) at December 31, 2008 [a]	$ 1,118	$(456)	$ —	$ 662

(a) Amounts are shown net of collateral paid to and received from counterparties in accordance with FSP FIN 39-1.

(b) For Generation, includes $24 million gain of reclassifications from accumulated OCI to net income for the year ended December 31, 2008 related to the settlement of the five-year financial swap contract with ComEd.

(c) For Generation, includes $888 million gain and $456 million loss of changes in fair value of the five-year financial swap with ComEd for the years ended December 31, 2008 and 2007, respectively.

(d) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2008, ComEd recorded a $456 million regulatory asset related to its mark-to-market derivative liability. As of December 31, 2007 ComEd recorded a $456 million regulatory liability related to its mark-to-market derivative asset. In addition, ComEd included a net reduction of purchased power expense of $2 million related to changes in fair value of the five-year swap contract with Generation for the year ended December 31, 2008. No effect to purchased power expense was recorded for the year ended December 31, 2007.

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

The following tables detail the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2008 and 2007:

	December 31, 2008			
	Generation [a][b]	ComEd [a]	Intercompany Elimination [c]	Exelon
Current assets	$ 521	$ —	$(111)	$ 410
Noncurrent assets	835	—	(345)	490
Total mark-to-market energy contract assets	1,356	—	(456)	900
Current liabilities	(214)	(111)	111	(214)
Noncurrent liabilities	(24)	(345)	345	(24)
Total mark-to-market energy contract liabilities	(238)	(456)	456	(238)
Total mark-to-market energy contract net assets (liabilities)	$1,118	$(456)	$ —	$ 662

(a) Includes current and noncurrent asset for Generation and current and noncurrent liability for ComEd of $111 million and $345 million, respectively, related to the fair value of Generation's and ComEd's five-year financial swap contract.
(b) As of December 31, 2008, collateral of $177 million, $252 million, $274 million and $50 million are netted against current and noncurrent assets and current and noncurrent liabilities, respectively. The total cash collateral received was $753 million at December 31, 2008.
(c) Amounts related to the five-year financial swap between Generation and ComEd are eliminated in consolidation.

	December 31, 2007			
	Generation [a][b]	ComEd [a]	Intercompany Elimination [c]	Exelon
Current assets	$ 247	$ 13	$ (13)	$ 247
Noncurrent assets	51	443	(443)	51
Total mark-to-market energy contract assets	298	456	(456)	298
Current liabilities	(247)	—	13	(234)
Noncurrent liabilities	(741)	—	443	(298)
Total mark-to-market energy contract liabilities	(988)	—	456	(532)
Total mark-to-market energy contract net assets (liabilities)	$(690)	$456	$ —	$(234)

(a) Includes current and noncurrent liability for Generation and current and noncurrent asset for ComEd of $13 million and $443 million, respectively, related to the fair value of Generation's and ComEd's five-year financial swap contract.
(b) As of December 31, 2007, collateral of $104 million, $23 million, $63 million and $82 million are netted against current and noncurrent assets and current and noncurrent liabilities, respectively. The total cash collateral posted net of cash collateral received was $272 million at December 31, 2007.
(c) Amounts related to the five-year financial swap between Generation and ComEd are eliminated in consolidation.

The majority of Generation's contracts are non-exchange-traded contracts valued using prices provided by external sources, primarily price quotations available through brokers or over-the-counter, on-line exchanges. Prices reflect the average of the bid-ask mid-point prices obtained from all sources that Generation believes provide the most liquid market for the commodity. The terms for which such price information is available vary by commodity, region and product. The remainder of the assets, which are primarily option contracts, represents contracts for which external valuations are not available. These contracts are valued using the Black model, an industry standard option valuation model.

The fair values reflect the level of forward prices and volatility factors as of December 31, 2008 and may change as a result of changes in these factors. Management uses its best estimates to determine the fair value of commodity and derivative contracts Generation and ComEd hold and sell. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors and credit exposure. It is possible, however, that future market prices could vary from those used in recording assets and liabilities from the swap between Generation and ComEd, energy marketing, trading activities and such variations could be material.

The following tables, which present maturity and source of fair value of mark-to-market energy contract net assets (liabilities), provides 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 asset or (liability). Second, the tables provide the maturity, by year, of the Registrants' net assets (liabilities), giving an indication of when these mark-to-market amounts will settle and either generate or require cash.

Exelon

	Maturities Within						
	2009	2010	2011	2012	2013	2014 and Beyond	Total Fair Value
Normal Operations, qualifying cash-flow hedge contracts [(a)(c)]:							
Prices provided by external sources	$ 419	$208	$ 98	$ 3	$ 3	$—	$ 731
Prices based on model or other valuation methods	1	—	4	5	—	—	10
Total	$ 420	$208	$102	$ 8	$ 3	$—	$ 741
Normal Operations, other derivative contracts [(b)(c)]:							
Actively quoted prices	$ 12	$—	$—	$—	$—	$—	$ 12
Prices provided by external sources	(324)	51	86		—	—	(187)
Prices based on model or other valuation methods	87	(6)	6	4	3	2	96
Total	$(225)	$ 45	92	4	$ 3	$ 2	$ (79)

(a) Mark-to-market gains and losses on contracts that qualify as cash-flow hedges are recorded in OCI. Excludes $456 million gain associated with the five-year financial swap with ComEd.
(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 in accordance with FSP FIN 39-1.

Generation

	Maturities Within						
	2009	2010	2011	2012	2013	2014 and Beyond	Total Fair Value
Normal Operations, qualifying cash-flow hedge contracts [(a)(c)]:							
Prices provided by external sources	$ 419	$208	$ 98	$ 3	$ 3	$—	$ 731
Prices based on model or other valuation methods	112	165	118	59	12		466
Total	$ 531	$373	$216	$ 62	$ 15	$	$1,197
Normal Operations, other derivative contracts [(b)(c)]:							
Actively quoted prices	$ 12	$—	$—	$—	$—	$—	$ 12
Prices provided by external sources	(324)	51	86		—	—	(187)
Prices based on model or other valuation methods	87	(6)	6	4	3	2	96
Total	$(225)	$ 45	92	4	$ 3	$ 2	$ (79)

(a) Mark-to-market gains and losses on contracts that qualify as cash-flow hedges are recorded in OCI. Includes $456 million gain associated with the five-year financial swap with ComEd.
(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 in accordance with FSP FIN 39-1.

ComEd

	Maturities Within					Total Fair Value
	2009	2010	2011	2012	2013	
Prices based on model or other valuation methods [(a)]	$(111)	$(165)	$(114)	$(54)	$(12)	$(456)

(a) Represents ComEd's net liabilities associated with the five-year financial swap with Generation.

The table below provides details of effective cash-flow hedges under SFAS No. 133 included in the balance sheet as of December 31, 2008. The data in the table gives an indication of the magnitude of SFAS No. 133 hedges Generation has in place; however, since under SFAS No. 133 not all hedges are recorded in OCI, the table does not provide an all-encompassing picture of Generation's hedges. The table also includes a roll-forward of accumulated OCI related to cash-flow hedges for the years ended December 31, 2008 and December 31, 2007, providing insight into the drivers of the changes (new hedges entered into during the period and changes in the value of existing hedges).

	Total Cash-Flow Hedge OCI Activity Net of Income Tax		
	Generation [a]	ComEd	Exelon
	Energy-Related Hedges	Energy-Related Hedges	Energy-Related Hedges
Accumulated OCI derivative gain (loss) at January 1, 2007	$ 247	$ (4)	$ 243
Effective portion of changes in fair value	(786) [b]	1	(507)
Reclassifications from accumulated OCI to net income	(9)	3	(6)
Accumulated OCI derivative loss at December 31, 2007	$ (548) [a]	$—	$(270)
Effective portion of changes in fair value	1,075 [b]	—	541
Reclassifications from accumulated OCI to net income	328 [c]	—	314
Accumulated OCI derivative gain at December 31, 2008	$ 855 [a]	$—	$ 585

(a) Includes $275 million gain and $275 million loss, net of taxes, related to the fair value of the five-year financial swap contract with ComEd for 2008 and 2007, respectively.
(b) Includes $535 million gain and $275 million loss, net of taxes, of the effective portion of changes in fair value of the five-year financial swap contract with ComEd for the years ended December 31, 2008 and 2007, respectively.
(c) Includes $15 million gain, net of taxes, of reclassifications from accumulated OCI to net income related to the settlements of the five-year financial swap contract with ComEd for the year ended December 31, 2008.

Credit Risk

Generation

Generation's PPA with ComEd expired at the end of 2006. In September 2006, Generation participated in and won portions of the ComEd and Ameren electricity supply auctions. Beginning in 2007 and as a result of the auctions, Generation's sales to counterparties other than ComEd and PECO increased due to the expiration of the PPA with ComEd on December 31, 2006. Illinois Settlement Legislation passed during 2007 established a new procurement process in place of the procurement auctions. Generation participated in the 2008 ComEd RFP procurement process and will continue to have credit risk in connection with contracts for sale of electricity resulting from the alternative competitive procurement process. Generation has credit risk associated with counterparty performance on energy contracts which includes, but is not limited to, the risk of financial default or slow payment; therefore, Generation's credit risk profile has changed based on the credit worthiness of the new and existing counterparties, including ComEd and Ameren. For additional information on the Illinois auction and the various regulatory proceedings, see Note 3 of the Notes to Consolidated Financial Statements.

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 allows for cross product netting. In addition to payment netting language in the enabling agreement, the credit department establishes margining thresholds and collateral requirements for each counterparty, which are defined in each contract. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including 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. The credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis. See the Collateral section below for additional information.

The following tables provide information on Generation's credit exposure, net of collateral, as of December 31, 2008. 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 Regional Transmission Organizations (RTOs), Independent System Operators (ISOs) and New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE) commodity exchanges, which are discussed below. Additionally, the figures in the tables below do not include receivables of $159 million and $126 million, respectively, related to the supplier forward agreement with ComEd and the PPA with PECO.

Rating as of December 31, 2008	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	$1,553	$440	$1,113	1	$205
Non-investment grade	5	2	3	—	—
No external ratings					
Internally rated—investment grade	6	—	6	—	—
Internally rated—non-investment grade	29	8	21	—	—
Total	$1,593	$450	$1,143	1	$205

	Maturity of Credit Risk Exposure			
Rating as of December 31, 2008	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$1,116	$437	$—	$1,553
Non-investment grade	5	—	—	5
No external ratings				
Internally rated—investment grade	6	—	—	6
Internally rated—non-investment grade	21	8	—	29
Total	$1,148	$445	$—	$1,593

Net Credit Exposure by Type of Counterparty	As of December 31, 2008
Financial institutions	$ 383
Investor-owned utilities, marketers and power producers	709
Coal	14
Other	37
Total	$1,143

ComEd

Due to the expiration of ComEd's PPA with Generation on December 31, 2006, ComEd began procuring power from multiple suppliers, including Generation. The power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on the price of energy in the spot market compared to the contracted price with each supplier. If the price of energy in the spot market exceeds the contract 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, 2008, ComEd did not have any credit exposure to suppliers, as the price of energy in the spot market did not exceed the contract prices with suppliers.

PECO

PECO has a PPA with Generation under which Generation has agreed to supply PECO with all of PECO's electric supply needs through 2010. Generation supplies electricity to PECO from its portfolio of generation assets, PPAs and other market sources at fixed prices that are currently below current market prices. The price for this electricity is essentially equal to the energy revenues earned from customers as specified by PECO's 1998 restructuring settlement mandated by the Competition Act. As noted under Item 1A. Risk Factors in Exelon's 2008 Form 10-K, PECO could be negatively impacted if Generation could not perform under the PPA.

For PECO's natural gas supply contracts, no disclosure is necessary for the year ended December 31, 2008 because PECO has no price exposure as the fixed-contract obligation costs are greater than projected market prices.

Collateral. As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of capacity, energy, fuels and emissions allowances. 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.

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 lines 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.

Beginning in 2007, under the Illinois auction rules and the supplier forward contracts that Generation entered into with ComEd and Ameren, collateral postings will be one-sided from Generation only. That is, if market prices fall below ComEd's or Ameren's contracted price levels, neither ComEd nor Ameren is required to post collateral; however, if market prices rise above contracted price levels with ComEd or Ameren, Generation may be required to post collateral once certain credit limits are exceeded. Under the terms of the 5-year financial swap contract with ComEd, there are no immediate collateral provisions on either party. However, the swap contract also provides that: (1) if ComEd is upgraded to investment grade by Moody's Investor Service or Standard & Poor's and then is later downgraded below investment grade, or (2) if Generation is downgraded below investment grade by Moody's Investor Service or Standard & Poor's, collateral postings would be required by the applicable party depending on how market prices compare to the contracted price levels. As of December 31, 2008, there was no cash collateral or letters of credit posted between any suppliers, including Generation, and ComEd associated with the supplier forward contracts.

As of March 19, 2008, ComEd was upgraded to investment grade by Standard & Poor's, and therefore, the above condition has been satisfied such that if ComEd is later downgraded, it could be subject to margining depending on market prices at that time. Under no circumstances would collateral postings exceed $200 million from either ComEd or Generation under the swap contract. Illinois Settlement Legislation passed during 2007 established a new procurement process in place of the procurement auctions. Generation participated in the 2008 ComEd RFP procurement process. Under the terms of the RFP, collateral postings are required of both ComEd and the counterparty supplier, including Generation, should exposures between market prices and contracted prices exceed established thresholds outlined in the agreement. As stipulated in the Illinois legislation as well as the ICC-approved procurement tariff, ComEd is permitted to recover its costs of procuring power and energy plus any prudent costs that a utility incurs in arranging and providing for the supply of electric power and energy. Thus all costs associated with collateral postings are recoverable from retail customers through ComEd's procurement tariff. See Note 3 of the Notes to Consolidated Financial Statements for further information.

As of December 31, 2008, Generation was holding $ 758 million of cash collateral deposits received from counterparties, of which $753 million was offset against mark-to-market assets and liabilities, in accordance with FSP FIN 39-1. See Note 18 of the Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

PECO does not obtain collateral from suppliers under its natural gas supply agreements.

RTOs and ISOs. 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 enters into commodity transactions on NYMEX and ICE. The NYMEX and ICE clearinghouse acts 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.

Generation and PECO

Fuel Procurement. Generation procures coal through annual, short-term and spot-market purchases and natural gas through annual, monthly and spot-market purchases. Nuclear fuel assemblies are obtained 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 60% of Generation's uranium concentrate requirements from 2009 through 2013 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 Notes to Consolidated Financial Statements for additional information regarding uranium and coal supply agreement matters.

PECO procures natural gas from suppliers under both short-term and long-term contracts. 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 agreements is mitigated by its ability to recover its natural gas costs through the PAPUC purchased gas cost clause that allows PECO to adjust rates to reflect realized natural gas prices.

ComEd and PECO

Credit risk for ComEd and PECO is managed by credit and collection policies, which are consistent with state regulatory requirements. ComEd and PECO are each currently obligated to provide service to all electric customers within their respective franchised territories. ComEd and PECO record a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. ComEd will continue to monitor the impact of the power prices on its customer payment practices as it relates to its provision for uncollectible accounts. ComEd and PECO will continue to monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. The Illinois Settlement Legislation (discussed in Note 3 of the Notes to Consolidated Financial Statements) prohibits utilities, including ComEd, from terminating electric service to a residential electric space heat customer due to nonpayment between December 1 of any year and March 1 of the following year. 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. ComEd and PECO will monitor the impact of its disconnection practices and will make any necessary adjustments to the provision for uncollectible accounts. PECO's provision for uncollectible accounts could be affected by changes in future prices as well as changes in PAPUC regulations. ComEd and PECO did not have any customers representing over 10% of their revenues as of December 31, 2008.

Exelon

Exelon's consolidated balance sheets, as of December 31, 2008, included a $577 million net investment in direct financing leases. The investment in direct financing leases represents future minimum lease payments due at the end of the thirty-year lives of the leases of $1.5 billion, less unearned income of $915 million. The future minimum lease payments are supported by collateral and credit enhancement measures including letters of credit, surety bonds and credit swaps. Management regularly evaluates the credit worthiness of Exelon's counterparties to these direct financing leases.

Interest-Rate Risk

The Registrants use a combination of fixed-rate and variable-rate debt to reduce 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, 2008, Exelon had $100 million of notional amounts of fair-value hedges outstanding. As of December 31, 2008, a hypothetical 10% increase in the interest rates associated with variable-rate debt would result in $1.4 million, $1.2 million and less than $1 million decrease in Exelon's, Generation's and ComEd's, respectively, pre-tax earnings.

Equity Price Risk

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, 2008, 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 values 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 nuclear decommissioning trust fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $247 million reduction in the fair value of the trust assets.

Exelon and Generation maintain trust assets associated with defined benefit pension and other postretirement benefits. See Defined Benefit Pension and Other Postretirement Benefits in the Critical Accounting Estimates section for information regarding the pension and other postretirement benefit trust assets.

CERTIFICATIONS

The CEO of Exelon has made the required annual certifications for 2008 to the New York Stock Exchange that Exelon is in compliance with the listing standards of the exchange. 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 2008 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, 2008. 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, 2008, Exelon's internal control over financial reporting was effective.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2008, 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 6, 2009

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, 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 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, 2008, 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.

As discussed in Note 1 to the consolidated financial statements, Exelon Corporation changed its method of accounting for uncertain tax positions as of January 1, 2007, and its method of accounting for nuclear decommissioning trust fund investments as of January 1, 2008.

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 6, 2009

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Operations

(in millions, except per share data)	For the Years Ended December 31, 2008	2007	2006
Operating revenues	$18,859	$18,916	$15,655
Operating expenses			
Purchased power	4,270	5,282	2,683
Fuel	2,312	2,360	2,549
Operating and maintenance	4,566	4,289	3,868
Impairment of goodwill	—	—	776
Depreciation and amortization	1,634	1,520	1,487
Taxes other than income	778	797	771
Total operating expenses	13,560	14,248	12,134
Operating income	5,299	4,668	3,521
Other income and deductions			
Interest expense	(699)	(647)	(616)
Interest expense to affiliates, net	(133)	(203)	(264)
Equity in losses of unconsolidated affiliates	(26)	(106)	(111)
Other, net	(407)	460	266
Total other income and deductions	(1,265)	(496)	(725)
Income from continuing operations before income taxes	4,034	4,172	2,796
Income taxes	1,317	1,446	1,206
Income from continuing operations	2,717	2,726	1,590
Discontinued operations			
Income (loss) from discontinued operations (net of taxes of $1, $3 and $0, respectively)	(1)	6	(2)
Gain on disposal of discontinued operations (net of taxes of $14, $2 and $2, respectively)	21	4	4
Income from discontinued operations	20	10	2
Net income	$ 2,737	$ 2,736	$ 1,592
Average shares of common stock outstanding			
Basic	658	670	670
Diluted	662	676	676
Earnings per average common share—basic:			
Income from continuing operations	$ 4.13	$ 4.06	$ 2.37
Income from discontinued operations	0.03	0.02	—
Net income	$ 4.16	$ 4.08	$ 2.37
Earnings per average common share—diluted:			
Income from continuing operations	$ 4.10	$ 4.03	$ 2.35
Income from discontinued operations	0.03	0.02	—
Net income	$ 4.13	$ 4.05	$ 2.35
Dividends per common share	$ 2.03	$ 1.76	$ 1.60

See Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Cash Flows

(in millions)	For the Years Ended December 31, 2008	2007	2006
Cash flows from operating activities			
Net income	$ 2,737	$ 2,736	$ 1,592
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel amortization	2,308	2,183	2,132
Impairment charges	—	—	894
Deferred income taxes and amortization of investment tax credits	374	(104)	73
Net realized and unrealized mark-to-market transactions	(515)	102	(83)
Other non-cash operating activities	1,233	664	197
Changes in assets and liabilities:			
Accounts receivable	67	(585)	(62)
Inventories	(109)	9	(59)
Accounts payable, accrued expenses and other current liabilities	136	330	67
Counterparty collateral asset	670	(246)	259
Counterparty collateral liability	357	(270)	172
Income taxes	(38)	160	69
Restricted cash	14	(15)	—
Pension and non-pension postretirement benefit contributions	(230)	(204)	(180)
Other assets and liabilities	(453)	(264)	(236)
Net cash flows provided by operating activities	6,551	4,496	4,835
Cash flows from investing activities			
Capital expenditures	(3,117)	(2,674)	(2,418)
Proceeds from nuclear decommissioning trust fund sales	17,202	7,312	4,793
Investment in nuclear decommissioning trust funds	(17,487)	(7,527)	(5,081)
Proceeds from sales of investments	—	95	2
Change in restricted cash	29	(45)	(9)
Other investing activities	(5)	(70)	(49)
Net cash flows used in investing activities	(3,378)	(2,909)	(2,762)
Cash flows from financing activities			
Issuance of long-term debt	2,265	1,621	1,370
Retirement of long-term debt	(1,398)	(262)	(402)
Retirement of long-term debt to financing affiliates	(1,038)	(1,020)	(910)
Retirement of short-term debt	—	—	(300)
Change in short-term debt	(405)	311	(685)
Dividends paid on common stock	(1,335)	(1,180)	(1,071)
Proceeds from employee stock plans	130	215	184
Purchase of treasury stock	(436)	(1,208)	(186)
Purchase of forward contract in relation to certain treasury stock	(64)	(79)	—
Other financing activities	68	102	11
Net cash flows used in financing activities	(2,213)	(1,500)	(1,989)
Increase in cash and cash equivalents	960	87	84
Cash and cash equivalents at beginning of period	311	224	140
Cash and cash equivalents at end of period	$ 1,271	$ 311	$ 224

See Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(in millions)	December 31, 2008	2007
Assets		
Current assets		
Cash and cash equivalents	$ 1,271	$ 311
Restricted cash and investments	75	118
Accounts receivable, net		
Customer	1,928	2,041
Other	324	611
Mark-to-market derivative assets	410	247
Inventories, net, at average cost		
Fossil fuel	315	252
Materials and supplies	528	471
Deferred income taxes	—	102
Other	517	427
Total current assets	5,368	4,580
Property, plant and equipment, net	25,813	24,153
Deferred debits and other assets		
Regulatory assets	5,940	5,133
Nuclear decommissioning trust funds	5,500	6,823
Investments	670	668
Investments in affiliates	45	63
Goodwill	2,625	2,625
Mark-to-market derivative assets	507	55
Other	1,349	1,261
Total deferred debits and other assets	16,636	16,628
Total assets	$47,817	$45,361

See Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(in millions)	December 31, 2008	2007
Liabilities and shareholders' equity		
Current liabilities		
Short-term borrowings	$ 211	$ 616
Long-term debt due within one year	29	605
Long-term debt to ComEd Transitional Funding Trust and PECO Energy Transition Trust due within one year	319	501
Accounts payable	1,416	1,450
Mark-to-market derivative liabilities	214	234
Accrued expenses	1,151	1,240
Other	740	983
Total current liabilities	4,080	5,629
Long-term debt	11,397	9,915
Long-term debt due to PECO Energy Transition Trust	805	1,505
Long-term debt to other financing trusts	390	545
Deferred credits and other liabilities		
Deferred income taxes and unamortized tax credits	4,939	5,081
Asset retirement obligations	3,734	3,812
Pension obligations	4,111	777
Non-pension postretirement benefits obligations	2,255	1,717
Spent nuclear fuel obligation	1,015	997
Regulatory liabilities	2,520	3,301
Mark-to-market derivative liabilities	24	298
Other	1,413	1,560
Total deferred credits and other liabilities	20,011	17,543
Total liabilities	36,683	35,137
Commitments and contingencies		
Preferred securities of subsidiary	87	87
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 658 and 661 shares outstanding at December 31, 2008 and 2007, respectively)	8,816	8,579
Treasury stock, at cost (35 and 28 shares held at December 31, 2008 and 2007, respectively)	(2,338)	(1,838)
Retained earnings	6,820	4,930
Accumulated other comprehensive loss, net	(2,251)	(1,534)
Total shareholders' equity	11,047	10,137
Total liabilities and shareholders' equity	$47,817	$45,361

See Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

(Dollars in millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholders' Equity
Balance, December 31, 2005	675,809	$7,987	$ (444)	$ 3,206	$(1,624)	$ 9,125
Net income	—	—	—	1,592	—	1,592
Long-term incentive plan activity	6,385	313	—	—	—	313
Employee stock purchase plan issuances	280	14	—	—	—	14
Common stock purchases	—	—	(186)	—	—	(186)
Common stock dividends declared	—	—	—	(1,372)	—	(1,372)
Adjustment to initially apply Statement of Financial Accounting Standards No. 158 (SFAS No. 158), net of income taxes of $804	—	—	—	—	(1,268)	(1,268)
Other comprehensive income, net of income taxes of $1,179	—	—	—	—	1,789	1,789
Balance, December 31, 2006	682,474	$8,314	$ (630)	$ 3,426	$(1,103)	$10,007
Net income	—	—	—	2,736	—	2,736
Long-term incentive plan activity	6,455	328	—	—	—	328
Employee stock purchase plan issuances	254	16	—	—	—	16
Common stock purchases	—	(79)	(1,208)	—	—	(1,287)
Common stock dividends declared	—	—	—	(1,219)	—	(1,219)
Adoption of Financial Accounting Standards Board Interpretation No. 48 (FIN 48)	—	—	—	(13)	—	(13)
Other comprehensive loss, net of income taxes of $(290)	—	—	—	—	(431)	(431)
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 declared	—	—	—	(1,007)	—	(1,007)
Adoption of Statement of Financial Accounting Standards Board No. 159 (FAS 159), net of income taxes of $286	—	—	—	160	(160)	—
Other comprehensive loss, net of income taxes of $(354)	—	—	—	—	(557)	(557)
Balance, December 31, 2008	692,953	$8,816	$(2,338)	$ 6,820	$(2,251)	$11,047

See Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Comprehensive Income

(in millions)	For the Years Ended December 31, 2008	2007	2006
Net income	$ 2,737	$2,736	$1,592
Other comprehensive income (loss)			
Pension and non-pension postretirement benefit plans:			
Prior service (benefit) reclassified to periodic benefit cost, net of income taxes of $(6), $(4), $0	(9)	(9)	—
Actuarial loss reclassified to periodic cost, net of income taxes of $52, $57, $0	60	74	—
Transition obligation reclassified to periodic cost, net of income taxes of $2, $2, $0	3	3	—
Pension and non-pension postretirement benefit plan valuation adjustment, net of income taxes of $(959), $1, $0	(1,459)	19	—
Minimum pension liability, net of income taxes of $0, $0, and $674, respectively	—	—	1,138
Net unrealized gain (loss) on cash-flow hedges, net of income taxes of $563, $(345) and $368, respectively	855	(513)	559
Unrealized (loss) gain on marketable securities, net of income taxes of $(6), $(1), and $137, respectively	(7)	(5)	92
Other comprehensive (loss) income	(557)	(431)	1,789
Comprehensive income	$ 2,180	$2,305	$3,381

See Notes to Consolidated Financial Statements

1. Significant Accounting Policies

Description of Business

Exelon Corporation (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 Exelon Generation Company, LLC (Generation). The energy delivery businesses include the purchase and regulated retail sale of electricity and the provision of distribution and transmission services by Commonwealth Edison Company (ComEd) in northern Illinois, including the City of Chicago, and by PECO Energy Company (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

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 a risk and rewards model that identifies Exelon or one of its subsidiaries as the primary beneficiary of the variable interest entity. 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.

Exelon's corporate operations, some of which are performed through its business services subsidiary, Exelon Business Services Company, LLC (BSC), provide Exelon's 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 stock. Exelon has reflected the third-party interests in ComEd as minority interests and PECO's preferred stock 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. AmerGen Energy Company, LLC (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). Effective January 8, 2009, AmerGen was merged into Generation, and Generation now holds the operating licenses for Clinton, TMI and Oyster Creek and owns and operates those plants.

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

Use of Estimates

The preparation of financial statements of each of Exelon, Generation, ComEd and PECO (collectively, the Registrants) in conformity with accounting principles generally accepted in the United States (GAAP) requires management to make estimates and

assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Areas in which significant estimates have been made include, but are not limited to, the accounting for nuclear decommissioning costs and other asset retirement obligations (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.

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 Illinois Commerce Commission (ICC) and the Pennsylvania Public Utility Commission (PAPUC) under state public utility laws, the Federal Energy Regulatory Commission (FERC) under various Federal laws, and the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (PUHCA) prior to its repeal effective February 8, 2006. Exelon, ComEd and PECO apply Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). SFAS No. 71 requires ComEd and PECO to record in their 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 assumption that all costs will be recoverable from customers through rates. Exelon believes that it is probable that its currently recorded regulatory assets and liabilities will be recovered in future rates. However, Exelon, ComEd and PECO continue to evaluate their respective abilities to apply SFAS No. 71, 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 provisions of SFAS No. 71, Exelon, ComEd and PECO would be required to eliminate from their financial statements the effects of regulation for that portion, which would have a material impact on their financial condition and results of operations. See Note 3—Regulatory Issues for additional information.

Segment Information

Exelon has three reportable and operating segments: Generation, ComEd and PECO. See Note 20—Segment Information for additional information regarding Exelon's segments. Generation, ComEd and PECO each operate in a single business segment.

Variable Interest Entities

Generation enters into power purchase agreements (PPAs) with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to customers, including ComEd and PECO. Generation accounts for its leases in accordance with SFAS No. 13, "Accounting for Leases" and determines whether long-term PPAs are leases pursuant to Emerging Issues Task Force (EITF) Issue No. 01-8, "Determining Whether an Arrangement is a Lease". Several of Generation's long-term PPAs have been determined to be operating leases which are not considered variable interests under the guidance of FASB Interpretation No. 46(R) "Consolidation of Variable Interest Entities" and FIN 46 (revised December 2003) (FIN 46-R). Generation's PPAs that are not deemed to be operating leases are typically either non derivatives, or derivatives that qualify for the normal purchases and normal sales exception. Generation has evaluated these PPAs under the provisions of FIN 46 (R), and determined that either it has no variable interest in the PPA counterparties or, where Generation does have variable interests in these PPA counterparties, it is not the primary beneficiary of these counterparties and, therefore, consolidation is not required. These conclusions are based on the following factors: the PPAs do not have residual value guarantees and purchase options, Generation has no equity investments in the counterparties and does not incur expected losses related to the loss of plant value, the PPAs are based on market terms at their inception and Generation does not bear any operational risk related to the plants. Generation's financial exposure to its PPAs relates to its fixed capacity payments, which are disclosed in Note 18—Commitments and Contingencies.

The financing trusts of ComEd, namely ComEd Financing II, ComEd Financing III, ComEd Funding LLC (ComEd Funding) and ComEd Transitional Funding Trust (CTFT), and the financing trusts of PECO, namely PECO Trust III, PECO Energy Capital Trust IV (PECO Trust IV) and PECO Energy Transition Trust (PETT), are not consolidated in Exelon's, ComEd's and PECO's financial statements pursuant to the provisions of FIN 46-R. ComEd Funding, CTFT and PETT were created for the sole purpose of issuing debt obligations to securitize intangible transition property of ComEd and PECO; and the other entities were created to issue mandatorily redeemable trust preferred securities. As of December 31, 2008, the only remaining variable interest entity for ComEd is ComEd Financing III, as the other entities were dissolved during 2008.

ComEd and PECO have concluded that they are not the primary beneficiaries of their respective trusts because investors in the trusts' securities, not ComEd and PECO, bear the risk of loss related to those securities. ComEd and PECO, as the sponsors of the

financing trusts are obligated to pay the operating expenses of the trusts. ComEd's and PECO's balance sheets include payable to affiliate amounts due to their respective financing trusts, as well as investments in their respective trusts. See Note 21—Related Party Transactions regarding information on the amounts recorded with respect to the financing trusts within the Consolidated Financial Statements.

The maximum exposure to loss as a result of ComEd's and PECO's involvement with the financing trusts was $6 million and $39 million respectively, at December 31, 2008 and $21 million and $57 million, respectively, at December 31, 2007. ComEd's and PECO's maximum exposure to loss is determined based on the current carrying value of investments made in the variable interest entities. ComEd's and PECO's estimated range of exposure to loss related to the financing trusts is any amount up to the current carrying value of investments made in the variable interest entities. ComEd and PECO have not provided any non-contractually required financial support to the trusts during the year ended December 31, 2008.

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 regional transmission organization (RTO) and independent system operator (ISO) markets that facilitate the dispatch of energy and energy-related products, Exelon and Generation report sales and purchases conducted within these markets on a net hourly basis in either revenues or purchased power on Exelon's and Generation's Consolidated Statements of Operations, 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 2008, ComEd recorded an immaterial amount associated with hours where it had net spot market sales.

Option Contracts, Swaps, and Commodity Derivatives. Premiums received and paid on option contracts and swap arrangements are amortized to revenue or expensed over the terms of the contracts. Certain option contracts and swap arrangements which meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenues or expenses, unless hedge accounting is applied. If the derivatives meet hedging criteria, changes in fair value are recorded in other comprehensive income (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, ComEd records the fair value of the swap as well as an offsetting regulatory asset or liability on its balance sheet.

Trading Activities. Exelon and Generation account for their trading activities under the provisions of EITF Issue No. 02-3, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3), which requires revenue and energy 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.

Physically Settled Derivative Contracts. Exelon and Generation account for realized gains and losses on physically settled derivative contracts not "held for trading purposes" in accordance with EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133) and Not 'Held for Trading Purposes' as Defined in EITF Issue No. 02-3, 'Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities'" (EITF 03-11).

Pursuant to EITF 03-11, Exelon and Generation present derivative contracts not physically settled and not "held for trading purposes", net within revenues, purchased power and fuel expenses, which totaled $310 million, $336 million and $561 million during 2008, 2007 and 2006, respectively.

Acquisition Costs

Through December 31, 2008, costs related to acquisitions which are not considered probable have been expensed as incurred. See the discussion of SFAS No. 141-R below for information on the prospective treatment of acquisition costs related to business combinations after January 1, 2009.

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. Beginning January 1, 2007, the Registrants began accounting for uncertain income tax positions in accordance with FIN 48, "Accounting for Uncertainty in Income Taxes, an Interpretation of Financial Accounting Standards Board (FASB) Interpretation No. 48 (FIN 48). See Note 11—Income Taxes for information regarding the Registrants' accounting for uncertain income tax positions. Prior to January 1, 2007, the Registrants estimated their uncertain income tax obligations in accordance with SFAS No. 109, "Accounting for Income Taxes" (SFAS No. 109), SFAS No. 5 "Accounting for Contingencies" (SFAS No. 5), and Statement of Financial Accounting Concepts No. 6, "Elements of Financial Statements-a replacement of FASB Concepts Statement No. 3 (incorporating an amendment of FASB Concepts Statement No. 2)". The Registrants recognize accrued interest related to unrecognized tax benefits in interest expense or interest income in other income and deductions on their Consolidated Statements of Operations.

Pursuant to the Internal Revenue Code (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).

Generation, ComEd and PECO are parties to an agreement (Tax Sharing Agreement) with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits. 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 the parent is reallocated to other members. That allocation is treated as a contribution to the capital of the party receiving the benefit.

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 in accordance with EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent." See Note 19—Supplemental Financial Information for ComEd's and PECO's utility taxes that are presented on a gross basis.

Losses on Reacquired and Retired Debt

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. Losses on Exelon's and Generation's reacquired debt are recognized as incurred in the Registrants' Consolidated Statements of Operations.

Cash and Cash Equivalents

The Registrants consider highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Investments

As of December 31, 2008 and 2007, 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, 2008 and December 31, 2007, 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, 2008, ComEd's restricted cash primarily represented funds to be used for the rate relief program. As of December 31, 2007, ComEd's restricted cash primarily represented funds to be used for the rate relief program and collateral received under the supplier forward contracts. See Note 3–Regulatory Issues for further information. As of December 31, 2008 and 2007, PECO's restricted cash primarily represented funds from the sales of assets that were subject to PECO's Mortgage Indenture. PECO's restricted cash is not available for general operations until released from the Mortgage Indenture.

Restricted cash and investments not available for general operations or to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2008 and 2007, Exelon and Generation had restricted cash and investments in the nuclear decommissioning trust funds 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. The allowance is based on known troubled accounts, historical experience and other currently available evidence. 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 customers' accounts are written-off consistent with approved regulatory requirements.

The following table summarizes the provision for uncollectible accounts for the years ended December 31, 2008, 2007 and 2006:

For the Year Ended December 31,	
2008	$247
2007	132
2006	94

Inventories

Inventory is recorded at the lower of cost or market, and 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 then expensed or capitalized to plant, 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. The Exelon and Generation emission allowance balances as of December 31, 2008 and 2007 were $80 million and $86 million, respectively.

Marketable Securities

All marketable securities are reported at fair value pursuant to SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115) or SFAS No. 159, "The Fair Value Option for Financial Assets and Liabilities – Including an Amendment of FASB Statement No. 115" (SFAS No. 159) as applicable. Marketable securities held in the nuclear decommissioning trust funds are classified as trading securities pursuant to SFAS No. 115 as a result of the adoption of SFAS No. 159 effective January 1, 2008. All securities that are not held by the nuclear decommissioning trust funds are classified as available-for-sale securities pursuant to SFAS No. 115. Realized and unrealized gains and losses, net of tax, on Generation's nuclear decommissioning trust funds associated with the former ComEd and former PECO nuclear generating units (Regulated 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 nuclear decommissioning trust funds associated with the former AmerGen nuclear generating units and the unregulated portions of the Peach Bottom nuclear generating units (Unregulated 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 shall be written down to fair value as a new cost basis and the amount of the write-down shall be included in earnings. See Note 12—Asset Retirement Obligations for information regarding marketable securities held by nuclear decommissioning trust funds, including the adoption of SFAS No. 159, and Note 19—Supplemental Financial Information for additional information regarding ComEd's and PECO's regulatory assets and liabilities.

Deferred Energy Costs

Starting in 2007, ComEd's electricity and transmission costs are recoverable or refundable under ComEd's ICC and / or FERC approved retail rates. ComEd recovers or refunds the difference between the actual cost of electricity and transmission and the amount included in rates charged to its customers. Differences between the amounts billed to customers and the actual costs recoverable are deferred and recovered or refunded in future periods by means of prospective monthly adjustments to rates.

PECO's natural gas rates are subject to a purchased gas cost adjustment clause designed to recover or refund the difference between the actual cost of purchased gas and the amount included in rates. Differences between the amounts billed to customers and the actual costs recoverable are deferred and recovered or refunded in future periods by means of prospective quarterly adjustments to rates.

See Note 19—Supplemental Financial Information for additional information regarding deferred energy costs for Exelon, ComEd and PECO.

Leases

The Registrants account for leases in accordance with SFAS No. 13, "Accounting for Leases" and determine whether their long-term power purchase and sales contracts are leases pursuant to EITF Issue No. 01-8, "Determining Whether an Arrangement is a Lease" (EITF 01-8). At the inception of a contract determined to be a lease, or subsequent modification, the Registrants determine whether the lease is an operating or capital lease based upon its terms and characteristics. 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.

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 under SFAS No. 34, "Capitalization of Interest Costs" (SFAS No. 34) and allowance for funds used during construction (AFUDC) under SFAS No. 71. The cost of repairs, maintenance including planned major maintenance activities, and minor replacements of property is charged to maintenance expense as incurred.

For Generation, upon retirement, the cost of property is charged to accumulated depreciation. For ComEd and PECO, upon retirement, the cost of regulated 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 as these costs, as well as depreciation expense, are included in cost of service for rate-making purposes. ComEd's removal costs reduce the related regulatory liability. PECO's removal costs are capitalized when incurred and recorded to depreciation expense, as depreciated over the life of the new asset constructed consistent with PECO's regulatory recovery method. For unregulated property, the cost and accumulated depreciation of property, plant and equipment retired or otherwise disposed of are charged to accumulated depreciation.

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 spent nuclear fuel (SNF) is established per the Standard Waste Contract with the Department of Energy (DOE) and is expensed through fuel expense at one mill ($.001) per kilowatt-hour (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 long-term storage facility has not been completed. See Note 13 – Spent Nuclear Fuel Obligation for additional information.

Nuclear Outage Costs

Costs associated with nuclear outages, including planned major maintenance activities, are recorded 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 stations. 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 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. Through the year ended December 31, 2008, there have been no significant costs capitalized related to new site development; however, approximately $76 million of costs have been expensed at Generation 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 in accordance with Statement of Position (SOP) 98-1, "Accounting for the Costs of Computer Software Developed or Obtained for Internal Use". 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 a longer life, 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, 2008	$259
December 31, 2007	270

Amortization of capitalized software costs	
2008	$91
2007	79
2006	77

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 life 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 for all of Generation's operating nuclear generating stations. The estimated service lives of the fossil fuel and hydroelectric generating facilities are based on the remaining useful lives of the stations, which Generation periodically evaluates based on feasibility assessments as well as economic and capital requirements. See Note 5—Property, Plant and Equipment for further information regarding depreciation.

Amortization of regulatory assets is provided over the recovery period specified in the related legislation or regulatory agreement. See Note 19—Supplemental Financial Information for additional information regarding Generation's nuclear fuel, Generation's asset retirement cost and the amortization of ComEd's and PECO's regulatory assets.

Asset Retirement Obligations (ARO)

Asset retirement obligations are accounted for in accordance with FASB Statement No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143) and FIN 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47). FIN 47 requires the recognition of a liability for a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event. 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 based upon significant estimates and assumptions, including decommissioning cost studies, cost escalation studies, probabilistic cash flow models and discount rates. 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 conditional AROs are adjusted on an ongoing basis 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 and conditional 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 or, in the case of the majority of ComEd's and PECO's accretion, through an increase to regulatory assets due to the application of SFAS No. 71. See Note 12—Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC

Exelon and Generation apply SFAS No. 34 to calculate the costs during construction of debt funds used to finance non-regulated construction projects.

Exelon, ComEd and PECO apply SFAS No. 71 to calculate the 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 (see Note 19—Supplemental Financial Information).

The following table summarizes total cost incurred, capitalized interest and credits of AFUDC by year:

2008	Total incurred interest [(a)]	$800
	Capitalized interest	33
	Credits to AFUDC debt and equity	2
2007	Total incurred interest [(a)]	$896
	Capitalized interest	30
	Credits to AFUDC debt and equity	19
2006	Total incurred interest [(a)]	$914
	Capitalized interest	22
	Credits to AFUDC debt and equity	15

(a) Includes interest expense to affiliates.

Guarantees

In accordance with FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others" (FIN 45), 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 Registrant's release from risk 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. The recognition and subsequent adjustment of the liability are highly dependent upon the nature of the associated 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. 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, 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. Impairment may occur when the carrying value of the asset exceeds the future undiscounted cash flows. When the undiscounted cash flow analysis indicates a long-lived asset is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its fair value. An impairment would require the affected Registrant to reduce both the long-lived asset and current period earnings by the amount of the impairment. See Note 5 – Property, Plant and Equipment for a discussion of asset impairment evaluations made by Generation, including an evaluation made in connection with Exelon's proposed acquisition of NRG.

Exelon holds certain investments in direct financing leases. Exelon determines the investment in direct financing leases by incorporating an estimate of the residual values of the leased assets. On an annual basis Exelon reviews the estimated residual values of these leased assets 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 are 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 along with a corresponding reduction to the carrying amount of the investment. To date, no such losses have been recognized.

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. Pursuant to SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), 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 information regarding the application of SFAS No. 142 and the results of goodwill impairment studies that have been performed, which includes the $776 million goodwill impairment charge Exelon and ComEd recorded in 2006.

Derivative Financial Instruments

The Registrants account for derivative instruments in accordance with SFAS No. 133. Under SFAS No. 133, 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. 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 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 under SFAS No. 133, 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. See Note 9—Derivative Financial Instruments for additional information.

Retirement Benefits

Exelon's and Generation's defined benefit pension plans and postretirement benefit plans are accounted for in accordance with SFAS No. 87, "Employer's Accounting for Pensions" (SFAS No. 87), SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits" (SFAS No. 88), SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other than Pensions" (SFAS No. 106), FSP FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP FAS 106-2) and SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132-R" (SFAS No. 158), and are disclosed in accordance with SFAS No. 132-R, "Employers' Disclosures about Pensions and Other Postretirement Benefits—an Amendment of FASB Statements No. 87, 88, and 106" (revised 2003) and SFAS No. 158. Generation, ComEd and PECO participate in Exelon's defined benefit pension plans and postretirement plans. Separately,

AmerGen sponsored a defined benefit pension plan and postretirement plan for its employees; however, Exelon became the sponsor of these plans upon the merger of AmerGen into Generation on January 8, 2009.

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 as allowed by SFAS No. 87 and SFAS No. 106.

Exelon calculates the expected return on pension and other postretirement benefit plan assets by multiplying the expected rate of return on plan assets by the market-related value (MRV) of plan assets at the beginning of the year, taking into consideration anticipated contributions and benefit payments that are to be made during the year. SFAS No. 87 and SFAS No. 106 allow the MRV of plan assets to be 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. Exelon uses a calculated value when determining the MRV of the pension plan assets that adjusts for 20% of the difference between fair value and expected MRV of plan assets. This calculated value has the effect of stabilizing variability in assets to which Exelon applies that expected return. Exelon uses fair value when determining the MRV of the other postretirement benefit plan assets and the former AmerGen pension plan assets. See Note 14—Retirement Benefits for additional discussion of Exelon's and Generation's accounting for retirement benefits.

Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Prescription Drug Act). Through Exelon's postretirement benefit plans, the Registrants provide retirees with prescription drug coverage. The Prescription Drug Act was enacted on December 8, 2003. The Prescription Drug Act 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 is at least actuarially equivalent to the Medicare prescription drug benefit.

Exelon's annualized reduction in the net periodic postretirement benefit cost was approximately $38 million, $44 million and $40 million in 2008, 2007 and 2006, respectively, compared to the annual cost calculated without considering the effects of the Prescription Drug Act. The effect of the subsidy on the components of net periodic postretirement benefit cost for 2008, 2007 and 2006 included in the consolidated financial statements and Note 14—Retirement Benefits was as follows:

	2008	2007	2006
Amortization of the actuarial experience loss	$11	$16	$16
Reduction in current period service cost	9	10	9
Reduction in interest cost on the APBO	18	18	15

Treasury Stock

Treasury shares are recorded at cost. Any shares of common stock repurchased are held as treasury shares unless cancelled or reissued.

New Accounting Pronouncements

Exelon has identified the following new accounting pronouncements that either have been recently adopted or issued that may affect the Registrants upon adoption.

SFAS No. 157

In September 2006, the FASB issued Statement No. 157, "Fair Value Measurements" (SFAS No. 157). SFAS No. 157 defines fair value for financial accounting and reporting purposes, establishes a framework for measuring fair value and expands disclosures about fair value measurements but does not change the requirements to apply fair value in existing accounting standards. Under SFAS No. 157, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal or, in the absence of a principal, the most advantageous market. The standard clarifies that fair value should be based on the assumptions market participants would use when pricing the applicable asset or liability.

SFAS No. 157 was effective and adopted by the Registrants as of January 1, 2008. The adoption of SFAS No. 157 did not have a material impact on the Registrants' results of operations, cash flows or financial positions for the year ended December 31, 2008. See Note 8—Fair Value of Financial Assets and Liabilities for additional information regarding the adoption of SFAS No. 157.

In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-2, "Effective Date of FASB Statement No. 157" (FSP FAS 157-2), which delayed the effective date of SFAS No. 157 for all nonrecurring fair value measurements of nonfinancial assets and liabilities until fiscal years beginning after November 15, 2008. As of January 1, 2009, the Registrants have adopted this guidance for nonrecurring fair value measurement disclosures of nonfinancial assets and liabilities. The adoption of FSP FAS 157-2 did not have a material impact on the Registrants' results of operations, cash flows or financial positions.

On October 10, 2008, the FASB issued FSP FAS No. 157-3, "Fair Value Measurements" (FSP FAS 157-3), which clarifies the application of SFAS No. 157 in an inactive market and provides an example to demonstrate how the fair value of a financial asset is determined when the market for that financial asset is inactive. FSP FAS 157-3 was effective upon issuance, including prior periods for which financial statements had not been issued. The adoption of this standard did not have a material impact on the Registrants' results of operations, cash flows or financial positions.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115" (SFAS No. 159). SFAS No. 159 allows an entity to irrevocably elect fair value for the initial and subsequent measurement of certain financial instruments and other items that are not currently required to be measured at fair value. When the fair value option is elected and a company chooses to record eligible items at fair value, the company must report unrealized gains and losses on those items in results of operations at each subsequent reporting date. Additionally, the transition provisions of SFAS No. 159 permit a one-time election for existing positions at the adoption date, with a cumulative-effect adjustment included in opening retained earnings. All future changes in fair value will be reported in results of operations. Under SFAS No. 159, Exelon and Generation elected to apply the fair value option to the nuclear decommissioning trust fund investments. Prior to this election, only unrealized losses were recorded in the results of operations. This election could have a material impact to Exelon's and Generation's results of operations in future periods, as all unrealized gains and losses will be included in results of operations. As a result of this election, Exelon's and Generation's beginning balances of retained earnings as of January 1, 2008 increased by $160 million, net of deferred taxes of $286 million. In 2008, in light of credit market events, the impact of reclassifying these previously unrealized gains to retained earnings resulted in lower realized gains and higher unrealized and realized losses, and such impacts could continue in the periods over which those financial instruments are held. See Note 12—Asset Retirement Obligations for additional information regarding adoption of SFAS No. 159. ComEd and PECO did not elect the fair value option allowed by SFAS No. 159.

FSP FIN 39-1

In April 2007, the FASB issued FSP FASB Interpretation No. (FIN) 39-1, "Amendment of FASB Interpretation No. 39" (FSP FIN 39-1). This pronouncement amends FIN 39, "Offsetting of Amounts Related to Certain Contracts," to permit companies to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FSP FIN 39-1 was effective for the Registrants as of January 1, 2008. Exelon and Generation elected the accounting policies prescribed by FSP FIN 39-1, which did not impact net income. In addition, upon the adoption of FSP FIN 39-1, companies were permitted to change their accounting policy to offset or not offset fair value amounts recognized for derivative instruments under master netting agreements. As prescribed by FIN 39, Exelon and Generation elected to record derivative financial instruments in the balance sheet on a net basis. The effects of applying this pronouncement were recognized through retrospective application for all financial statements presented. See Note 9—Derivative Financial Instruments for additional information regarding adoption of FSP FIN 39-1. The provisions of FSP FIN 39-1 are not currently applicable to ComEd and PECO.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements" (SFAS No. 160). SFAS No. 160 clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS No. 160 requires that changes in a parent's ownership interest in a subsidiary be reported as an equity transaction in the consolidated financial statements when it does not result in a change in control of the subsidiary. When a change in a parent's ownership interest results in deconsolidation, a gain or loss should

be recognized in the consolidated financial statements. SFAS No. 160 must be applied prospectively as of January 1, 2009, except for the presentation and disclosure requirements, which are required to be applied retrospectively for all periods presented. The adoption of SFAS No. 160 will not have a material impact on the Registrants' results of operations, cash flows or financial positions; however, it could impact future transactions entered into by the Registrants.

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133" (SFAS No. 161). SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), by requiring enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS No. 161 requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. SFAS No. 161 will be effective for the Registrants as of January 1, 2009. As SFAS No. 161 provides only disclosure requirements, the adoption of this standard will not have a material impact on the Registrants' results of operations, cash flows or financial positions.

FSP FAS 142-3

In April 2008, the FASB issued FSP FAS No. 142-3, "Determination of the Useful Life of Intangible Assets" (FSP FAS 142-3). This pronouncement amends SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), regarding the factors that should be considered in developing the useful lives for intangible assets with renewal or extension provisions. FSP FAS 142-3 requires an entity to consider its own historical experience in renewing or extending similar arrangements, regardless of whether those arrangements have explicit renewal or extension provisions, when determining the useful life of an intangible asset. In the absence of such experience, an entity shall consider the assumptions that market participants would use about renewal or extension, adjusted for entity-specific factors. FSP FAS 142-3 also requires an entity to disclose information regarding the extent to which the expected future cash flows associated with an intangible asset are affected by the entity's intent and/or ability to renew or extend the arrangement. FSP FAS 142-3 will be effective for qualifying intangible assets acquired by the Registrants on or after January 1, 2009. The application of FSP FAS 142-3 is not expected to have a material impact on the Registrants' results of operations, cash flows or financial positions; however, it could impact future transactions entered into by the Registrants.

EITF 07-5

In June 2008, the FASB ratified EITF Issue No. 07-5, "Determining Whether an Instrument (or an Embedded Feature) is indexed to an Entity's Own Stock" (EITF 07-5), which supersedes EITF Issue No. 01-6, "The Meaning of 'Indexed to a Company's Own Stock'". SFAS No. 133 specifies that a contract issued or held by a company that is both indexed to its own stock and classified in stockholders' equity is not considered a derivative instrument for purposes of applying SFAS No. 133. EITF 07-5 provides guidance for applying the requirements of SFAS No. 133, requiring that both an instrument's contingent exercise provisions and its settlement provisions be evaluated to determine whether the instrument (or embedded feature) is indexed solely to an entity's own stock. EITF 07-5 will be effective for any outstanding or new arrangements as of January 1, 2009. The adoption and application of this standard is not expected to have a material impact on the Registrants' results of operations, cash flows or financial positions; however, it could impact future transactions entered into by the Registrants.

FSP FAS 140-4 and FIN 46(R)-8

In December 2008, the FASB issued FSP FAS 140-4 and FIN 46(R)-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities," (FSP FAS 140-4 and FIN 46(R)-8). This pronouncement amends FASB Statement No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities" to require public entities to provide additional disclosures about the transfers of financial assets. The pronouncement also amends FASB Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities," to require public enterprises to provide additional disclosures about their involvement with variable interest entities and qualifying special purpose entities. FSP FAS 140-4 and FIN 46(R)-8 were effective for the Registrants for the year ended December 31, 2008. As this FSP provides only disclosure requirements, the adoption of this standard did not have a material impact on the Registrants' results of operations, cash flows or financial positions. As a result, the Registrants have provided additional disclosure with respect to their involvement with Generation's power purchase agreements and the financing trusts of ComEd and PECO. See "Variable Interest Entities" above, for further information.

FSP FAS 132(R)-1

In December 2008, the FASB issued FSP FAS No. 132(R)-1, “Employers’ Disclosures about Postretirement Benefit Plan Assets” (FSP FAS 132(R)-1), which requires additional disclosures for employers’ pension and other postretirement benefit plan assets. As pension and other postretirement benefit plan assets were not included within the scope of SFAS No. 157, FSP FAS 132(R)-1 requires employers to disclose information about fair value measurements of plan assets similar to the disclosures required under SFAS No. 157, the investment policies and strategies for the major categories of plan assets, and significant concentrations of risk within plan assets. FSP FAS 132(R)-1 will be effective for the Registrants as of December 31, 2009. As FSP FAS 132(R)-1 provides only disclosure requirements, the adoption of this standard will not have a material impact on the Registrants’ results of operations, cash flows or financial positions.

FSP EITF 99-20-1

In January 2009, the FASB issued FSP EITF No. 99-20-1, “Amendments to the Impairment Guidance of EITF Issue No. 99-20” (FSP EITF 99-20-1). This pronouncement amends EITF 99-20, “Recognition of Interest Income and Impairment on Purchased Beneficial Interests and Beneficial Interests That Continue to Be Held by a Transferor in Securitized Financial Assets,” (EITF 99-20), to achieve more consistent determination of whether an other-than-temporary impairment has occurred. FSP EITF 99-21-1 also retains and emphasizes the objective of an other than-temporary impairment assessment and the related disclosure requirements in SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities," and other related guidance. FSP EITF 99-20-1 is effective for interim and annual reporting periods ending after December 15, 2008, and is required to be applied prospectively. The adoption of FSP EITF 99-20-1 did not have a material impact on the Registrants' results of operations, cash flows or financial positions.

SFAS No. 141-R

In December 2007, the FASB issued SFAS No. 141-R, “Business Combinations” (SFAS No. 141-R) which revised SFAS No. 141, “Business Combinations” (SFAS No. 141). This pronouncement became effective for the Registrants as of January 1, 2009. Under SFAS No. 141, organizations utilized the announcement date as the measurement date for the purchase price of the acquired entity. SFAS No. 141-R requires measurement at the date the acquirer obtains control of the acquiree, generally referred to as the acquisition date. SFAS No. 141-R will have a significant impact on the accounting for transaction and restructuring costs, as well as the initial recognition of contingent assets and liabilities assumed during a business combination. Under SFAS No. 141-R, transaction costs are required to be expensed as incurred. Additionally, adjustments to the acquired entity’s deferred tax assets and uncertain tax position balances occurring outside the measurement period are recorded as a component of income tax expense, rather than goodwill. As the provisions of SFAS No. 141-R are applied prospectively to business combinations for which the acquisition date occurs after the guidance becomes effective, the impact to the Registrants cannot be determined until the transactions occur.

2. Discontinued Operations

On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation’s sale of its investment in Sithe Energies, Inc. (Sithe). In addition, during 2003 and 2004, Exelon sold or wound down substantially all components of Exelon Enterprises Company, LLC (Enterprises). As a result, the results of operations and any gain or loss on the sale of these entities are presented as discontinued operations for 2008, 2007 and 2006 within Exelon’s (for Sithe and Enterprises) and Generation’s (for Sithe) Consolidated Statements of Operations and Comprehensive Income. See Note 18—Commitments and Contingencies for additional information regarding Generation’s sale of its investment in Sithe, including the expiration of $38 million, before taxes, of tax indemnifications in 2008, which is included in Discontinued Operations in Exelon’s and Generation’s Consolidated Statements of Operations.

3. Regulatory Issues

Illinois Settlement Agreement. In July 2007, following extensive discussions with legislative leaders in Illinois, ComEd, Generation, and other utilities and generators in Illinois reached an agreement (Illinois Settlement) with various parties concluding discussions of measures 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. Legislation reflecting the Illinois Settlement (Illinois Settlement Legislation) was signed into law in August 2007. The Illinois Settlement and the Illinois Settlement Legislation provide for the following, among other things:

- Various Illinois electric utilities, their affiliates, and generators of electricity in Illinois agreed to contribute approximately $1 billion over a period of four years to programs to provide rate relief to Illinois electricity customers and funding for the Illinois Power

Agency (IPA) created by the Illinois Settlement Legislation. ComEd and Generation committed to contributing $811 million to rate relief programs over four years (2007-2010) and partial 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 are recognized in the financial statements of Generation and ComEd as rate relief credits are applied to customer bills by ComEd and other Illinois utilities, as funding is paid to the IPA, or as operating expenses associated with the programs are incurred.

ComEd's Customers' Affordable Reliable Energy (CARE) initiative was established prior to the consummation of the Illinois Settlement to help mitigate the impacts of electricity rate increases in 2007 on certain customers after the expiration of the retail electric rate freeze transition period in Illinois and includes a variety of energy efficiency, low-income and senior citizen programs.

During the twelve months ended December 31, 2008 and 2007, Generation and ComEd recognized net costs from their contributions pursuant to the Illinois Settlement in their Statements of Operations as follows:

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
Other rate relief programs, including CARE [(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.

Year ended December 31, 2007	Generation	ComEd	Total credits issued to ComEd customers
Credits to ComEd customers [(a)]	$246	$ 33	$279
Credits to other Illinois utilities' customers [(a)]	157	—	n/a
Other rate relief programs, including CARE [(b)]	—	8	n/a
Funding of the IPA [(a)]	5	—	n/a
Total incurred costs	$408	$ 41	$279

(a) Recorded as a reduction in operating revenues.
(b) Recorded as a charge to operating and maintenance expense.

- Electric utilities are required to include cost-effective energy efficiency resources in their plans to meet incremental annual program energy savings goals of 0.2% of energy delivered to retail customers in the year commencing June 1, 2008, increasing annually to 2% of energy delivered in the year commencing June 1, 2015 and each year thereafter. Additionally, commencing June 1, 2008 and continuing for a period of ten years, 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. Failure to comply with the energy efficiency requirements in the Illinois Settlement Legislation would result in ComEd being subject to penalties, including losing control of the programs, and other charges. Pursuant to these requirements, ComEd filed its initial Energy Efficiency and Demand Response Plan with the ICC on November 15, 2007. On February 6, 2008, the ICC issued an order approving substantially all of ComEd's plan, including cost recovery. This plan began June 1, 2008 and is designed to meet the Illinois Settlement Legislation's energy efficiency and demand response goals for an initial three-year period, including reductions in delivered energy to all retail customers and in the peak demand of eligible retail customers.

- The procurement plans developed initially by the electric utilities for the fiscal year beginning June 1, 2008 must include 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. As stipulated in the Illinois Settlement Legislation, the IPA is responsible for all procurement plans for annual delivery periods starting in June 2009 and thereafter, and will acquire amounts of renewable energy resources that will cumulatively increase this percentage to at least 10% by June 1, 2015, with a goal of 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. Utilities

are allowed to pass through procurement costs of renewable resources. ComEd conducted a request for proposal (RFP) to procure renewable energy credits in late April 2008 to be used for compliance with Illinois' renewable energy requirements for the period June 2008 through May 2009. Under the ICC-approved RFP, ComEd is procuring approximately $19 million in renewable energy credits for delivery from June 2008 through mid-July 2009. ComEd started recovering these costs through rates in June 2008.

Illinois Procurement Proceedings. Beginning January 1, 2007, ComEd procured 100% of its load through staggered supplier forward contracts with various suppliers, including Generation. The supplier forward contracts resulted from an ICC-approved "reverse-auction" competitive bidding process, which permitted ComEd to recover its electricity procurement costs from retail customers without markup. The price for full requirements electric supply that resulted from the first auction was fixed through May 31, 2008, at which time the auction contracts for one-third of the load expired. The auction contracts for an additional one-third of the load will expire in May 2009 with auction contracts for the final third of the load expiring in May 2010. The Illinois Settlement Legislation amended the reverse auction competitive bidding process. Under the Illinois Settlement Legislation, the IPA, under the oversight of the ICC, will participate in the design of an electricity supply portfolio for ComEd and will administer a competitive process under which ComEd will procure its electricity supply resources for deliveries in the supply period beginning June 2009. In the interim, in December 2007, the ICC approved a plan under which ComEd is procuring power for the period from June 2008 through May 2009. Under this plan, standard block energy purchases, acquired through an ICC-approved RFP, coupled with purchases of energy, capacity and ancillary services in PJM Interconnection, LLC (PJM)-administered markets, are used to replace a portion of the auction contracts that expired on May 31, 2008. Additionally, spot market purchases significantly hedged with the financial swap agreement with Generation are also included in the plan under ComEd's procurement plan. The prices resulting from purchases in PJM-administered markets may significantly vary, impacting the total cost to fulfill electricity requirements of ComEd's customers. In order to mitigate the price risk, a portion of the energy price has been locked in through a financial hedge with Generation. In early March 2008, ComEd completed its RFP and the ICC voted to approve the lowest-cost package of bids received as recommended by the procurement administrator. ComEd's purchases acquired through the RFP represent approximately 14% of its expected energy needs from June 2008 through May 2009. Approximately 19% of ComEd's expected energy load, which is purchased on the spot market, for the same period, has been hedged with its variable to fixed financial swap with Generation. The ICC-approved prices reflected in the compliance tariff filing following the ICC's approval of the RFP incorporate the applicable PJM Reliability Pricing Model (RPM) capacity prices. The RFP related to only a portion of ComEd's load requirement beginning in June 2008, the RPM impacts to overall customer electric rates are relatively smaller than those expected in future years. As ComEd's auction contracts expire and a larger portion of power and energy is procured in the future through the RFP procurement process, increases in capacity prices associated with RPM capacity auctions are expected to have a more significant impact to customer electric rates. See Note 9—Derivative Financial Instruments for further discussion on the financial swap derivative.

The ICC has also initiated a proceeding to reconcile 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. Since 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.

On January 7, 2009, the ICC-approved the IPA plan for ComEd's power procurement from June 2009 through May 2010, which includes the remaining supplier forward contracts, standard block energy purchases to be set through an RFP in 2009, spot market purchases hedged with the financial swap with Generation, and any additional spot market purchases needed to service customers. See Note 9—Derivative Financial Instruments for further discussion on the financial swap derivative.

2005 Rate Case. In August 2005, ComEd filed a rate case with the ICC to comprehensively revise its tariffs and to adjust rates for delivering electricity effective January 2007 (2005 Rate Case). ComEd proposed a revenue increase of $317 million. During 2006, the ICC issued various orders associated with this case, which resulted in a total annual rate increase of $83 million effective January 2007. ComEd and various other parties have appealed the rate order to the courts. ComEd cannot predict the results or the timing of the appeal. In the event the order is ultimately changed, the changes are expected to be prospective.

Original Cost Audit. In connection with ComEd's 2005 Rate Case proceeding, the ICC, with ComEd's concurrence, ordered an "original cost" audit of ComEd's distribution assets. In December 2007, the consulting firm that completed the audit presented its findings to the ICC staff regarding accounting methodology, documentation and other matters, along with proposed adjustments. The results of the audit were reported to the ICC in April 2008. The audit report recommended gross plant disallowances of approximately $350 million, before reflecting accumulated depreciation. The basis for the disallowance recommendation on approximately $80 million of the costs was that they were misclassified between ComEd's distribution and transmission operations; ComEd reclassified these costs in September 2007 and they were reflected correctly in ComEd's most recent delivery service rate proceeding.

On April 10, 2008, ComEd and the ICC staff reached a stipulation (the stipulation) regarding various portions of contested issues in the Original Cost Audit as well as the 2007 Rate Case and agreed to make various joint recommendations to the ICC in the 2007 Rate Case. On September 10, 2008, the ICC issued an order in the 2007 Rate Case, more fully described below. The ICC order incorporated the joint recommendations made by ICC Staff and ComEd and required ComEd to incur a charge of approximately $19 million (pre-tax) related to various items identified in the Original Cost Audit.

The ICC opened a proceeding on the Original Cost Audit on May 13, 2008. There is a tentative timeline for resolution of this proceeding during the second half of 2009. Under the terms of the stipulation the ICC Staff will not advocate that any of the proposed adjustments in the audit report be adopted other than those reflected in the 2007 Rate Case; however, the stipulation does not preclude other parties to the rate case or to the Original Cost Audit proceeding from taking positions contrary to the stipulation. On December 19, 2008, the Attorney General submitted testimony suggesting that ComEd improperly changed the way it capitalized cable faults during the rate freeze period and appears to suggest a corresponding reduction to rate base. ComEd believes the remainder of the consulting firm's findings and the testimony of the Illinois Attorney General are without merit. However, the ultimate resolution of the audit after reflecting the appropriate associated accumulated depreciation and deferred income taxes associated with any such disallowances could result in a material disallowance and related write-off of a portion of the original cost of ComEd's delivery system assets.

2007 Rate Case. On October 17, 2007, ComEd filed a rate case with the ICC for approval to increase its delivery service revenue requirement (2007 Rate Case) by approximately $360 million to reflect increased operating costs and ComEd's continued investment in delivery service assets since rates were last determined. The rate filing was based on a 2006 test year and capital additions projected through the third quarter of 2008.

On September 10, 2008, the ICC issued an order in the rate case approving a $274 million increase in ComEd's annual revenue requirement, which became effective on September 16, 2008. The order also incorporated the joint recommendations of the ICC Staff and ComEd in the Original Cost Audit stipulation, including approving recovery of projected capital additions through the second quarter of 2008. Additionally, the ICC order required ComEd to record charges during the third quarter associated with fixed asset disallowances of approximately $37 million (pre-tax), partially offset by the establishment of regulatory assets of approximately of $13 million (pre-tax), for costs that have been previously expensed by ComEd that will be recovered through rates over the next several years, resulting in a net decrease in operating income of $24 million (pre-tax). The disallowance charges included approximately $19 million (pre-tax) of fixed asset disallowances, based on the Original Cost Audit stipulation, and a charge of $18 million (pre-tax) related to the order's disallowance of certain fixed asset costs the ICC indicated were not adequately supported.

The filing also included a system modernization rider, which the ICC approved for the limited purpose of implementing a pilot program for Advanced Metering Infrastructure (AMI). The rider would permit investments in AMI to be reflected in rates on a quarterly basis instead of waiting for the next rate case to begin recovery.

ComEd and several other parties have filed appeals of the rate order with the courts. ComEd cannot predict the timing of resolution or the results of the appeals. In the event the order is ultimately changed, the changes are expected to be prospective.

Transmission Rate Case. In March 2007, ComEd filed a request with the FERC seeking approval to update its transmission rates and change the manner in which such rates are determined from fixed rates to a formula rate. ComEd also requested incentive rate treatment for certain transmission projects. In June 2007, FERC issued an order that conditionally approved ComEd's proposal to implement a formula-based transmission rate effective as of May 1, 2007, subject to refund, hearing procedures and conditions. Effective May 1, 2007, PJM began billing customers based on the conditional FERC order.

In October 2007, ComEd made a filing with FERC seeking approval of a settlement agreement reached by most active parties and opposed by no party in the transmission rate proceeding. FERC approved the settlement agreement on January 16, 2008. The settlement agreement 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. The settlement agreement provides for a base return on equity on transmission rate base of 11.5%, a cap of 58% on the equity component of ComEd's capital structure, which will decline to 55% by 2011, and a debt-only return based on ComEd's long-term cost of debt on ComEd's pension asset. The settlement agreement resulted in a first-year annual transmission network service revenue requirement increase of approximately $93 million. This was a $24 million reduction from the revenue requirement conditionally approved by FERC in its June 5, 2007 order. The formula rate is updated annually to ensure that customers pay the actual costs of providing transmission services. In addition, on January 18, 2008, FERC issued an order on ComEd's request for rehearing on incentive returns that permitted ComEd to include a 1.5% adder to the return on equity for ComEd's largest transmission project, thereby resulting in a 13% return on equity for the project. The order also authorized the inclusion of 100% of construction work in progress in rate base for that project, but

rejected incentive treatment for certain other projects requested by ComEd. The cumulative impact of the above items is an annual revenue requirement of approximately $390 million. On February 19, 2008, several parties filed a petition for rehearing of FERC's January 18, 2008 order. On September 8, 2008, FERC issued an order on rehearing in which it reviewed, and then rejected interveners' arguments on granting incentives and confirmed the result of the order issued on January 18, 2008.

On May 15, 2008, ComEd filed its first annual formula update filing, which updates ComEd's formula rate to include actual 2007 expenses and investment plus forecasted 2008 capital additions. The update resulted in a revenue requirement of $430 million, plus an additional $26 million related to the 2007 true-up of actual costs for a total increase of approximately $66 million, which became effective for the period June 1, 2008 through May 31, 2009. ComEd will continue to reflect its best estimate of its anticipated true-up in the financial statements. As of December 31 2008, ComEd had a regulatory asset associated with the remainder of its 2007 true-up and the estimated effect of the 2008 true-up to be filed in May 2009. The regulatory asset will be amortized as the associated revenues are received.

City of Chicago Settlement Agreement. In December 2007, ComEd entered into a settlement agreement with the City of Chicago regarding a wide range of issues including components of its franchise agreement with the City of Chicago and other matters. Pursuant to the terms of the settlement agreement, ComEd will make payments totaling $55 million to the City of Chicago through 2012 so long as the City of Chicago meets specified conditions contained in the settlement agreement. ComEd has made payments of $18 million and $23 million in 2008 and 2007, respectively. The remaining payments of $8 million, $3 million, $1 million, and $2 million will be made in the years 2009 through 2012, respectively. All payments will be included as a reduction of other revenue in ComEd's statement of operations in the period in which the cash payments are made to the City of Chicago.

The City of Chicago has agreed not to challenge ComEd's position in certain regulatory proceedings during the term of the settlement agreement, including:

- ComEd's proposed revenue requirements in future cases if the projected increase in the average residential bill does not exceed a certain amount based on the Consumer Price Index
- ComEd's recovery of all of its wholesale power costs
- Any rate design or rider filed with the ICC, unless the impact of the challenge on ComEd would be revenue neutral.

Under the settlement agreement, the City of Chicago further agreed to allow ComEd to cancel various projects previously required under a franchise agreement with the City of Chicago and to defer completion of certain other required projects. This settlement agreement also settles other disputes between ComEd and the City of Chicago, including dismissing the City of Chicago's appeal of ComEd's 2005 Rate Case. ComEd and the City of Chicago also agreed to establish a panel of ComEd and the City of Chicago representatives to evaluate opportunities to improve service reliability in the City of Chicago.

Competitive Electric Generation Suppliers. Illinois Senate Bill (SB) 1299, which was enacted into law in November 2007, generally requires utilities to purchase receivables through an ICC tariff from competitive electric generation suppliers for power and energy service provided to the utility's retail customers with a non-coincident peak demand of less than 400 kilowatt (kW). The law expressly provides for the recovery of the reasonable costs associated with the implementation of the law and ongoing costs of purchasing the receivables including the risk of uncollectible accounts. ComEd is not expected to purchase any receivables under the law until the second half of 2009 or later.

Pennsylvania Gas Distribution Rate Case. On March 31, 2008, PECO filed a petition before the PAPUC for a $98 million increase to its distribution revenue to fund critical infrastructure improvement projects that will ensure the safety and reliability of the natural gas delivery system. On August 21, 2008, PECO filed a joint settlement petition with the PAPUC, signaling that it had reached an agreement with the opposing parties regarding the requested distribution rate increase. The settlement petition provided for an annual revenue increase of $77 million. As part of the settlement, PECO will 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. Additionally, PECO agreed not to file a new base rate case for natural gas distribution service before January 1, 2010. On October 23, 2008, the PAPUC voted to approve the joint settlement. The approved rate adjustment became effective on January 1, 2009.

Pennsylvania Transition-Related Legislative and Regulatory Matters. In Pennsylvania, despite the decrease during 2008 in wholesale electricity market prices, there is growing pressure from state regulators and elected officials to mitigate the potential impact of electricity price increases on customers. Experiences in other states following the end of retail electric generation rate cap transition periods created a heightened state of political concern that significant electricity price increases may also occur after the

expiration of rate caps in Pennsylvania. While PECO's retail electric generation rate cap transition period does not end until December 31, 2010, transition periods have ended for six other Pennsylvania electric distribution companies, and, in most instances, post-transition electricity price increases occurred. Over the past two years, elected officials in Pennsylvania have worked on developing legislation to address the Governor's comprehensive energy plan as well as concerns noted above.

On July 9, 2008, the Pennsylvania Legislature passed and the Governor signed legislation, providing a $650 million fund to support investment in renewable power resources and conservation. The fund will be appropriated from Pennsylvania's General Fund.

Also in October 2008, the Pennsylvania General Assembly passed and the Governor signed Act 129 of 2008 (Act 129) into law. This legislation requires that Pennsylvania electric utility companies meet energy-conservation and demand-reduction targets, beginning in 2011, to enhance the Commonwealth's energy independence and enable programs to help manage their energy use. Also, PECO will be required to transition its electric customers to smart-meter technology over a fifteen-year period and to make available time-of-use rates and real-time price plans. The legislation allows recovery of costs for each of these programs, subject to approval by the PAPUC. If PECO were to fail to achieve the required reductions in consumption within stated deadlines, PECO would be subject to civil penalties of up to $20 million. Any penalties paid would not be recoverable from ratepayers. Finally, Act 129 provides guidelines associated with electricity procurement that support competitive, market-based procurement through auctions, requests for proposal or bilateral agreements with a prudent mix of spot market purchases, short-term contracts and long-term (more than four years) purchase contracts.

PECO has engaged the Governor and other Pennsylvania elected officials in negotiations over mitigation, including utility contributions to help offset projected price increases upon the expiration of retail electric generation rate cap transition periods. Measures suggested by officials include rate-cap extensions, rate-increase deferrals and phase-ins, a generation tax and contributions of value (potentially billions of dollars statewide) by Pennsylvania utility companies toward rate-relief programs. Although legislation has been proposed and discussed associated with the mitigation of the potential impacts of electricity price increases upon the ending of retail electric generation rate cap transition periods, no legislation has been passed. The Governor and Legislative leaders have pledged to reexamine possible mitigation measures in the 2009 legislative session.

On March 14, 2008, PECO requested authorization from the PAPUC to begin phase one of a voluntary residential real-time pricing program (RRTP). Available to up to 2,000 PECO customers, the program would allow customers to view the next day's energy prices, learn about how they use energy and potentially save money by reducing energy use during the highest cost hours of the day. A settlement was reached with all parties to the proceeding, and a Joint Petition for approval of the settlement was filed with the PAPUC on August 29, 2008. On October 8, 2008, the presiding administrative law judge (ALJ) issued a recommended decision approving the settlement without modification. On November 24, 2008, the PAPUC issued a Tentative Order directing PECO to: (1) further support; (2) revise; or (3) withdraw its Phase I RRTP proposal and submit a revised proposal as part of its Act 129 filing in July 2009. The PAPUC has developed new energy efficiency program rules to comply with Act 129. Given this development, PECO has withdrawn its Phase I RRTP proposal and intends to refile as part of its obligation to offer RRTP programs under Act 129.

On August 7, 2008, the PAPUC approved the Consumer Education Plan filed by PECO on December 28, 2007 in response to a May 10, 2007 order from the PAPUC. The Plan addressed, among other factors, energy conservation, retail choice, low-income programs and the education of customers about generation charges on their bills that may occur following the rate cap expiration. The education plan will be in effect for at least five years. PECO will receive full and current cost recovery associated with this plan.

On September 10, 2008, PECO filed its comprehensive Default Service Program and Rate Mitigation Plan with the PAPUC seeking approval to provide default electric service following the expiration of electric generation rate caps on December 31, 2010. The filing included: (1) PECO's Default Service Program with competitive, full-requirements energy-supply procurements; (2) a voluntary Early Phase-In Plan allowing customers to pre-pay, with interest, expected post-electric generation rate cap increases; (3) a voluntary deferral phase-in plan allowing customers to phase in rate increases post rate-cap expiration; and (4) an Energy Efficiency Package with energy-efficiency and demand-response programs to help PECO's customers transition from capped electric generation rates to market-priced generation.

The filing included, among other features, tailored procurement strategies for different customer classes using a competitive RFP process, hourly priced default service for large commercial and industrial customers, laddering of multi-year contracts to reduce risks of procurement of default supply at single points in time and a requirement for suppliers to provide Alternative Energy Credits (AECs) for PECO's compliance with the Alternative Energy Portfolio Standards Act (AEPS Act). The filing also included rate mitigation proposals to assist customers with the anticipated price increases, including a prepayment option to permit customers to pay a fixed charge in their current bill that will be applied, with interest, to the customer's future bills in the post-electric generation rate cap

period, and a deferral option to permit customers to phase-in annual increases upon the expiration of PECO's electric generation rate caps, with the unpaid amount due to PECO, with interest, in later years. PECO has requested full and current cost recovery associated with these plans.

The Default Service Program and Rate Mitigation Plan filing was amended on November 14, 2008 to address Act 129. On the same date, PECO filed a Petition for Leave to Withdraw its Market Rate Transition Energy Efficiency Package, with the consent of all parties, in order to determine how the PAPUC's new Act 129 energy efficiency rules will impact energy efficiency programs. The PAPUC will conduct a formal proceeding to give all interested parties the opportunity to examine aspects of the amended filing and make independent recommendations. The process is expected to be completed by July 2009. On January 27, 2009, PECO submitted a settlement reached with the PAPUC staff and government and consumer advocate groups regarding the terms of PECO's Market Rate Transition Phase-In Program. If approved by the PAPUC, beginning on July 2009 PECO will allow eligible residential and small business electric service customers to transition to market-priced generation through pre-payments made in 2009 through 2010 that will accrue interest at regulatory mandated rate of 6% and then be applied to their bills in 2011 through 2012. The settlement also provides for recovery of PECO's consumer education costs through a surcharge and other program costs in PECO's next base rate filing. PECO expects the ALJ's recommended decision on the settlement in February 2009, and the PAPUC's final order in April 2009.

Alternative Energy Portfolio Standards. In November 2004, Pennsylvania adopted the AEPS Act. The AEPS Act mandated that beginning in 2007, or following the end of an electric distribution company's retail electric generation rate cap transition period, certain percentages of electric energy sold by an electric distribution company or electric generation supplier 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 ranges from 1.5% to 8.0% and the Tier II requirement ranges from 4.2% to 10.0%.

On December 20, 2007, the PAPUC approved PECO's plan to acquire and bank up to 450,000 non-solar Tier I AECs (corresponding to the expected annual output of approximately 240 megawatts (MWs) of wind power) annually for a five-year term in order to prepare for 2011, the first year of PECO's required compliance following the completion of its transition period. The banked AECs may be used in either of the two consecutive AEPS reporting periods after PECO's transition period. PECO proposed that all of the costs it incurs in connection with such procurement prior to 2011 be deferred as a regulatory asset with a return on the unamortized balance in accordance with the AEPS Act and will be recovered from customers in 2011. Those costs, and PECO's AEPS Act compliance costs incurred thereafter, would be recovered through a reconcilable ratemaking mechanism as contemplated by the AEPS Act and would be recoverable from customers on a full and current basis. In conformance with the plan approved on December 20, 2007, PECO conducted two RFPs during 2008, commencing in March 2008 and November 2008. Pursuant to the first RFP process, PECO entered into a five-year agreement with an accepted bidder in August 2008. In the November 2008 RFP, PECO again seeks to enter into fixed-price, five-year agreements with qualified bidders to purchase AECs. PECO anticipates entering into the agreements by March 2009, with AEC purchases beginning no later than December 31, 2009.

Pursuant to Act 129, additional energy sources were added to the acceptable alternative energy sources defined in the AEPS Act. Act 129 provides for the acceptance of low-impact hydropower and certain biomass energy as acceptable forms of alternative energy sources. Both low-impact hydropower and certain biomass energy generated within Pennsylvania will be considered Tier I alternative energy sources. Biomass energy generated outside of Pennsylvania will be considered a Tier II alternative energy source. Also, Act 129 provides for quarterly increases in the percentage share of Tier I alternative energy sources required to be sold by electric distribution companies to reflect any new biomass energy or low-impact hydropower resources that qualify as Tier I alternative energy sources. However, no new resources qualifying as biomass energy or low-impact hydropower will be eligible to generate Tier I alternative energy credits until the PAPUC has increased the percentage share of Tier I to reflect these additional resources.

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 July 2006, the ALJ issued an Initial Decision that recommended that FERC implement a new rate design suggested by FERC staff, effective as of April 1, 2006, but also allowed for the potential to phase in rate changes. In April 2007, FERC issued its order on review of the ALJ's decision. FERC held that PJM's current rate design for existing facilities is just and reasonable and should not be changed. That is consistent with Exelon's position in the case. FERC also held that the costs of new facilities should be allocated under a different rate design. FERC held that the costs of new facilities 500 kilovolts (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. FERC stated that PJM's members should develop a standard method for allocating the

costs of new transmission facilities lower than 500 kV. In September 2007, a settlement was reached on most of the issues relating to allocating costs of new transmission facilities lower than 500 kV. FERC's decision on existing facilities leaves the status quo as to existing costs, which is substantially more favorable to Exelon than the ALJ's decision as to existing facilities. In the short term, based on new transmission facilities approved by PJM through December 2008, it is likely that allocating the costs of new 500 kV facilities across PJM will increase charges to ComEd and reduce charges to PECO, as compared to the allocation methodology in effect before the FERC order. On May 21, 2007, Exelon, on behalf of Generation, ComEd, and PECO, and other parties filed requests for rehearing of FERC's April 2007 order. On January 31, 2008, FERC denied rehearing on all issues. Several parties have filed petitions in the United States Court of Appeals for review of the decision. 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 also has the right to file with the PAPUC for a change in retail rates to reflect changes in its wholesale transmission costs. PECO cannot predict the long-term impact of any rate design changes due to the uncertainty as to whether new facilities will be built and how the costs of new facilities less than 500 kV will be allocated; however, the impact may be material to its results of operations, cash flows, or financial position.

PJM-MISO Regional Rate Design. The current PJM-MISO Regional Rate Design is used to specify the pricing of transmission service between PJM and MISO and impacts ComEd and PECO due to purchases by suppliers from the MISO. In August 2007, ComEd and PECO and several other transmission owners in PJM and MISO, as directed by a FERC order issued in November 2004, filed with FERC to continue the existing transmission rate design between PJM and MISO. On August 22, 2007, additional transmission owners and certain other entities filed protests urging FERC to reject the filing. On September 17, 2007, a complaint was filed at FERC asking FERC to find that the PJM-MISO rate design was unjust and unreasonable and to substitute a rate design that socializes the costs of all existing and new transmission facilities of 345 kV and above across PJM and MISO. ComEd and PECO filed a response in October 2007 stating that FERC should dismiss the complaint without a hearing. On January 31, 2008, FERC denied the complaint. On December 19, 2008, FERC denied a request for rehearing of these orders and that action is subject to review in the United States Court of Appeals. ComEd and PECO cannot predict the outcome of this litigation.

Authorized Return on Rate Base. With the end of the transition and rate freeze period, in its December 20, 2006 order, the ICC authorized a return on the 2004 adjusted test year distribution rate base of 8.01% for ComEd starting in 2007. In the September 10, 2008 order in the 2007 Rate Case, 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 previously authorized. As part of the FERC-approved settlement of ComEd's 2007 transmission rate case discussed above, ComEd's formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 9.37% (exclusive of the incentive ROE on the large project discussed above). The weighted average debt and equity return on transmission rate base will be updated annually in accordance with the formula-based rate calculation discussed above.

PECO's transition period includes caps on electric generation rates that will expire on December 31, 2010 pursuant to the Pennsylvania Electric Generation Customer Choice and Competition Act (Competition Act). The distribution and transmission components of PECO's rates will continue to be regulated subsequent to the transition period. PECO's most recently approved weighted average debt and equity return on electric rate base was 11.23% (approved in 1990). PECO's gas rates are not subject to caps. As part of the PECO gas distribution rate case filed on March 31, 2008, PECO requested that the PAPUC authorize it to establish base rates for natural gas distribution service using a weighted average debt and equity return on gas rate base of 8.90%. The joint settlement petition in that matter, approved on October 23, 2008 by the PAPUC, did not specify the rate of return upon which the settlement rates are based, but rather provided for an annual revenue increase without regard to a specific return on gas rate base. Prior to the 2008 gas distribution rate case, the most recently approved weighted average debt equity return on gas rate base was 11.45%, which was approved in 1988.

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 sales of electricity. 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.

In June 2007, FERC issued a Final Rule on Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities (Order No. 697), which updated and modified the tests that FERC had implemented in 2004. That order was clarified on December 14, 2007, largely affirmed on April 21, 2008 in Order No. 697-A, further clarified on July 17, 2008, where

the calculation of one of the variables used in FERC's screening tests was explained and further clarified and largely affirmed on December 19, 2008 in Order No. 697-B. On January 14, 2008, Generation, ComEd and PECO filed an analysis using FERC's updated screening tests, as required by the Final Rule. The filing demonstrated that under those tests, Generation, ComEd, and PECO should be permitted to continue to sell at market-based rates. On April 4, 2008, FERC requested Generation, ComEd and PECO to provide additional information. On August 15, 2008, Generation, ComEd and PECO made an updated filing based on the additional information requested by FERC and following FERC's guidance in its July 17, 2008 order.

On March 12, 2008, the ICC intervened in the proceeding and on September 10, 2008, filed a protest. In its protest, the ICC did not object to Exelon's request for continued authority to make market-based sales. Rather, repeating its contentions in an earlier docket in which ComEd had asked FERC to affirm that ComEd's procurement for its customers for the period June 1, 2008 through May 31, 2009 satisfied FERC standards, the ICC contended that existing waivers of FERC's affiliate transaction rules should no longer apply between ComEd and its affiliates, including Generation, because ComEd has captive retail customers. In its response, Exelon reminded FERC that the ICC's contention was the same as in the earlier ComEd procurement proceeding in which FERC had rejected the ICC's position. Exelon also noted that the facts on which FERC based its previous finding have not changed.

On January 15, 2009, FERC accepted Exelon's analysis and filing, affirming Exelon's affiliates' continued right to make sales at market-based rates. On the same day, it also rejected an ICC request for rehearing in the earlier ComEd procurement docket, in which the ICC had also asked FERC to reconsider its determination in that proceeding that the existing waiver of the affiliate restrictions should not be revoked. Accordingly, the Registrants do not expect that the Final Rule will have a material effect on their results of operations in the short-term. The longer-term impact will depend on the future application by FERC of Order Nos. 697 and future actions involving market-based rates.

Reliability Pricing Model (RPM). On August 31, 2005, PJM submitted a proposal to FERC for a new capacity payment construct to replace PJM's then-existing capacity obligation rules. The proposal provided for a forward capacity procurement auction to establish capacity and payment obligations using a demand curve and locational deliverability zones for capacity. The FERC affirmed PJM's proposal for forward commitments and other matters but encouraged PJM and the parties to that FERC proceeding to resolve other RPM issues by settlement. A settlement was reached on September 29, 2006 and was approved by FERC on December 22, 2006. 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. A number of parties appealed the FERC order approving the settlement, and those appeals have been consolidated and are pending in the United States Court of Appeals for the D.C. Circuit. Because the court did not stay the FERC order pending appellate review, PJM implemented RPM in 2007. Generation believes that it is remote that the ultimate outcome of this appeal will have a material adverse impact on Exelon's or Generation's results of operations, cash flows or financial position.

PJM's four transitional RPM auctions took place in April 2007, July 2007, October 2007 and January 2008 and established prices for the period from June 1, 2007 through May 31, 2011. Subsequent auctions will take place 36 months ahead of the scheduled delivery year. The RPM is anticipated to have a favorable impact for owners of generation facilities, particularly for such facilities located in constrained zones. PJM is authorized to impose PJM RPM capacity penalties. The auction for the delivery year ending May 31, 2012 occurred in May 2008. 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 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. On September 19, 2008, FERC dismissed the complaint finding that no party violated PJM's tariff and the prices determined during the initial auctions implementing the RPM were in accord with the tariff provisions governing the auctions. In a companion order issued the same day, FERC directed PJM and its stakeholders to evaluate whether prospective changes should be made to RPM and if a consensus is reached, file such a consensus with FERC in time to be in effect for the May 2009 RPM Auction. To supplement the record, FERC granted a motion for a technical conference to be held in February 2009. PJM filed a report with FERC on December 12, 2008 summarizing the discussions and explaining that a consensus was not reached. PJM also filed its own proposal with FERC on December 12, 2008. Both orders are subject to rehearing and any decision may then be subject to review in the United States Court of Appeals. If FERC on rehearing or a Federal Court of Appeals were to reverse FERC's decision, FERC would be required to conduct additional proceedings regarding the substantive allegations in the complaint. Generation believes that it is remote that the ultimate outcome of this matter will have a material adverse impact on Exelon's or Generation's results of operations, cash flows or financial position.

License Renewals. In December 2004, the Nuclear Regulatory Commission (NRC) issued an order that will permit the Oyster Creek Generating Station (Oyster Creek) to operate beyond its license expiration in April 2009 if the NRC has not completed reviewing the application for renewal. In July 2005, Generation applied for license renewal for Oyster Creek on a timeline consistent and integrated with the other planned license renewal filings for the Generation nuclear fleet. The application was challenged by various citizen groups and the New Jersey Department of Environmental Protection (NJDEP). The contentions raised by these groups were reviewed and rejected by NRC's Atomic Safety Licensing Board (ASLB). In January 2008, the citizens group appealed the rejection of its contention to the NRC Commissioners. If the NRC Commissioners reject the appeal, the citizens group can further appeal to the Federal courts. The NJDEP appealed to the Third Circuit Court of Appeals one of its rejected contentions asserting that the NRC must consider terrorism risks as part of the re-licensing proceeding. This contention had previously been rejected by the ASLB and the NRC Commissioners. Further, in January 2008, AmerGen received a letter from the NJDEP concluding that Oyster Creek's continued operation is consistent with New Jersey's Coastal Management Program, and approving Oyster Creek's coastal land use plans for the next 20 years. This consistency determination is a necessary element for license renewal. With the NJDEP consistency determination and the rejection of the sole remaining contention by the ASLB, Generation is currently awaiting the Commission's decision on appeal and completion of the NRC staff's consideration of the license renewal for Oyster Creek. The NRC's approval is expected in the first quarter of 2009.

On January 8, 2008, AmerGen submitted an application to the NRC to extend the operating license of Three Mile Island (TMI) Unit 1 for an additional 20 years from the expiration of its current license to April 2034. The NRC is expected to spend up to 30 months to review the application before making a decision. As with Oyster Creek, Generation expects various legal challenges to the renewal application, but ultimately expects approval from the NRC.

The NRC has already approved 20-year renewals of the operating licenses for Generation's Peach Bottom, Dresden and Quad Cities generating stations. The licenses for Peach Bottom Unit 2, Peach Bottom Unit 3, Dresden Unit 2, Dresden Unit 3, Quad Cities Unit 1 and Quad Cities Unit 2 were renewed to 2033, 2034, 2029, 2031, 2032 and 2032, respectively.

4. Accounts Receivable

Accounts receivable at December 31, 2008 and 2007 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:

	2008	2007
Unbilled revenues	$1,199	$1,322
Allowance for uncollectible accounts	(238)	(130)

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 PECO accounted for as a sale under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities—a Replacement of FASB Statement No. 125," (SFAS No. 140). PECO retains the servicing responsibility for the sold receivables and has recorded a servicing liability in accordance with FASB Statement No. 156, "Accounting for Servicing of Financial Assets, an amendment of FASB Statement No. 140." The agreement terminates on September 18, 2009 unless extended in accordance with its terms. As of December 31, 2008, PECO is in compliance with the requirements of the agreement. See Note 16—Fair Value of Financial Assets and Liabilities for additional information regarding the servicing liability.

5. Property, Plant and Equipment

Exelon

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2008 and 2007:

Asset Category	Average Service Life (years)	2008	2007
Electric—transmission and distribution	5-75	$18,509	$17,361
Electric—generation	2-59	9,108	8,583
Gas—transportation and distribution	5-66	1,631	1,583
Common—electric and gas	5-50	496	469
Nuclear fuel [(a)]	1-8	2,811	2,444
Construction work in progress	N/A	1,038	1,115
Other property, plant and equipment [(b)]	5-72	462	409
Total property, plant and equipment		34,055	31,964
Less: accumulated depreciation [(c)]		8,242	7,811
Property, plant and equipment, net		$25,813	$24,153

(a) Includes nuclear fuel that is in the fabrication and installation phase of $490 million and $376 million at December 31, 2008 and 2007, respectively.

(b) Includes Generation's buildings under capital lease with a net carrying value of $31 million and $34 million at December 31, 2008 and 2007, respectively. The original cost basis of the buildings was $53 million and total accumulated amortization was $22 million and $19 million as of December 31, 2008 and 2007, respectively. Also includes unregulated property at ComEd and PECO.

(c) Includes accumulated depreciation related to regulated property at ComEd and PECO of $4,205 million and $3,962 million as of December 31, 2008 and 2007, respectively. Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $1,214 million and $1,175 million as of December 31, 2008 and 2007, respectively.

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	2008	2007	2006
Electric—transmission and distribution	2.44%	2.39%	2.38%
Electric—generation	3.13%	3.22%	3.21%
Gas	1.73%	1.70%	1.72%
Common—electric and gas	6.94%	6.46%	8.24%

See Note 1—Significant Accounting Polices for further information regarding property, plant and equipment policies and accounting for capitalized software costs. See Note 10—Debt and Credit Agreements for further information regarding property, plant and equipment subject to mortgage liens.

6. Jointly Owned Electric Utility Plant

Exelon's, Generation's and PECO's undivided ownership interests in jointly owned electric plants at December 31, 2008 and 2007 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
Operator	Generation	Generation	PSEG Nuclear	Reliant	Reliant	FP&L	First Energy	PSG&E	[d]
Ownership interest	75.00%	50.00%	42.59%	20.99%	20.72%	5.89%	22.00%	42.55%	44.24%
Exelon's share at December 31, 2008:									
Plant	$ 512	$ 490	$ 379	$ 192	$ 233	$ 2	$ 5	$ 60	$ 1
Accumulated depreciation	85	256	73	114	148	1	4	27	—
Construction work in progress	60	21	37	107	2	1	—	—	—
Exelon's share at December 31, 2007:									
Plant	$ 460	$ 474	$ 244	$ 193	$ 223	$ 2	$ 5	$ 56	$ 1
Accumulated depreciation	77	247	66	113	145	1	4	26	—
Construction work in progress	40	16	103	32	2	—	—	—	—

(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, 2008 and 2007.
(b) PECO owns a 22.00% share in 127 miles of 500,000 voltage lines located in Pennsylvania.
(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 in operating and maintenance expenses on PECO's Consolidated Statements of Operations.

7. Intangible Assets

Goodwill

Pursuant to SFAS No. 142, 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 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.

Exelon assesses goodwill impairment at its ComEd reporting unit. Accordingly, any goodwill impairment charge at ComEd will affect Exelon's consolidated results of operations. In estimating the fair value of ComEd, Exelon and ComEd used a probability-weighted, discounted cash flow model with multiple scenarios. The model included an estimate of ComEd's terminal value based on these expected cash flows and on an earnings multiple approach, which reflected the estimated value of comparable utility companies. The determination of the fair value was also dependent on many sensitive, interrelated and uncertain variables including changing interest rates, utility sector market performance, capital structure, rate regulatory structures, operating and capital expenditure requirements, fair value of debt and other factors. This approach, including the comparable utility companies used to determine the earnings multiple, has been consistently applied since the adoption of SFAS No. 142. In addition, ComEd performed two alternative analyses to corroborate the estimated fair value. The regulatory environment such as the September 2008 Rate Order has provided

more certainty related to ComEd's future cash flows. However, the recent economic downturn and the capital and credit market crisis have impacted the market-related assumptions resulting in a significant decrease in estimated fair value of ComEd since the November 1, 2007 assessment. For example, the earnings multiple used to determine the terminal value decreased from 8.6x at November 1, 2007 to 7.5x at November 1, 2008. While ComEd did not recognize an impairment in 2008, further deterioration of the market related factors used in the impairment review could possibly result in a future impairment loss of ComEd's goodwill, which could be material.

The changes in the carrying amount of goodwill for the years ended December 31, 2008 and 2007 were as follows:

Balance as of January 1, 2007	$2,694
Resolution of certain tax matters [(a)]	(69)
Balance as of December 31, 2007	$2,625

(a) Includes resolution of certain tax matters and the impact of adopting FIN 48 for uncertain tax positions of ComEd that existed at October 20, 2000, the date of the merger in which Exelon became the parent corporation of PECO and ComEd (PECO / Unicom merger), in accordance with EITF Issue No. 93-7, "Uncertainties Related to Income Taxes in a Purchase Business Combination" (EITF 93-7). See Note 1—Significant Accounting Policies and Note 11—Income Taxes for additional information.

During 2008, ComEd had no changes in the carrying amount of goodwill. As of December 31, 2008, ComEd's carrying amount was $2,625 million.

2007 Annual Goodwill Impairment Assessment. The 2007 annual goodwill impairment assessment was performed as of November 1, 2007. 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.

2006 Annual Goodwill Impairment Assessment. The 2006 annual goodwill impairment assessment was performed as of November 1, 2006. 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.

2006 Interim Goodwill Impairment Assessment. Due to the significant negative impact of the ICC's July 2006 order in ComEd's 2005 Rate Case to the cash flows and value of ComEd, an interim impairment assessment was completed during the third quarter of 2006. Based on the results of this interim goodwill impairment analysis, which was performed using the same model and assumptions discussed above, Exelon and ComEd recorded a charge of $776 million associated with the impairment of goodwill during the third quarter 2006.

Other Intangible Assets

Exelon's and ComEd's other intangible assets, included in deferred debits and other assets in the balance sheet, consisted of the following as of December 31, 2008:

				Estimated amortization expense				
	Gross	Accumulated Amortization	Net	2009	2010	2011	2012	2013
Chicago settlement—1999 agreement [(a)]	$100	$(58)	$42	$3	$3	$3	$3	$3
Chicago settlement—2003 agreement [(b)]	62	(21)	41	4	4	4	4	4
Total intangible assets	$162	$(79)	$83	$7	$7	$7	$7	$7

(a) On March 22, 1999, ComEd entered into a settlement agreement with the City of Chicago to end an arbitration proceeding between ComEd and the City of Chicago regarding the franchise agreement and a supplemental agreement, whereby ComEd agreed to make payments of $25 million 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 relative to our ability to distribute electricity in the City of Chicago. The franchise agreement ends in 2020.

(b) On February 20, 2003, ComEd entered into separate agreements with the City of Chicago and with 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, and, among other things, be relieved of a requirement, originally transferred to

Midwest Generation upon the sale of ComEd's fossil plants in 1999, to build a 500 MW generation facility in the City of Chicago. As required by the settlement, ComEd also made a payment of $2.3 million to a third party on the City of Chicago's behalf. The intangible asset recognized as a result of the settlement agreement is being amortized ratably over the remaining term of the franchise agreement relative to our ability to distribute electricity in the City of Chicago. The franchise agreement ends in 2020.

Pursuant to the agreement discussed above, ComEd received payments of $32 million from Midwest Generation to relieve Midwest Generation's obligation under the fossil sale agreement to build the generation facility in the City of Chicago. The payments received by ComEd are being recognized ratably (approximately $2 million annually) as an offset to amortization expense over the remaining term of the franchise agreement relative to our ability to distribute electricity in the City of Chicago.

For each of the years ended December 31, 2008 and 2007, Exelon's and ComEd's amortization expense related to intangible assets was $7 million.

In the second quarter of 2006, Exelon recorded an impairment charge of $115 million (pre-tax) associated with the full write-off of an intangible asset related to its investment in synthetic fuel-producing facilities. For the year ended December 31, 2006, Exelon's and ComEd's amortization expense related to intangible assets was $33 million and $7 million, respectively.

8. Fair Value of Financial Assets and Liabilities

Non-Derivative Financial Assets and Liabilities. As of December 31, 2008 and 2007, 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.

The carrying amounts and fair values of Exelon's long-term debt and spent nuclear fuel obligations as of December 31, 2008 and 2007 were as follows:

	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$11,426	$10,803	$10,520	$10,361
Long-term debt to ComEd Transitional Funding Trust and PETT (including amounts due within one year) [b]	1,124	1,193	2,006	2,079
Long-term debt to other financing trusts	390	200	545	490
Spent nuclear fuel obligation	1,015	544	[a]	[a]
Preferred securities of subsidiaries	87	63	87	70

(a) At December 31, 2007, the carrying value of Exelon's and Generation's spent nuclear fuel obligation was considered to approximate its fair value since, under SFAS No. 107, "Disclosures about Fair Value of Financial Instruments" (SFAS No. 107), entities were permitted to value financial liabilities for which quoted market prices are not available using a settlement rate notion. With the adoption of SFAS No. 157 effective January 1, 2008, a transfer price (or exit price) notion is now required.

(b) As of December 31, 2008, all of ComEd Transitional Funding Trust's debt was retired.

Fair values for 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 spent nuclear fuel (SNF) obligation resulted from contracts with the Department of Energy (DOE) to provide for disposal of SNF from its 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 maturing in 2020 (after being adjusted for Generation's credit risk).

Adoption of SFAS No. 157

Effective January 1, 2008, the Registrants partially adopted SFAS No. 157, which primarily requires expanded disclosure for assets and liabilities recorded on the balance sheet at fair value. As permitted by FSP FAS 157-2, the Registrants have elected to defer the adoption of the nonrecurring fair value measurement disclosures of nonfinancial assets and liabilities, such as goodwill and asset retirement obligations until January 1, 2009. The partial adoption of SFAS No. 157 did not have a material impact on the Registrants' results of operations, cash flows or financial positions.

To increase consistency and comparability in fair value measurements, SFAS No. 157 establishes 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 asset 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-exchanged-based derivatives, commingled investments funds not subject to purchase and sale restrictions 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 and commingled investment funds subject to purchase and sale restrictions.

Recurring Fair Value Measurements

The following table presents 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, 2008:

(In millions)	Level 1	Level 2	Level 3	Balance as of December 31, 2008
Assets				
Cash equivalents	$1,228	$ —	$ —	$1,228
Nuclear decommissioning trust fund investments	1,341	3,076	1,220	5,637 [(a)]
Rabbi trust investments	45	—	—	45 [(b)]
Mark-to-market derivative net assets	12	561	106	679 [(c)(d)]
Total assets	$2,626	$3,637	$1,326	$7,589
Liabilities				
Deferred compensation	—	(85)	—	(85)
Servicing liability	—	—	(2)	(2)
Total liabilities	—	(85)	(2)	(87)
Total net assets	$2,626	$3,552	$1,324	$7,502

(a) Excludes net liabilities of $137 million consisting of payables related to pending securities purchases net of cash, interest receivables and receivables related to pending securities sales.

(b) Excludes $19 million of the cash surrender value of life insurance investments.

(c) Includes both current and noncurrent mark-to-market derivative assets and interest rate swaps, and is net of current and noncurrent mark-to-market derivative liabilities. In addition, the Level 3 balance does not include the current and noncurrent asset of $111 million and $345 million, respectively, related to the fair value of Generation's financial swap contract with ComEd since, at Exelon, these fair value balances are eliminated upon consolidation.

(d) Includes collateral postings received from and paid to counterparties. Collateral received from counterparties, net of collateral paid to counterparties, totaled $11 million, $741 million and $1 million that are netted against Level 1, Level 2 and Level 3 mark-to-market derivative net assets, respectively, as of December 31, 2008.

The following table presents the fair value reconciliation of Level 3 assets measured at fair value on a recurring basis during the year ended December 31, 2008:

Year ended December 31, 2008 (In millions)	Nuclear decommissioning trust fund investments	Mark-to-market derivatives	Servicing Liability	Total
Balance as of January 1, 2008	$2,019	$ 52	$ (1)	$2,070
Total realized / unrealized (losses) gains				
Included in net income	(321)	35 [a]	(1)	(287)
Included in other comprehensive income	—	(33) [b]	—	(33)
Included in regulatory liabilities	(553)	—	—	(553)
Purchases, sales and issuances, net	109	—	—	109
Transfers into (out of) Level 3	(34)	52	—	18
Balance as of December 31, 2008	$1,220	$106	$ (2)	$1,324
The amount of total gains (losses) included in net income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2008	$ (310)	$125	$—	$ (185)

(a) Includes the reclassification of $90 million of realized losses due to the settlement of derivative contracts recorded in results of operations.

(b) Excludes $888 million of changes in the fair value and $24 million of realized gains due to settlements during 2008 of Generation's financial swap contract with ComEd since, at Exelon, these balances are eliminated upon consolidation.

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 year ended December 31, 2008:

(In millions)	Operating Revenue	Purchased Power	Fuel	Other, net
Total gains (losses) included in net income for the year ended December 31, 2008	$ 63	$(12)	$(16)	$(321)
Change in the unrealized gains (losses) relating to assets and liabilities held as of the year ended December 31, 2008	$107	$(34)	$ 52	$(310)

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 table 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. The trust fund investments have been established to satisfy Exelon's and Generation's nuclear decommissioning obligations. The nuclear decommissioning trust 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. These policies restrict the trust funds from holding alternative investments and limit the trust funds' exposures to investments in highly illiquid markets.

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. For fixed income securities, the trustees receive multiple prices from pricing services, which enable cross-provider validations by the trustees 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 trustees challenge an assigned price and 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.

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. 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 all actively traded securities due to the volume trading requirements imposed by these exchanges. In addition, 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 of similar securities, adjusted for observable differences and are categorized in 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, vintage, purpose of loan, collateral attributes, prepayment speeds, interest rates and credit ratings in order to properly value these securities. 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. However, because these short-term commingled funds are only offered to a limited group of investors and, therefore, not exchanged in an active market, they are categorized in Level 2 in the fair value hierarchy. The objectives of the remaining commingled funds in which Exelon and Generation invest primarily seek to track the performance of specific equity indices, specifically the Standard & Poor's (S&P) 500, the Russell 3000 and the Morgan Stanley Capital International EAFE indices, by purchasing equity securities to replicate the capitalization and characteristics of the indices. The fair value of these commingled funds primarily are based on net asset values per fund share (the unit of account), derived from the quoted prices in active markets of the underlying equity securities. However, because the shares of these commingled funds are not publicly quoted, not traded in an active market and are subject to certain restrictions regarding their purchase and sale, the commingled funds are categorized in Level 3. See "Fair Value Option for Financial Assets and Liabilities" in Note 12—Asset Retirement Obligations for further discussion on the nuclear decommissioning trust fund investments.

Rabbi Trust Investments. The Registrants' rabbi trust investments 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 Registrants' rabbi trust investments are included in investments in the Registrants' Consolidated Balance Sheets. The rabbi trust investments shown in the fair value table are comprised of 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.

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 Generation believes provide the most liquid market for the commodity. Generation reviews and corroborates the price quotations to ensure the prices are observable which includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. Generation's non-exchange-based derivatives are predominately at liquid trading points. 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. 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. In instances where observable data is unavailable, Generation considers 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. Generation considers 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. The impacts of credit and nonperformance risk were not material to the financial statements.

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. 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 sold an undivided interest, adjusted daily, in up to $225 million of designated accounts receivable. A servicing liability was recorded for the agreement in accordance with SFAS No. 156. The servicing liability is included in other current liabilities in Exelon's and PECO's Consolidated Balance Sheets. The fair value of the liability has been determined using internal estimates based on provisions in the agreement, which are categorized as Level 3 inputs in the fair value hierarchy. See Note 18—Commitments and Contingencies for further discussion on the accounts receivable agreement.

9. Derivative Financial Instruments

The Registrants utilize derivative instruments to manage exposures to a number of market risks, including changes in interest rates and the impact of market fluctuations in the price of electricity, coal, natural gas, other commodities and other energy-related products marketed and purchased as a result of their ownership of energy-related assets. Additionally, Generation enters into energy-related derivatives for proprietary trading purposes. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a very small portion of Generation's overall energy marketing activities.

Interest-Rate Swaps

The Registrants may utilize fixed-to-floating interest-rate swaps, which are typically designated as fair-value hedges, as a means to achieve their 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, which are typically designated as cash-flow hedges.

Fair-Value Hedges. At December 31, 2008 and 2007, Exelon had $100 million of notional amounts of fair-value hedges outstanding related to interest rate swaps, with fair values of $17 million and $4 million, respectively. During the year ended December 31, 2008 and 2007, there was no impact on the results of operations as a result of ineffectiveness from fair-value hedges.

Cash-Flow Hedges. At December 31, 2008 and 2007, the Registrants did not have any interest rate swaps designated as cash-flow hedges outstanding.

Energy-Related Derivatives

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 assessment of the market, weather, operational and other factors. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Under the provisions of SFAS No. 133, the economic hedges are recognized on the balance sheet at their fair value unless they qualify for the normal purchases or normal sales exception. 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 the value of the underlying exposure is deferred in accumulated other comprehensive income (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.

The contracts that Generation has entered into with ComEd and that ComEd has entered into with Generation and other suppliers as part of the initial ComEd power procurement auction and the RFP which is further discussed in Note 3—Regulatory Issues, qualify for the normal purchases and normal sales exception to SFAS No. 133. Generation and ComEd believe these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. PECO has entered into derivative natural gas contracts to hedge its long-term price risk in the natural gas market. All of PECO's natural gas supply agreements that are derivatives qualify for the normal purchases and normal sales exception to SFAS No. 133. In addition, Generation and PECO have entered into a long-term full requirements power purchase agreement (PPA) under which PECO obtains all of its electric supply from Generation through 2010. The PPA is not considered a derivative under SFAS No. 133.

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 Risk Management Committee. The proprietary trading activities, which included volumes of 8,891 gigawatt hours (GWhs) and 20,323 GWhs for the years ended December 31, 2008 and 2007, respectively, are a complement to Generation's energy marketing portfolio but represent a very small portion of Generation's revenue from energy marketing activities. Neither ComEd nor PECO enter into derivatives for proprietary trading purposes.

The following table provides a summary of the fair value balances recorded by Exelon, Generation and ComEd as of December 31, 2008:

	Generation					ComEd	Other		Exelon
Derivatives	Cash-Flow Hedges [a]	Other Derivatives	Proprietary Trading	Netting [b]	Subtotal [c]	IL Settlement Swap [a]	Other Derivatives	Inter-company Eliminations [a]	Total Derivatives
Current assets	$ 533	$ 165	$ 119	$(296)	$ 521	$ —	$—	$(111)	$ 410
Noncurrent assets	666	198	32	(61)	835	—	17	(345)	507
Total mark-to-market derivative assets	$1,199	$ 363	$ 151	$(357)	$1,356	$ —	$ 17	$(456)	$ 917
Current liabilities	$ (2)	$(372)	$(136)	$ 296	$ (214)	$(111)	$—	$ 111	$(214)
Noncurrent liabilities	—	(37)	(48)	61	(24)	(345)	—	345	(24)
Total mark-to-market derivative liabilities	$ (2)	$(409)	$(184)	$ 357	$ (238)	$(456)	$—	$ 456	$(238)
Total mark-to-market derivative net assets (liabilities)	$1,197	$ (46)	$ (33)	$ —	$1,118	$(456)	$ 17	$ —	$ 679

(a) Includes current and noncurrent asset for Generation and current and noncurrent liability for ComEd of $111 million and $345 million, respectively, related to the fair value of Generation's and ComEd's five-year financial swap contract, as described below under "Illinois Settlement Swap Contract". At Exelon, the fair value balances are eliminated upon consolidation.

(b) Represents the netting of fair value balances with the same counterparty between cash-flow hedges, other derivatives and proprietary trading. See Note 1—New Accounting Pronouncements for further information.

(c) In accordance with FSP FIN 39-1, current and noncurrent assets are shown net of collateral of $177 million and $252 million, respectively, and current and noncurrent liabilities are shown net of collateral of $274 million and $50 million, respectively. The total cash collateral received net of cash collateral posted was $753 million at December 31, 2008.

The following table provides a summary of the fair value balances recorded by Exelon, Generation and ComEd as of December 31, 2007:

	Generation					ComEd	Other		Exelon
Derivatives	Cash-Flow Hedges [a]	Other Derivatives	Proprietary Trading	Netting [b]	Subtotal [c]	IL Settlement Swap [a]	Other Derivatives	Inter-company Eliminations [a]	Total Derivatives
Current assets	$ 37	$ 110	$123	$(23)	$ 247	$ 13	$—	$ (13)	$ 247
Noncurrent assets	—	59	12	(20)	51	443	4	(443)	55
Total mark-to-market derivative assets	$ 37	$ 169	$135	$(43)	$ 298	$456	$ 4	$(456)	$ 302
Current liabilities	$(146)	$ (90)	$ (34)	$ 23	$(247)	$—	$—	$ 13	$(234)
Noncurrent liabilities	(677)	(81)	(3)	$ 20	(741)	—	—	443	(298)
Total mark-to-market derivative liabilities	$(823)	$(171)	$ (37)	$ 43	$(988)	$—	$—	$ 456	$(532)
Total mark-to-market derivative net (liabilities) assets	$(786)	$ (2)	$ 98	$—	$(690)	$456	$ 4	$ —	$(230)

(a) Includes current and noncurrent liability for Generation and current and noncurrent asset for ComEd of $13 million and $443 million, respectively, related to the fair value of Generation's and ComEd's five-year financial swap contract, as described below under "Illinois Settlement Swap Contract". At Exelon, the fair value balances are eliminated upon consolidation.

(b) Represents the netting of fair value balances with the same counterparty between cash-flow hedges, other derivatives and proprietary trading. See Note 1—New Accounting Pronouncements for further information.

(c) In accordance with FSP FIN 39-1, current and noncurrent assets are shown net of collateral of $104 million and $23 million, respectively, and current and noncurrent liabilities are shown net of collateral of $63 million and $82 million, respectively. The total cash collateral posted net of cash collateral received was $272 million at December 31, 2007.

Illinois Settlement Financial Swap Contract. 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 dovetail with ComEd's remaining auction contracts for energy. The swap contract volumes are 1,000 MW for the period extending June 2008 through May 2009, 2,000 MW for the period extending June 2009 through May 2010 and 3,000 MW from June 2010 through May 2013. The terms of the financial swap contract require Generation to pay the market price for the 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 and 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 in rates, and the change in fair value each period is recorded by ComEd as a regulatory asset or liability. As of December 31, 2008 and December 31, 2007, respectively, Generation recorded current and noncurrent mark-to-market derivative assets of $456 million and current and noncurrent mark-to-market derivative liabilities of $456 million. ComEd recorded a regulatory asset of $456 million related to its mark-to-market derivative liability position as of December 31, 2008 and a regulatory liability of $456 million related to its mark-to-market derivative asset position as of December 31, 2007. See Note 3—Regulatory Issues for additional information regarding the Illinois Settlement financial swap contract. In Exelon's consolidated financial statements, all financial statement effects of the swap recorded by Generation and ComEd are eliminated.

Cash-Flow Hedges. Economic hedges that qualify as cash-flow hedges primarily consist of forward power sales and power swaps. At December 31, 2008, Generation had net unrealized pre-tax gains on effective cash-flow hedges of $1,419 million being deferred within accumulated OCI, including approximately $456 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, depending on the commodities

involved in the hedged transaction. Based on market prices at December 31, 2008, approximately $665 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 $111 million related to the financial swap with ComEd. 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 will occur during 2009 through 2011, and the ComEd financial swap contract during 2009 through 2013. In Exelon's consolidated financial statements, all financial statement effects of the swap recorded by Generation and ComEd are eliminated.

The table below provides the activity of accumulated OCI related to cash-flow hedges for the year ended December 31, 2007 to December 31, 2008, 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	ComEd	Exelon
	Energy-Related Hedges	Energy-Related Hedges	Total Cash-Flow Hedges
Accumulated OCI derivative gain (loss) at January 1, 2007	$ 247	$ (4)	$ 243
Effective portion of changes in fair value	(786) [b]	1	(507)
Reclassifications from accumulated OCI to net income	(9)	3	(6)
Accumulated OCI derivative gain (loss) at December 31, 2007	$ (548) [a]	$—	$(270)
Effective portion of changes in fair value	1,075 [b]	—	541
Reclassifications from accumulated OCI to net income	328 [c]	—	314
Accumulated OCI derivative gain (loss) at December 31, 2008	$ 855 [a]	$—	$ 585

(a) Includes $275 million gain and $275 million loss, net of taxes, related to the fair value of the five-year financial swap contract with ComEd for 2008 and 2007 respectively.

(b) Includes $535 million gain and $275 million loss, net of taxes, of the effective portion of changes in fair value of the five-year financial swap contract with ComEd for the year ended December 31, 2008 and 2007 respectively.

(c) Includes $15 million gain, net of taxes, of reclassifications from accumulated OCI to net income related to the settlements of the five-year financial swap contract with ComEd for the year ended December 31, 2008.

During the years ended December 31, 2008, 2007 and 2006, Generation's cash-flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $(544) million pre-tax loss, a $15 million pre-tax gain and a $146 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.

During the year ended December 31, 2008, cash-flow hedge ineffectiveness changed by $44 million due primarily to the decline in market prices during the period, of which none was related to Generation's financial swap contract with ComEd. At December 31, 2008, cash flow ineffectiveness resulted in an adjustment of $15 million to accumulated OCI on the balance sheet in order to reflect the effective portion of derivative gains or losses. During the year ended December 31, 2007, cash-flow hedge ineffectiveness resulted in a $29 million reclassification from accumulated OCI into earnings. During the year ended December 31, 2006 the amount reclassified from accumulated OCI into earnings as a result of ineffectiveness was not material to the financial statements.

ComEd had no cash-flow hedge activity impact to pre-tax income based on the reclassification adjustment from accumulated OCI to results of operations for the year ended December 31, 2008. ComEd's cash-flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $4 million pre-tax loss for the year ended December 31, 2007.

Exelon's cash-flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a ($521) million pre-tax (loss) and $10 million pre-tax gain for the years ended December 31, 2008 and December 31, 2007, respectively. During the year ended December 31, 2008, cash-flow hedge ineffectiveness increased by $44 million due primarily to the decline in market prices during the period.

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 or it is no longer probable that the forecasted transaction will occur. Exelon has not discontinued hedge accounting prospectively for the year ended December 31, 2008.

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, 2008, 2007 and 2006, the following net pre-tax mark-to-market gains (losses) relating to changes in the fair values of certain purchase power and sale contracts pursuant to SFAS No. 133 were reported in fuel and purchased power expense, revenue, and operating and maintenance expense at Generation, ComEd and Exelon Corporate, respectively, in the Consolidated Statements of Operations and in net realized and unrealized mark-to-market transactions in the Consolidated Statements of Cash Flows.

Year Ended December 31, 2008	
Unrealized mark-to-market gains	$495
Realized mark-to-market losses	(88)
Total net mark-to-market gains	$407

Year Ended December 31, 2007	Exelon
Unrealized mark-to-market losses	$ (42)
Realized mark-to-market (losses) gains	(70)
Total net mark-to-market (losses) gains	$(112)

Year Ended December 31, 2006	Exelon
Unrealized mark-to-market gains (losses)	$ 6
Realized mark-to-market gains	77
Total net mark-to-market gains (losses)	$83

Proprietary Trading Activities. For the years ended December 31, 2008 and 2007, 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 revenue in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in net realized and unrealized mark-to-market transactions in Exelon's and Generation's Consolidated Statements of Cash Flows.

	For the Year Ended December 31,		
	2008	2007	2006
Unrealized mark-to-market gains	$106	$42	$ 14
Realized mark-to-market losses	(43)	(8)	(10)
Total net mark-to-market gains	$ 63	$34	$ 4

Credit Risk Associated with Derivative Instruments

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 allows 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.

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 agreements is mitigated by its ability to recover its natural gas costs through the PAPUC purchased gas cost clause that allows PECO to adjust rates to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply agreements.

Collateral Provisions of Illinois Contracts. Beginning in 2007, under the Illinois auction rules and the supplier forward contracts that ComEd entered into with counterparty suppliers, including Generation, collateral postings are only one-sided from suppliers. Generation entered into similar supplier forward contracts with Ameren, with one-sided collateral postings only from Generation. If market prices fall below ComEd's or Ameren's benchmark price levels, ComEd or Ameren are not required to post collateral; however, when market prices rise above benchmark price levels with ComEd or Ameren, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of the five-year financial swap contract between Generation and ComEd, there are no immediate collateral provisions on either party. However, the swap contract also provides that: (1) if ComEd is upgraded to investment grade by Moody's Investor Service or Standard & Poor's (S&P) and then is later downgraded below investment grade, or (2) if Generation is downgraded below investment grade by Moody's Investor Service or S&P, collateral postings would be required by the applicable party depending on how market prices compare to the benchmark price levels. As of December 31, 2008, there was no cash collateral or letters of credit posted between suppliers, including Generation, and ComEd, under any of the above-mentioned contracts.

As of March 19, 2008, ComEd was upgraded to investment grade by S&P, and therefore, the above condition has been satisfied such that if ComEd is later downgraded, it could be subject to collateral requirements depending on market prices at that time. Under no circumstances would collateral postings exceed $200 million from either ComEd or Generation under the swap contract. The Illinois Settlement established a new procurement process that utilizes a pay as bid RFP mechanism in place of the procurement auctions. Generation participated in the 2008 ComEd RFP procurement process and was awarded certain contracts under the RFP. Under the terms of the RFP, collateral postings are required from both ComEd and the counterparty supplier, including Generation, should exposures between market prices and contracted prices exceed established credit thresholds outlined in the agreement. As stipulated in the Illinois legislation as well as the ICC-approved procurement tariff, ComEd is permitted to recover its costs of procuring power and energy plus any prudent costs in arranging and providing for the supply of electric power and energy. Therefore all costs associated with collateral postings are recoverable from retail customers through ComEd's procurement tariff. See Note 3—Regulatory Issues for further information.

Accounting for the Offsetting of Amounts Related to Certain Contracts

Exelon and Generation adopted the provisions of FSP FIN 39-1 on January 1, 2008. As a result of the adoption, Exelon and Generation record cash flow hedges and other derivative and proprietary trading activities in the balance sheet on a net basis and offset the fair value amounts recognized for energy-related derivatives with cash collateral paid to or received from counterparties under master netting arrangements.

Exelon and Generation retrospectively reclassified certain assets and liabilities in accordance with FIN 39, as amended by FSP FIN 39-1, and the following table shows the effect on Exelon's and Generation's Consolidated Balance Sheets as of December 31, 2007.

	Generation			Exelon		
	As Previously Stated	FIN 39 and FSP FIN 39-1 Adjustments	As Adjusted	As Previously Stated	FIN 39 and FSP FIN 39-1 Adjustments	As Adjusted
Mark-to-market derivative current assets	$445	$(198)	$247	$445	$(198)	$247
Prepayments and other current assets	552	(273)	279	700	(273)	427
Mark-to-market derivative noncurrent assets	113	(62)	51	117	(62)	55
Mark-to-market derivative current liabilities	599	(365)	234	599	(365)	234
Other current liabilities	261	(1)	260	984	(1)	983
Mark-to-market derivatives noncurrent liabilities	465	(167)	298	465	(167)	298

As of December 31, 2008 and December 31, 2007, $5 million and $1 million, respectively, of cash collateral received was not offset against net derivative positions, because 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 and ComEd meets its short-term liquidity requirements primarily through borrowings under its credit facility.

As of December 31, 2008, Exelon Corporate, Generation, ComEd and PECO had access to unsecured revolving credit facilities with aggregate bank commitments of $957 million, $4.8 billion, $952 million and $574 million, respectively. During the third quarter of 2008, the Registrants were notified by Lehman Brothers Bank that it would not be able to fund its commitments under the Registrants' credit agreements. The commitment of Lehman Brothers Bank was terminated effective September 30, 2008, and the amounts of the credit agreements with Lehman Bank are not included in the amounts above. Prior to termination, Lehman Brothers Bank's total commitment within these credit facilities was $283 million, of which Exelon Corporate, Generation, ComEd and PECO had $43 million, $166 million, $48 million and $26 million, respectively.

Exelon, Generation, ComEd and PECO had the following amounts of commercial paper and credit facility borrowings outstanding at December 31, 2008 and December 31, 2007:

Commercial Paper Issuer	Maximum Program Size at December 31, 2008 [(a)]	Maximum Program Size at December 31, 2007 [(a)]	Outstanding Commercial Paper at December 31, 2008	Outstanding Commercial Paper at December 31, 2007
Exelon Corporate	$ 957	$1,000	$ 56	$ —
Generation	4,834	5,000	—	—
ComEd [(b)]	952	1,000	—	—
PECO	574	600	95	246

(a) Equals aggregate bank commitments under revolving credit agreements.
(b) During 2008, ComEd was unable to access the commercial paper market given the market environment.

Credit facility borrowings	December 31, 2008	December 31, 2007
ComEd	$60	$370

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, each 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 2008, 2007 and 2006:

	2008	2007	2006
Average borrowings	$ 636	$ 500	$ 856
Maximum borrowings outstanding	1,646	1,210	1,459
Average interest rates, computed on a daily basis	3.22%	5.55%	5.02%
Average interest rates, at December 31	0.93%	5.44%	5.42%

Credit Agreements

As of December 31, 2008, 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.

As of December 31, 2008, ComEd had access to an unsecured credit facility with aggregate bank commitments of $952 million. ComEd's unsecured facility expires February 16, 2011 unless extended in accordance with its terms. Under its credit facility, ComEd

may request up to a two one-year extensions of that term. ComEd may also request increases in the aggregate bank commitments up to an additional $500 million.

Any increases in aggregate bank commitments are subject to identifying lenders, whether existing or new, willing to provide the additional commitments and, in the case of any new lenders, the consent of the Administrative Agent (appointed and authorized by credit facility lenders to exercise powers delegated in the credit agreement) and certain of the lenders under 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 will 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 $100,000,000 in the aggregate by Generation under its credit facility will constitute an event of default under the Exelon credit facility.

At December 31, 2008, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under the credit agreements:

Borrower	Aggregate Bank Commitment [(a)]	Outstanding Borrowings/ Facility Draws	Outstanding Letters of Credit	Available Capacity under Revolving Credit Agreements
Exelon	$ 957	$—	$ 5	$ 952
Generation	4,834	—	127	4,707
ComEd	952	60	141	751
PECO	574	—	93	481

(a) Represents the total bank commitments to the borrower under credits agreements to which the borrower is a party.

Interest rates on advances under the credit facilities are based on either prime or the London Interbank Offered Rate (LIBOR) plus an adder based on the credit rating of the borrower as well as the total outstanding amounts under the agreement at the time of borrowing. In the cases of Exelon, PECO and Generation, the maximum LIBOR adder is 65 basis points; and in the case of ComEd, it is 162.5 basis points.

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, 2008:

	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, 2008, the Registrants were in compliance with the foregoing thresholds.

Long-Term Debt

The following tables present the outstanding long-term debt at Exelon as of December 31, 2008 and 2007:

	Rates	Maturity Date	December 31, 2008	December 31, 2007
Long-term debt				
First Mortgage Bonds [a] [b]:				
Fixed rates	3.50%-8.00%	2008-2038	$ 6,396	$ 5,161
Floating rates	0.80%-4.50%	2013-2020	191	497
Notes payable and other [c]	6.33%-8.00%	2008-2020	4,290	4,323
Pollution control notes:				
Floating rates	1.00%-3.75%	2016-2042	566	566
Sinking fund debentures	3.875%-4.75%	2008-2011	4	6
Total long-term debt			11,447	10,553
Unamortized debt discount and premium, net			(37)	(36)
Unamortized settled fair-value hedge, net			(1)	(1)
Fair-value hedge carrying value adjustment, net			17	4
Long-term debt due within one year			(29)	(605)
Long-term debt			$11,397	$ 9,915
Long-term debt to financing trusts [d]				
Payable to ComEd Transitional Funding Trust	5.74%	2008	$ —	$ 274
Payable to PETT	6.13%-7.65%	2008-2010	1,124	1,732
Subordinated debentures to ComEd Financing II [e]	8.50%	2027	—	155
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			1,514	2,551
Long-term debt due to financing trusts due within one year			(319)	(501)
Long-term debt to financing trusts			$ 1,195	$ 2,050

(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 $40 and $43 million at December 31, 2008 and 2007, respectively. Lease payments of $2 million, $2 million, $3 million, $2 million, $2 million and $29 million will be made in 2009, 2010, 2011, 2012, 2013 and thereafter, respectively.

(d) Amounts owed to these financing trusts are recorded as debt to financing trusts within Exelon's Consolidated Balance Sheets.

(e) ComEd redeemed at a prepayment price of 103.825% the subordinated debentures held by ComEd Financing II and the related trust preferred securities of ComEd Financing II during the first quarter of 2008. A portion of the proceeds from a January 16, 2008 mortgage bond issuance was used to refinance these obligations.

Long-term debt maturities at Exelon in the periods 2009 through 2013 and thereafter are as follows:

Year	
2009	$ 29
2010	615
2011	1,800
2012	827
2013	554
Thereafter	7,622
Total	$11,447

Long-term debt to financing trusts maturities at Exelon, ComEd and PECO in the periods 2009 through 2013 and thereafter are as follows:

Year	
2009	$ 319
2010	805
2011	—
2012	—
2013	—
Thereafter	390
Total	$1,514

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 stock.

11. Income Taxes

Income tax expense (benefit) from continuing operations is comprised of the following components:

For the Year Ended December 31, 2008	
Included in operations:	
Federal	
Current	$ 790
Deferred	341
Investment tax credit amortization	(12)
State	
Current	169
Deferred	29
Total income tax expense	$1,317

For the Year Ended December 31, 2007	
Included in operations:	
Federal	
Current	$1,269
Deferred	34
Investment tax credit amortization	(12)
State	
Current	285
Deferred	(130)
Total income tax expense	$1,446

For the Year Ended December 31, 2006	Exelon
Included in operations:	
Federal	
Current	$ 935
Deferred	112
Investment tax credit amortization	(13)
State	
Current	200
Deferred	(28)
Total income tax expense	$1,206

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, 2008

U.S. Federal statutory rate	35.0%
Increase (decrease) due to:	
State income taxes, net of Federal income tax benefit	3.2
Qualified nuclear decommissioning trust fund losses	(3.2)
Domestic production activities deduction	(1.3)
Tax exempt income	(0.2)
Nontaxable postretirement benefits	(0.3)
Amortization of investment tax credit	(0.2)
Other	(0.4)
Effective income tax rate	32.6%

For the Year Ended December 31, 2007

U.S. Federal statutory rate	35.0%
Increase (decrease) due to:	
State income taxes, net of Federal income tax benefit	2.5
Synthetic fuel-producing facilities credit	(1.9)
Qualified nuclear decommissioning trust fund income	1.0
Domestic production activities deduction	(1.4)
Tax exempt income	(0.3)
Nontaxable postretirement benefits	(0.3)
Amortization of investment tax credit	(0.3)
Research and development credit charge (refund)	0.6
Other	(0.2)
Effective income tax rate	34.7%

For the Year Ended December 31, 2006

U.S. Federal statutory rate	35.0%
Increase (decrease) due to:	
State income taxes, net of Federal income tax benefit	4.0
Nondeductible goodwill impairment charge	9.7
Synthetic fuel-producing facilities credit	(3.6)
Qualified nuclear decommissioning trust fund income	0.5
Domestic production activities deduction	(0.7)
Tax exempt income	(0.4)
Nontaxable postretirement benefits	(0.4)
Amortization of investment tax credit	(0.4)
Investment tax credit charge (refund)	(0.1)
Research and development credit charge (refund) [(a)]	(0.1)
Amortization of regulatory asset	0.2
Plant basis differences	0.3
Other	(0.9)
Effective income tax rate	43.1%

The tax effects of temporary differences, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2008 and 2007 are presented below:

For the Year Ended December 31, 2008

Plant basis differences	$(5,139)
Stranded cost recovery	(896)
Unrealized (gains) losses on derivative financial instruments	(561)
Deferred pension and postretirement obligations	1,542
Emission allowances	(31)
Nuclear decommissioning activities	(87)
Deferred debt refinancing costs	(65)
Goodwill	4
Other, net	453
Deferred income tax liabilities (net)	$(4,780)
Unamortized investment tax credits	(236)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(5,016)

For the Year Ended December 31, 2007

Plant basis differences	$(4,370)
Stranded cost recovery	(1,207)
Unrealized (gains) losses on derivative financial instruments	390
Deferred pension and postretirement obligations	365
Emission allowances	(31)
Nuclear decommissioning activities	(49)
Deferred debt refinancing costs	(66)
Goodwill	4
Other, net	246
Deferred income tax liabilities (net)	$(4,718)
Unamortized investment tax credits	(248)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(4,966)

At December 31, 2008, Exelon had state capital loss carryforwards for income tax purposes of $415 million ($11 million deferred tax asset), which will expire beginning in 2009. At December 31, 2008, PECO had net state capital loss carryforwards of $20 million ($1 million deferred tax asset). At December 31, 2008, Exelon had state net operating loss carryforwards of $749 million ($36 million deferred tax asset), which will expire beginning in 2019.

As of December 31, 2008 and 2007, Exelon had recorded valuation allowances of $18 million and $33 million, respectively, Generation had recorded valuation allowances of approximately $10 million and $32 million, respectively, and PECO had recorded valuation allowances of approximately $1 million and $1 million, respectively, with respect to deferred taxes associated with separate company state taxes.

Tabular reconciliation of unrecognized tax benefits

The following table provides a reconciliation of Exelon's unrecognized tax benefits as of December 31, 2008:

Unrecognized tax benefits at January 1, 2008	$ 1,582
Increases based on tax positions prior to 2008	18
Change to positions that only affect timing	(74)
Increases based on tax positions related to 2008	3
Decreases related to settlements with taxing authorities	(25)
Decrease from expiration of statute of limitations	(9)
Unrecognized tax benefits at December 31, 2008	$ 1,495

Included in Exelon's unrecognized tax benefits balance at December 31, 2008 is approximately $1.4 billion of tax positions for which the ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. The disallowance of such positions would not materially affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

The following table provides a reconciliation of Exelon's unrecognized tax benefits as of December 31, 2007:

Unrecognized tax benefits at January 1, 2007	$ 1,462
Increases based on tax positions prior to 2007	6
Change to positions that only affect timing	127
Increases based on tax positions related to 2007	3
Decreases related to settlements with taxing authorities	(16)
Unrecognized tax benefits at December 31, 2007	$ 1,582

Included in Exelon's unrecognized tax benefits balance at December 31, 2007 is approximately $1.5 billion of tax positions for which the ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. The disallowance of such positions would not materially affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

Unrecognized tax benefits that if recognized would affect the effective tax rate

Exelon, Generation and ComEd have $93 million, $28 million and $65 million, respectively, of unrecognized tax benefits at December 31, 2008 that, if recognized, would decrease the effective tax rate. Exelon, Generation and ComEd had $67 million, $22 million and $25 million, respectively, of unrecognized tax benefits at December 31, 2007 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, 2008 a net interest receivable (payable) of $(16) million, $(10) million, $(90) million and $48 million, respectively, related to their unrecognized tax benefits. Exelon, Generation, ComEd and PECO reflected in their Consolidated Balance Sheets as of December 31, 2007 a net interest receivable (payable) of $(44) million, $(22) million, $(88) million and $42 million, respectively, related to their unrecognized tax benefits. The Registrants recognize accrued interest related to unrecognized tax benefits in interest expense (income) in other income and deductions on their Consolidated Statements of Operations. Exelon, Generation, ComEd and PECO have reflected in their Consolidated Statements of Operations net interest expense (income) of $(31) million, $(11) million, $(2) million and $(12) million, respectively, related to their uncertain tax positions for the twelve months ended December 31, 2008. For the twelve months ended December 31, 2007, Exelon, Generation, ComEd and PECO reflected in their Consolidated Statements of Operations net interest expense (income) of $(49) million, $24 million, $(41) million and $(20) million, respectively, related to their uncertain tax positions. The Registrants have not accrued any penalties with respect to unrecognized tax benefits.

Reasonably possible that total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Exelon has unrecognized tax benefits related to refund claims for Illinois investment tax credits with respect to its utility property of approximately $87 million, of which $22 million and $65 million relate to Generation and ComEd, respectively. After the refund claims were denied by the Illinois Department of Revenue, Exelon filed a suit for a refund. In the third quarter of 2007, the Illinois Appellate court heard the case deciding in favor of the Illinois Department of Revenue. In September 2008, the Illinois Supreme court heard oral arguments in the case. A decision is expected in 2009. It is reasonably possible that the unrecognized tax benefits related to this issue will significantly decrease within the next 12 months as a result of a decision by the Illinois Supreme Court or a settlement with the Department of Revenue.

Generation 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. That additional basis results primarily in increased tax depreciation and amortization deductions. The Internal Revenue Service (IRS) disagrees with this

position and has disallowed the claims. During 2008, Generation had several discussions with the appeals division of the IRS (IRS Appeals) but was unable to reach a satisfactory settlement. In November 2008, Generation received a final partnership determination disallowing the refund claims. Generation expects to file a petition in the Tax Court, the District Court, or the Court of Federal Claims in the first quarter of 2009 to contest this determination. Due to the expected length of the litigation, Generation does not believe that it is reasonably possible that the total amount of unrecognized tax benefits will significantly decrease in the next 12 months.

Exelon contends that the Illinois and Pennsylvania deregulation acts 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 competitive transition charges (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. If the Company is successful in its claims, it will be required to reduce the tax basis of property acquired with the funds provided by the CTCs such that the benefits of the position are temporary in nature. The IRS has disallowed the refund claims for the 1999—2001 tax years and Exelon has protested the disallowance to IRS Appeals. The years 2002—2006 are currently under IRS audit and the Company expects the claims for those years to be disallowed. ComEd collected approximately $1.2 billion in CTCs for the years 1999—2006. PECO has collected approximately $3.6 billion in CTCs for the years 2000-2008 and will continue the collection of CTCs through 2010. ComEd and PECO have recognized tax benefits associated with the CTC refund claims and have accrued interest on this tax position consistent with the requirements of FIN 48. Exelon's, ComEd's, and PECO's management believe that the issue has been appropriately recognized in accordance with FIN 48; however, the ultimate outcome of this matter could result in unfavorable or favorable impacts to the results of operations and financial positions as well as potential favorable impacts to cash flows, and such impacts could be material. Based on the schedule for the IRS appeal, it is reasonably possible that the unrecognized tax benefits related to this issue may significantly increase or decrease within the next 12 months. It is not possible at this time to predict the amount, if any, of such a change.

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.

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	1989-2007
Exelon (and predecessors) and subsidiaries Illinois unitary income tax returns	2004-2007
Exelon Ventures Company, LLC Pennsylvania corporate net income tax returns	2004-2007
PECO Pennsylvania corporate net income tax returns	2003-2007

Other Tax Matters

1999 Sale of Fossil Generating Assets

Exelon, through its ComEd subsidiary, has taken certain tax positions to defer the tax gain on the 1999 sale of its fossil generating assets. As of December 31, 2008 and December 31, 2007, deferred tax liabilities related to the fossil plant sale are reflected in Exelon's Consolidated Balance Sheets with the majority allocated to ComEd and the remainder to Generation. Exelon's ability to defer the tax liability depends in part on whether its treatment of the sales proceeds as having been received in connection with an involuntary conversion is ultimately sustained. Exelon's ability to continue to defer the remainder of the tax liability on the fossil plant sale depends on whether its tax characterization of a purchase and leaseback transaction is sustained as an acquisition of replacement property as part of a "like-kind exchange." Exelon received the IRS' audit report for the taxable period 1999 through 2001, which, as expected, 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 has asserted that the sales proceeds were not received in connection with an involuntary conversion of certain ComEd property rights such 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 sale-in, lease-out (SILO), which the IRS does not respect as the acquisition of an ownership interest in property. Accordingly, the IRS asserted that the sale of the fossil plants followed by the purchase and leaseback does not qualify as a like-kind exchange such that the gain on the sale is fully subject to tax. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. As a result of its view of the purchase and leaseback as a tax shelter and because it disagrees with Exelon's position that the sale of the fossil plants resulted from an involuntary conversion, the IRS has asserted penalties for a substantial understatement of tax of approximately $196 million.

As part of a coordinated settlement initiative for SILO and LILO (lease-in, lease-out) transactions, Exelon and 44 other large corporate taxpayers received a settlement offer from the IRS in August 2008. The terms of the offer required a concession of 80% of the deferral on Exelon's like-kind exchange position. Exelon believes that the settlement offer does not adequately reflect the strength of its position and has rejected the offer. As discussed below, Exelon intends to continue discussing the fossil sale tax positions with IRS Appeals.

Exelon disagrees with the IRS's disallowance of the deferral of gain and specifically with its characterization of its purchase and leaseback as a SILO. Following the conclusion of the IRS audit, Exelon initiated an administrative appeal with the IRS in an effort to negotiate a settlement of the disputed issues without having to resort to litigation. Exelon and the IRS have agreed to a schedule which could result in a resolution of the administrative appeal within the next 12 months. That resolution could take the form of a negotiated settlement of the disputed issues. Alternatively, either or both parties could conclude that a settlement cannot be reached, in which case the issues would likely be resolved through litigation. In the event Exelon reaches a settlement with the IRS or determines it is necessary to litigate the unsettled issues by filing a suit for refund, it is not expected that any payments of tax or interest would be required before the first quarter of 2010.

Exelon and ComEd have recorded a liability for unrecognized tax benefits. Additionally, Exelon and ComEd have accrued interest on these tax positions consistent with the requirements of FIN 48. A fully successful IRS challenge to Exelon's and ComEd's positions would accelerate income tax payments and increase interest expense related to the deferred tax gain that becomes currently payable. As of December 31, 2008, Exelon's and ComEd's potential net cash outflow, including tax and interest (after tax), could be as much as $1 billion. If the deferral were successfully challenged by the IRS, it could negatively impact Exelon's and ComEd's results of operations by as much as $199 million (after tax) related to interest expense. Because Exelon believes it is unlikely that the penalty assertion will be ultimately sustained, Exelon and ComEd have not recorded a liability for the penalties. However, should the IRS prevail in asserting such penalty, it would result in an after-tax charge of an additional $196 million to Exelon's and ComEd's results of operations. Exelon's and ComEd's management believe that interest and penalties have been appropriately accounted for in accordance with FIN 48; however, the ultimate outcome of such matters could result in unfavorable or favorable impacts to the results of operations, cash flows and financial positions, and such impacts could be material. Based on the schedule for the IRS appeal, it is reasonably possible that unrecognized tax benefits associated with the involuntary conversion position and like-kind exchange transaction could change significantly within the next 12 months. It is not possible at this time to predict the amount, if any, of such a change.

Indirect Cost Capitalization

In 2001, Exelon filed a request with the IRS to change its tax method of accounting for certain overhead costs under the Simplified Service Cost Method (SSCM) effective for years 2001-2004. The tax method change resulted in the deduction of certain overhead costs previously capitalized. In the fourth quarter of 2007, Exelon and the IRS agreed to apply industry-wide guidelines for settling the amount of indirect overhead costs previously capitalized. Based on acceptance of the settlement guidelines, Exelon recorded, in the fourth quarter of 2007, an estimated interest benefit of approximately $40 million (after-tax) net of a contingent tax consulting fee of $6 million (after-tax). ComEd and PECO recorded an estimated interest benefit (after-tax and net of fee) of approximately $26 million and $8 million, respectively. ComEd and PECO recorded a current tax benefit of $13 million and $26 million, respectively, offset with a deferred tax expense recorded at Generation of $38 million. In the second quarter of 2008, Exelon reached final settlement with the IRS as to the amounts of the benefit determined through the application of the IRS settlement guidelines. As a result, Exelon recognized an additional interest benefit of $10 million (after-tax) of which $7 million and $2 million of the interest benefit was attributable to ComEd and PECO, respectively. ComEd and PECO recorded a current tax benefit of $4 million and $2 million, respectively, offset with a deferred tax expense recorded at Generation of $6 million.

For years beginning after 2004, Exelon, ComEd and PECO were required to discontinue use of the SSCM and adopt a new method of capitalizing indirect costs. In the third quarter of 2007 ComEd and PECO developed a new indirect cost capitalization method. As a result, Exelon recorded an estimated interest benefit of $5 million (after-tax). ComEd and PECO recorded an estimated interest benefit (after-tax) of $2 million and $3 million, respectively. During the fourth quarter of 2008, the IRS indicated its agreement with this new method of capitalizing indirect overhead costs. Therefore, Exelon recorded an additional interest benefit (after-tax) of $12 million of which $15 million and $2 million was attributable to ComEd and PECO, respectively.

Research and Development Settlement

In 2007, ComEd and the IRS reached an agreement to settle a research and development claim for tax years 1989-1998. The incremental impact recorded by ComEd in the fourth quarter of 2007, above the amount recorded with the adoption of FIN 48,

resulted in a reduction to goodwill of $35 million, interest income of $15 million (after tax) and a contingent tax consulting fee of $8 million (after tax). Generation recorded a deferred tax liability and tax expense of $27 million related to the reduction of future depreciation due to the basis reduction of the related assets transferred from ComEd. The contingent fee was accounted for under SFAS No. 5 and recognized in the fourth quarter of 2007.

Tax Sharing Agreement

Generation, ComEd and PECO are all party to an agreement (Tax Sharing Agreement) with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits. 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 the parent is reallocated to the other members. That allocation is treated as a contribution to the capital of the party receiving the benefit.

Tax Restructuring

In the fourth quarter of 2007, Exelon completed a tax restructuring to allow the utilization of separate company losses for state income tax purposes. As a result of the restructuring, Exelon recorded a deferred tax benefit of approximately $63 million related primarily to temporary differences originating through OCI. The effect of the tax restructuring in the fourth quarter of 2007 and its impact on the deferred tax assets at Exelon were recorded in net income in accordance with SFAS No. 109.

Interest on Tax Refunds

During the first quarter of 2008 and after the filing of the Registrants' 2007 Annual Report on Form 10-K, Generation and ComEd identified adjustments to be made for amounts recorded in 2007 related to a settlement with the IRS of a research and development claim. Upon further review of the settlement and Exelon's Tax Sharing Agreements, it was determined that $4 million (after tax) of interest expense recorded in the fourth quarter of 2007 upon finalization of the settlement with the IRS and $2 million of interest recorded through retained earnings in the first quarter of 2007 upon the adoption of FIN 48 was inadvertently recorded at Generation and should have been recorded at ComEd. Management believed these amounts are immaterial individually and in the aggregate to any previously issued financial statements, and also immaterial to expected full year results of operations for 2008. Consequently during the first quarter of 2008, ComEd recorded an increase in interest expense of $4 million (after tax) and a reduction in retained earnings of $2 million and Generation recorded a reduction in interest expense of $4 million (after tax) and an increase in retained earnings of $2 million. There was no net impact at Exelon for the adjustment related to the settlement with the IRS as the adjustments to ComEd and Generation were offset in consolidation.

Illinois Senate Bill 1544 and Senate Bill 783

In August 2007, the Governor of Illinois signed Illinois Senate Bill (SB) 1544 into law, which became effective January 1, 2008. SB 1544 provided for new rules related to the sourcing of receipts from services for Illinois income tax purposes. These rules generally sourced receipts from services based upon where the benefit of the service was realized. In January 2008, the Governor of Illinois signed Illinois SB 783 into law, which amended certain provisions of SB 1544, including the rules pursuant to which receipts from services should be sourced for Illinois income tax purposes. Pursuant to SB 783, receipts from services generally should be sourced based upon where the services are received. SB 783 also expressly provides that the Illinois Department of Revenue shall adopt rules prescribing where utility services are received. On December 26, 2008, the Illinois Department of Revenue proposed regulations prescribing where utility services are received. These proposed regulations are susceptible to change until they are finalized, which is not expected to occur until March 2009 at the earliest. Exelon will assess the impact that SB 783 may have on its financial position, results of operations and cash flows once the Illinois Department of Revenue finalizes regulations prescribing where utility services are received, which as stated above, is not expected to occur until March of 2009. The impact may be material.

Investments in Synthetic Fuel-Producing Facilities

Exelon, through three separate wholly owned subsidiaries, owned interests in two limited liability companies and one limited partnership (collectively, the sellers) that own synthetic fuel-producing facilities. Prior to December 31, 2007, Section 45K (formerly Section 29) of the Internal Revenue Code provided tax credits for the sale of synthetic fuel produced from coal. The ability to earn these synthetic fuel tax credits expired on December 31, 2007 and, as such, the synthetic fuel-producing facilities that Exelon had interests in ceased operations on or before December 31, 2007. The agreements with the Sellers terminated in 2008.

Section 45K contained a provision under which the tax credits were phased out (i.e., eliminated) in the event crude oil prices for a year exceeded certain thresholds. Exelon was required to pay for tax credits based on the production of the facilities regardless of whether or not a phase-out of the tax credits was anticipated. However, Exelon had the legal right to recover a portion of the payments made to the Sellers related to phased-out tax credits. In March 2008, the IRS published the 2007 oil Reference Price, which resulted in a 67% phase-out of tax credits for calendar year 2007 that reduced Exelon's earned after-tax credits of $258 million to $85 million for the year ended December 31, 2007. At December 31, 2007, Exelon had estimated the 2007 phase-out to be 68% and had net receivables on its Consolidated Balance Sheet from the Sellers totaling $171 million associated with the portion of the payments previously made to the Sellers related to tax credits that were phased out for 2007. The difference between the actual 2007 phase-out and the 2007 phase-out previously estimated resulted in a $4 million increase in 2007 tax credits and a corresponding after-tax expense of $4 million, which has been reflected in Exelon's operating results for the year ended December 31, 2008.

Interests in synthetic fuel-producing facilities did not have any net impact on Exelon's net income for the year ended December 31, 2008, and increased (reduced) Exelon's net income by $87 million and $(24) million during the years ended December 31, 2007 and 2006, respectively. Net income from interests in synthetic fuel-producing facilities is reflected in the Consolidated Statements of Operations within income taxes, operating and maintenance expense, depreciation and amortization expense, interest expense, equity in losses of unconsolidated affiliates and other, net.

The principal balance of the non-recourse notes payable, which was included in Exelon's purchase price for these facilities, was $21 million at December 31, 2007. The final note payment was made in January 2008 to reduce the non-recourse notes payable principal balance to zero.

12. Asset Retirement Obligations

Nuclear AROs

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. Generation will pay for its obligations using trust funds that have been established for this purpose. The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's Consolidated Balance Sheets, from January 1, 2007 to December 31, 2008:

Asset retirement obligation at January 1, 2007	$3,533
Net decrease resulting from updates to estimated future cash flows	(171)
Accretion expense	227
Payments to decommission retired plants	(11)
Asset retirement obligation at December 31, 2007	$3,578
Net decrease resulting from updates to estimated future cash flows	(300)
Accretion expense	221
Payments to decommission retired plants	(14)
Asset retirement obligation at December 31, 2008 [(a)]	$3,485

(a) Includes $13 million and $16 million as the current portion of the ARO at December 31, 2008 and 2007, respectively, which is included in other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

During 2008, Generation recorded a net decrease in the ARO of $300 million, primarily due to an update in the third quarter of 2008, which reflected updated decommissioning cost studies received for seven nuclear units, a decline from the previous year in the cost escalation factor assumptions used to estimate future undiscounted decommissioning costs, and a change in management's expectation of the year in which the Department of Energy will begin accepting spent nuclear fuel (from the previous estimate of 2018 to 2020), partially offset by a change in the probabilities assigned to decommissioning alternatives for Zion Station to reflect a revised probability for accelerated decommissioning. This decrease in the ARO also resulted in the recognition of $19 million of income (pre-tax), which is included in operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations, representing the reduction in the ARO in excess of the existing asset retirement cost balances for the Unregulated Units.

During the third quarter of 2007, Generation recorded a net decrease in the ARO of $171 million, primarily due to a decline from the previous year in the cost escalation factor assumptions used to estimate future undiscounted decommissioning costs and updated

decommissioning cost studies received for six nuclear units. This decrease in the ARO also resulted in the recognition of $29 million of income (pre-tax), which is included in operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations, representing the reduction in the ARO in excess of the existing asset retirement cost balances for the Unregulated Units.

Overview of Trust Funds. Trust funds have been established on a unit-by-unit basis to satisfy Generation's nuclear decommissioning obligations. Trust funds established for any particular unit may not be used to fund the decommissioning obligations of any other unit.

The trusts 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. After 2006, ComEd no longer collects amounts to pay for decommissioning costs based on an ICC order. PECO currently recovers 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 recovered from PECO customers are remitted to Generation and deposited into the trust funds. Every five years, the PAPUC reviews the adequacy of the annual amount that PECO is allowed to collect from its customers. Based on this review, the PAPUC may adjust PECO's collections upward or downward. Based on the most recent PAPUC review, effective January 1, 2008, the annual collection amount was set at $29 million, down from the previous annual level of $33 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 trust funds from amounts collected from ComEd and PECO customers, Generation has not made contributions to the trust funds.

Any shortfall of funds necessary for decommissioning, determined on a plant-by-plant basis, is ultimately required to be funded by Generation. Generation has recourse to collect additional amounts from PECO customers, 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 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 plants. With respect to the former ComEd and PECO units, any funds remaining in the trusts 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 trusts after 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. During 2008, the value of the trust funds declined significantly due to unrealized losses as a result of adverse financial market conditions. Despite this decline in value, Generation believes that the decommissioning trust funds for the nuclear generating stations formerly owned by ComEd, PECO and AmerGen, the expected earnings thereon and, in the case of the former PECO stations, the amounts collected from PECO's customers will ultimately be sufficient to fully fund Generation's decommissioning obligations for its nuclear generating stations in accordance with NRC regulations. However, NRC minimum funding requirements may require Generation to take steps to address the funded status of the trust funds. Generation is required to provide to the NRC a biennial report by unit (annually for Generation's five units that have been retired or are within five years of the current approved license life) addressing Generation's ability to meet the NRC-estimated 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. Generation's next report to the NRC is due on March 31, 2009, based on trust fund values and estimated decommissioning obligations as of December 31, 2008. Based on these values, six units at three nuclear generating stations were in an underfunded position by approximately $185 million in total at December 31, 2008, relative to the NRC minimum funding requirements. Exelon and Generation currently are evaluating the remedy that will be used to address the underfunded status.

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 trust funds necessary for decommissioning the former ComEd units on a unit-by-unit basis, as long as funds held in the nuclear decommissioning trust funds exceed the total estimated decommissioning obligation, decommissioning impacts recognized in the Consolidated Statement of Operations, including realized and unrealized income and losses on the trust funds and accretion of the decommissioning obligation, are generally offset within

Exelon's and Generation's Consolidated Statements of Operations. Should the value of the trust fund for any former ComEd unit fall below the amount of the estimated decommissioning obligation for that unit, the accounting to offset decommissioning impacts in the Consolidated Statement of Operations for that unit would be discontinued, the decommissioning impacts would be recognized in the Consolidated Statements of Operations and the adverse impact to Exelon's and Generation's results of operations and financial position could be material. At December 31, 2008, the trust funds of each of the former ComEd units exceeded the related decommissioning obligation for each of the units. Based on the regulatory agreement with the PAPUC that dictates Generation's rights and obligations related to the shortfall or excess of trust funds necessary for decommissioning the former PECO units on a unit-by-unit basis, regardless of whether the funds held in the nuclear decommissioning trust funds exceed or fall short of the total estimated decommissioning obligation, decommissioning impacts recognized in the Consolidated Statement of Operations are generally offset within Exelon's and Generation's Consolidated Statements of Operations. The offset of decommissioning impacts within the Consolidated Statement of Operations results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd and PECO have recorded equal noncurrent affiliate receivables from Generation and corresponding regulatory liabilities. The decommissioning impacts of the Unregulated Units are reflected in Exelon's and Generation's Consolidated Statements of Operations, 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 to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Fair Value Option for Financial Assets and Liabilities. Effective January 1, 2008, Exelon and Generation adopted SFAS No. 159 for all securities held in the nuclear decommissioning trust funds. Prior to the adoption of SFAS No. 159, nuclear decommissioning trust fund investments were classified as available-for-sale securities. Further, as a result of FSP FAS 115-1, Exelon and Generation considered all nuclear decommissioning trust fund investments in an unrealized loss position to be other-than-temporarily impaired. As a result, changes in the fair value of investments in an unrealized loss position were recognized in results of operations whereas changes in the fair value of investments in an unrealized gain position were previously recognized in accumulated OCI. In order to align the accounting treatment of investments in unrealized gain positions with unrealized loss positions, Exelon and Generation have elected the fair value option under SFAS No. 159. With the adoption of SFAS No. 159, Exelon and Generation now classify all securities held in the nuclear decommissioning trust funds as trading securities under FAS 115 and recognize all unrealized and realized gains and losses in results of operations.

As a result of the adoption of SFAS No. 159, Exelon and Generation recorded a cumulative effect adjustment as an increase to the opening balance of retained earnings and undistributed earnings, respectively, as reflected in the table below. The following table presents the unrealized gains related to the nuclear decommissioning trust fund investments that were included in accumulated OCI on Exelon's and Generation's Consolidated Balance Sheets as of December 31, 2007, prior to the adoption of SFAS No. 159.

December 31, 2007	Accumulated OCI				
	Gross Unrealized Gains	Contractual Elimination [a]	Subtotal	Deferred Income Taxes	Net Unrealized Gains
Regulated Units	$1,081	$871	$210	$181	$ 29
Unregulated Units	236	—	236	105	131
Total	$1,317	$871	$446	$286	$160

(a) Represents the elimination of the gross unrealized gains and certain income taxes related to the nuclear decommissioning trust fund investments associated with the Regulated Units, which are included in regulatory liabilities on Exelon's Consolidated Balance Sheets and in noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.

Trust Fund Investments. The following table shows the fair values of the securities held in the nuclear decommissioning trust funds as of December 31, 2008 and 2007:

	December 31,	
	2008	2007
Cash and cash equivalents	$ 78	$ 195
U.S. Treasury obligations and direct obligations of U.S. government agencies	924	1,387
Federal agency mortgage-backed securities	1,501	1,251
Commercial mortgage-backed securities	111	96
Corporate bonds	793	417
Other debt securities	107	82
Marketable equity securities	2,123	3,466
Other [(a)]	(137)	(71)
Total	$5,500	$6,823

(a) Represents payables related to pending securities purchases net of receivables related to pending securities sales and interest receivables. Includes collateral of $386 million and $660 million at December 31, 2008 and 2007, respectively offset by corresponding payables of $386 million and $660 million related to securities lending transactions. See below for additional details.

Generation's decommissioning trust funds participate in a securities lending program with the trustees of the funds. The program authorizes the trustees to loan securities that are assets of the trust funds to approved borrowers. The trustees require borrowers, pursuant to a security lending agreement, to deliver collateral to secure each loan. The securities 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, which are adjusted daily, must be maintained at a level no less than 100% of the market value of borrowed securities. Cash collateral received is primarily invested in a short-term collateral fund, but may also be invested in assets with maturities matching, or approximating, the duration of the loan of the related securities. Collateral may not be sold or re-pledged by the trustees, however, the borrowers may sell or re-pledge the securities loaned. Generation bears the risk of loss with respect to its invested cash collateral. Such losses may result from a decline in fair value of specific investments or due to liquidity impairments resulting from current market conditions. Losses recognized by Generation have not been significant to date. Management continues to monitor the performance of the invested collateral and to work closely with the trustees to limit any potential further losses. During the fourth quarter of 2008, Generation was able to withdraw over 35% of its collateral balance, as of September 30th, 2008, without realizing any losses on its investment.

Generation, the trustees and the borrowers have the right to terminate the lending agreement at any time. In the event of termination, the borrowers must return the loaned securities or surrender the collateral. In the fourth quarter of 2008, Generation decided to end its participation in the securities lending program. However, Generation has chosen to initiate a gradual withdrawal of the trusts' investments in order to minimize potential losses due to the lack of liquidity in the market. Currently, the weighted average maturity of the securities within the collateral pools is approximately 8 months. Generation's withdrawal from the securities lending program based on maturities of securities within the collateral funds is expected to result in the return of approximately 70% of its loaned securities (in terms of value) by the end of 2009 and the return of the remaining securities by the end of 2010.

At December 31, 2008, Generation had $380 million of loaned securities outstanding and held $386 million of related collateral under its lending agreements. At December 31, 2007, Generation had $647 million of loaned securities outstanding and held $660 million of related collateral under its lending agreements. The collateral received pursuant to securities lending transactions is reflected in the table above under "Other" as both an asset and an offsetting liability. A portion of the income generated through the investment of cash collateral is remitted to the borrowers, and the remainder is allocated between the trust funds and the trustees in their capacity as security agents. Securities lending income allocated to the trust funds is included in trust fund earnings and classified as Other, Net in Exelon's and Generation's Consolidated Statements of Operations and was not significant during the years ended December 31, 2008 and December 31, 2007.

The following table provides unrealized gains (losses) on decommissioning trust funds and other-than-temporary impairment of decommissioning trust funds for the years ended 2008, 2007 and 2006:

	For the Years Ended December 31,		
	2008	2007	2006
Net unrealized gains (losses) on decommissioning trust funds—Regulated Units	$(1,023) [b]	$ 43 [b]	$453 [b]
Net unrealized gains (losses) on decommissioning trust funds—Unregulated Units	(324) [c]	(14) [d]	147 [d]
Other-than-temporary impairment of decommissioning trust funds—Regulated Units [a]	n/a	(84) [b]	(29) [b]
Other-than-temporary impairment of decommissioning trust funds—Unregulated Units [a]	n/a	(9) [c]	(3) [c]

(a) As a result of certain NRC restrictions, Exelon and Generation were unable to demonstrate the ability and intent to hold the nuclear decommissioning trust fund investments through a recovery period and, accordingly, recognized any unrealized holding losses immediately.
(b) Subject to contractual elimination pursuant to regulatory accounting and included in regulatory liabilities on Exelon's Consolidated Balance Sheets and noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(c) Included in other, net in Exelon's and Generation's Consolidated Statements of Operations.
(d) Included in accumulated OCI on Exelon's and Generation's Consolidated Balance Sheets.

Interest and dividends on nuclear decommissioning trust fund investments are recognized when earned and are included in other, net in Exelon's and Generation's Consolidated Statements of Operations.

Non-Nuclear AROs

Generation has conditional AROs for plant closure costs associated with its fossil and hydroelectric generating stations, including asbestos abatement, removal of certain storage tanks and other decommissioning-related activities. ComEd and PECO have conditional AROs associated with the abatement and disposal of equipment and buildings contaminated with asbestos and Polychlorinated Biphenyls (PCBs).

The following table presents the activity of the non-nuclear conditional AROs reflected on Exelon's Consolidated Balance Sheets from January 1, 2007 to December 31, 2008:

Non-nuclear AROs at January 1, 2007	$247
Net decrease resulting from updates to estimated future cash flows	(6)
Accretion [a]	15
Payments	(6)
Non-nuclear AROs at December 31, 2007	250
Net increase resulting from updates to estimated future cash flows	8
Accretion [a]	14
Payments	(10)
Non-nuclear AROs at December 31, 2008	$262

(a) For ComEd and PECO, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulations.

13. Spent Nuclear Fuel Obligation

Under the Nuclear Waste Policy Act of 1982 (NWPA), the DOE is responsible for the development of a 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 its nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation pays the DOE one mill ($.001) per kilowatt-hour (kWh) of net nuclear generation for the cost of nuclear fuel long-term 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. DOE's press statement accompanying the release of the plan indicated that shipments to the repository are not expected to begin before 2020. Given the program's history of

funding restrictions, it is possible that shipments to the repository may not begin by 2020. 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 its best estimate of when DOE will begin accepting SNF. This 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 and Quad Cities Stations and its consideration and development of dry cask storage at other stations. In August 2004, Generation and the U.S. Department of Justice, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse Generation for costs associated with storage of spent fuel 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 spent nuclear fuel. 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 June 30, 2008, totaling approximately $297 million ($223 million after considering amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek). As of December 31, 2008, the amount of spent fuel storage costs for which reimbursement will be requested from the DOE under the settlement agreement is $36 million, which is recorded within accounts receivable, other. This amount is comprised of $11 million, which has been recorded as a reduction to operating and maintenance expense, and $23 million, which has been recorded as a reduction to capital expenditures. The remaining $2 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, 2008, the unfunded SNF liability for the one-time fee with interest was $1,015 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, 2008, was 0.538%. The liabilities for spent nuclear fuel disposal costs, including the one-time fee, were transferred to Generation as part of the 2001 corporate restructuring. The outstanding one-time fee obligation for the Oyster Creek and TMI units remains with the former owners. Clinton has no outstanding obligation.

14. Retirement Benefits

Defined Benefit Pension and Other Postretirement Benefits—Consolidated Plans

As of December 31, 2008, Exelon sponsored six defined benefit pension plans and two postretirement benefit plans for essentially all Generation, ComEd, PECO and BSC employees, except for those employees of Generation's former wholly-owned subsidiary, AmerGen, who participate in a separate AmerGen-sponsored defined benefit pension plan and postretirement benefit plan. Effective January 8, 2009, the AmerGen legal entity was dissolved. At that time, Exelon became the sponsor of all AmerGen pension and postretirement benefit plans. The change in sponsorship will not materially impact the funding or substantive provisions of the AmerGen plans.

Exelon's traditional and cash balance pension plans and former AmerGen pension plan are intended to be tax-qualified defined benefit plans. Substantially all Exelon non-union employees and electing union employees hired on or after January 1, 2001 participate in Exelon-sponsored cash balance pension plans. Effective January 1, 2009, substantially all newly hired union-represented employees will participate in cash balance pension plans. Exelon submitted applications to the IRS for rulings on the tax-qualification of the form of its plans for non-union and electing union employees. On June 1, 2004, the IRS issued a favorable ruling on the union cash balance plan. Exelon received a favorable ruling with respect to its non-union cash balance plan on February 8, 2008, and AmerGen has not yet submitted an application with respect to the AmerGen cash balance formula, due to the recently-lifted IRS moratorium on issuing any rulings to plans that were involved in a so-called "conversion" from a traditional to a cash balance formula.

The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, including numerous assumptions and accounting elections. When determining the various assumptions that are required, Exelon considers historical information as well as future expectations. The benefit costs are affected by, among other things, the actual rate of return on plan assets, the long-term expected rate of return on plan assets, the discount rate applied to benefit obligations, Exelon's expected level of contributions to the plans, incidence of mortality, expected remaining service period of plan participants, level of compensation and rate of compensation increases, employee age, length of service, the long-term expected investment crediting rate and the anticipated rate of increase of health care costs. The impact of changes in these factors on pension and other postretirement benefit obligations is generally recognized over the expected average remaining service period of the plan participants rather than immediately recognized. The measurement date for the plans is December 31.

In accordance with SFAS No. 158, which became effective December 31, 2006, Exelon and Generation are required to recognize the overfunded or underfunded status of defined benefit pension and other postretirement plans as an asset or liability on their balance sheets.

The Pension Protection Act of 2006 (the Act), became effective January 1, 2008 and requires companies to, among other things, maintain certain defined minimum funding thresholds (or face plan benefit restrictions), pay higher premiums to the Pension Benefit Guaranty Corporation if they sponsor defined benefit plans, amend plan documents and provide additional plan disclosures in regulatory filings and to plan participants. Generally, effective January 1, 2008 (January 1, 2009 for most union-represented employees), Exelon prospectively amended the vesting schedule, benefit crediting rate and investment crediting rate of its relevant cash balance pension plans in accordance with interim guidance issued by the U.S. Treasury Department pursuant to the Act. These changes to the cash balance pension plans did not have a significant impact on Exelon's or Generation's results of operations or cash flows. The U.S. Treasury Department's interim guidance indicates that additional guidance will be forthcoming, and it is possible that Exelon will make additional amendments to its cash balance plans in response to that guidance.

The Worker, Retiree, and Employer Recovery Act of 2008 (WRERA) was signed into law on December 23, 2008. WRERA grants plan sponsors relief from certain funding requirements and benefit restrictions, and also provides some technical corrections to the Act. There are two primary provisions that impact funding results for Exelon. First, required contributions will be based on a percentage of the funding target for years beginning before 2011, rather than a funding target of 100%. These percentages are 92%, 94% and 96% in 2008, 2009 and 2010, respectively. Second, one of the technical corrections, referred to as asset smoothing, allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of funding requirements. Exelon has not yet determined whether it will elect this option. If Exelon were to elect the asset smoothing option, it would provide Exelon the opportunity to defer certain contributions to later years or potentially mitigate future contributions through market recovery.

For the year ended December 31, 2008, Exelon and AmerGen's pension and postretirement benefit plans experienced actual negative asset returns of approximately 26%. These negative returns during 2008 were a primary driver in causing significant actuarial losses for the year ended December 31, 2008. As of December 31, 2008, reductions in plan assets resulted in an increase of approximately $3.9 billion to the plans' unfunded status.

Obligations and Assets

The following tables provide 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	
	2008	2007	2008	2007
Change in benefit obligation:				
Net benefit obligation at beginning of year	$10,427	$10,396	$3,335	$3,330
Service cost	163	163	108	106
Interest cost	635	603	208	192
Plan participants' contributions	—	—	22	23
Actuarial loss (gain)	176	(143)	(14)	(142)
Plan Amendments	16	—		
Curtailments/settlements	1	7	—	—
Special termination benefits	—	1	—	—
Gross benefits paid	(630)	(600)	(189)	(180)
Federal subsidy on benefits paid	—	—	10	6
Net benefit obligation at end of year	$10,788	$10,427	$3,480	$3,335
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 9,634	$ 9,645	$1,616	$1,512
Actual return on plan assets	(2,420)	553	(388)	82
Employer contributions	80	36	163	179
Plan participants' contributions	—	—	22	23
Gross benefits paid	(630)	(600)	(189)	(180)
Fair value of plan assets at end of year	$ 6,664	$ 9,634	$1,224	$1,616

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,	
	2008	2007	2008	2007
Other current liabilities	$ 13	$ 16	$ 1	$ 2
Pension obligations	4,111	777	—	—
Non-pension postretirement benefit obligations	—	—	2,255	1,717
Unfunded status (net benefit obligation less plan assets)	$4,124	$793	$2,256	$1,719

Funding is based upon actuarially determined contributions that take into account the minimum contribution required under ERISA, as amended, for the pension plans and the amount deductible for income tax purposes for the other postretirement benefit plans. Management considers these and other factors when making funding decisions. The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plan. During 2008, Exelon's unfunded status increased significantly, primarily due to lower than expected 2008 asset returns. The funded status may change over time due to several factors, including contribution levels, assumed discount rates and actual long-term rates of return on plan assets.

The accumulated benefit obligation (ABO) for all defined benefit pension plans was $10,017 million and $9,600 million at December 31, 2008 and 2007, respectively. On an ABO basis, the plans were funded at 67% at December 31, 2008 compared to 100% at December 31, 2007. The projected benefit obligation (PBO) for all defined benefit pension plans was $10,788 million and $10,427 million at December 31, 2008 and 2007, respectively. On a PBO basis, the plans were funded at 62% at December 31, 2008 compared to 92% at December 31, 2007. The ABO differs from the PBO in that it includes no assumption about future compensation levels.

The following table provides the PBO, ABO and fair value of plan assets for all pension plans with an ABO in excess of plan assets.

	December 31,	
	2008	2007
Projected benefit obligation	$10,788	$1,343
Accumulated benefit obligation	10,017	1,293
Fair value of plan assets	6,664	1,061

The following table provides the PBO, ABO and fair value of all pension plans with a PBO in excess of plan assets.

	December 31,	
	2008	2007
Projected benefit obligation	$10,788	$10,427
Accumulated benefit obligation	10,017	9,600
Fair value of plan assets	6,664	9,634

Net Periodic Benefit Cost, OCI and Regulatory Assets

The following table provides the components of the net periodic benefit costs, OCI and regulatory assets for the years ended December 31, 2008, 2007 and 2006 for all plans combined. The table reflects a reduction in 2008, 2007 and 2006 net periodic postretirement benefit cost of approximately $38 million, $44 million and $40 million, respectively, related to a Federal subsidy provided under the Prescription Drug Act. This subsidy has been accounted for under FSP FAS 106-2, as described in Note 1—Significant Accounting Policies. A portion of the net periodic benefit cost is capitalized within Exelon's Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts. The total amount recognized in OCI and regulatory assets in the table below does not include activity related to net periodic cost, employer contributions, and changes in the Federal subsidy receivable.

	Pension Benefits			Other Postretirement Benefits		
	2008	2007	2006	2008	2007	2006
Components of net periodic benefit cost:						
Service cost	$ 163	$ 163	$ 157	$ 108	$ 106	$ 99
Interest cost	635	603	562	208	192	183
Expected return on assets	(836)	(816)	(817)	(121)	(115)	(105)
Amortization of:						
Transition obligation (asset)	—	—	—	10	10	9
Prior service cost (credit)	15	16	16	(57)	(56)	(91)
Actuarial loss	127	148	149	53	63	87
Curtailment/settlement charges	9	5	6	—	—	—
Special termination benefits	—	1	3	—	—	—
Net periodic benefit cost	$ 113	$ 120	$ 76	$ 201	$ 200	$ 182
Changes in plan assets and benefit obligations recognized in OCI and regulatory assets:						
Current year actuarial (gain) loss	$3,432	$ 127	$ —	$ 495	$(109)	$ —
Amortization of actuarial gain (loss)	(127)	(148)	—	(53)	(63)	—
Current year prior service cost (credit)	16	—	—	—	—	—
Amortization of prior service (cost) credit	(15)	(16)	—	57	56	—
Amortization of transition asset (obligation)	—	—	—	(10)	(10)	—
Settlements	(9)	(5)	—	—	—	—
Change in additional minimum liability	—	—	1,138	—	—	—
Total recognized in OCI and regulatory assets	$3,297	$ (42)	$1,138	$ 489	$(126)	$ —

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, 2008 and 2007, respectively, for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	As of December 31,		As of December 31,	
	2008	2007	2008	2007
Transition obligation	$ —	$ —	$ 38	$ 48
Prior service cost (credit)	130	129	(166)	(223)
Actuarial loss	6,135	2,839	1,270	828
Total [(a)]	$6,265	$2,968	$1,142	$ 653

(a) Of the $6,265 million related to pension benefits, $4,023 million and $2,242 million are included in accumulated other comprehensive income and regulatory assets, respectively, as of December 31, 2008. Of the $1,142 million related to other postretirement benefits, $555 million and $587 million are included in accumulated other comprehensive income and regulatory assets, respectively, as of December 31, 2008. Of the $2,968 million related to pension benefits, $1,954 million and $1,014 million are included in accumulated other comprehensive income and regulatory assets, respectively, as of December 31, 2007. Of the $653 million related to other postretirement benefits, $310 million and $343 million are included in accumulated other comprehensive income and regulatory assets, respectively, as of December 31, 2007.

The following table provides the components of Exelon's accumulated other comprehensive income and regulatory assets as of December 31, 2008 (included in the table above) that are expected to be amortized as components of periodic benefit cost in 2009. These estimates are subject to the completion of a valuation report of Exelon's pension and other postretirement benefit obligations. This valuation report will reflect actual census data as of January 1, 2009 and actual claims activity as of December 31, 2008 and is expected to be completed by the first quarter of 2009.

	Pension Benefits	Other Postretirement Benefits
Transition obligation	$—	$ 10
Prior service cost (credit)	14	(56)
Actuarial loss	196	98
Total [(a)]	$210	$ 52

(a) Of the $210 million related to pension benefits, $129 million and $81 million are included in accumulated other comprehensive income and regulatory assets, respectively, as of December 31, 2008. Of the $52 million related to other postretirement benefits, $24 million and $28 million are included in accumulated other comprehensive income and regulatory assets, respectively, as of December 31, 2008.

Assumptions

The following weighted average assumptions were used to determine the benefit obligations for all the plans at December 31, 2008, 2007 and 2006:

	Pension Benefits			Other Postretirement Benefits		
	2008 [(a)]	2007	2006	2008 [(a)]	2007	2006
Discount rate	6.09%	6.20%	5.90%	6.09%	6.20%	5.85%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Mortality table	IRS required mortality table for 2009 funding valuation	IRS required mortality table for 2008 funding valuation	RP 2000 with 10-year projection of mortality improvements	IRS required mortality table for 2009 funding valuation	IRS required mortality table for 2008 funding valuation	RP 2000 with 10-year projection of mortality improvements
Health care cost trend on covered charges	N/A	N/A	N/A	7.5% decreasing to ultimate trend of 5.0% in 2014	8.00% decreasing to ultimate trend of 5.0% in 2014	9.00% decreasing to ultimate trend of 5.0% in 2012

(a) Assumptions used to determine year-end 2008 benefit obligations are the assumptions used to estimate the 2009 net periodic benefit cost.

The following weighted average assumptions were used to determine the net periodic benefit costs for all the plans for the years ended December 31, 2008, 2007 and 2006:

	Pension Benefits			Other Postretirement Benefits		
	2008	2007	2006	2008	2007	2006
Discount rate	6.20%	5.90%	5.60%	6.20%	5.85%	5.60%
Expected return on plan assets	8.75%	8.75%	9.00%	7.80% [a]	7.85% [a]	8.15% [a]
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Mortality table	IRS required mortality table for 2008 funding valuation	RP 2000 with 10-year projection of mortality improvements	RP 2000 without projection of mortality improvements	IRS required mortality table for 2008 funding valuation	RP 2000 with 10-year projection of mortality improvements	RP 2000 without projection of mortality improvements
Health care cost trend on covered charges	N/A	N/A	N/A	8.00% decreasing to ultimate trend of 5.0% in 2014	9.00% decreasing to ultimate trend of 5.0% in 2012	8.00% decreasing to ultimate trend of 5.0% in 2010

(a) Not applicable for the AmerGen-sponsored other postretirement benefits plan as this plan does not have any plan assets.

Assumed health care cost trend rates have a significant effect on the costs reported for the health care 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 2008 total service and interest cost components	$ 49
on postretirement benefit obligation at December 31, 2008	431
Effect of a one percentage point decrease in assumed health care cost trend	
on 2008 total service and interest cost components	(40)
on postretirement benefit obligation at December 31, 2008	(358)

Plan Assets

In managing its pension and postretirement plan assets, Exelon and former AmerGen utilize a diversified, strategic asset allocation to efficiently and prudently generate investment returns that will meet the objectives of the investment trusts that hold the plan assets. Asset / liability studies are utilized to determine the specific asset allocations for the trusts. In general, Exelon's and former AmerGen's investment strategy reflects the belief that over the long term, equities are expected to outperform fixed-income investments. The long-term nature of the pension and other postretirement benefit obligations makes the related trusts well-suited to bear the risk of added volatility associated with equity securities, and, accordingly, the asset allocations of the trusts usually reflect a higher allocation to equities (approximately 60%) as compared to fixed-income securities (approximately 40%). On a quarterly basis, Exelon reviews the actual asset allocations and follows a rebalancing procedure in order to remain within an allowable range, as defined by its policy, of these targeted percentages. Non-U.S. equity securities are used to diversify some of the volatility of the U.S. equity market while providing comparable long-term returns. Alternative asset classes, which are included in the equity securities and real estate asset categories below, may be utilized for additional diversification and return potential when appropriate. In the pension trusts, Exelon generally maintains approximately 10% of its plan assets in alternative asset classes. Exelon's and former AmerGen's investment guidelines limit the amount of allowed exposure to investments in more volatile sectors and limit concentrations based on established criteria.

The majority of the benefit plans participate in a securities lending program with the trustees of the plans' investment trusts. The program authorizes the trustee of the particular trust to lend securities, which are assets of the plan, to approved borrowers. The trustees require borrowers, pursuant to a security lending agreement, to deliver collateral to secure each loan. The loaned securities 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, which are adjusted daily, must be maintained at a level no less than 100% of the market

value of borrowed securities. Cash collateral received is invested in collateral funds comprised primarily of short-term investment vehicles. Collateral may not be sold or re-pledged by the trustees, however, the borrowers may sell or re-pledge the loaned securities. Exelon's benefit plans bear the risk of loss with respect to unfavorable changes in the fair value of the invested cash collateral. Such losses may result from a decline in the fair value of specific investments or due to liquidity impairments resulting from current market conditions. Losses recognized by the trust have not been material during the years ended December 31, 2008 and 2007. Management continues to monitor the performance of the invested collateral and work closely with the trustees to limit any potential losses.

Exelon, the trustees and the borrowers have the right to terminate the lending agreement at any time. In the event of termination, the borrowers must return the loaned securities or surrender the collateral. In the fourth quarter of 2008, Exelon decided to end its participation in the securities lending program. However, Exelon has chosen to initiate a gradual withdrawal of the trusts' investments in order to minimize potential losses due to the absence of liquidity in the market. Currently, the weighted average maturity of the securities within the collateral funds is approximately 7.5 months. Exelon's withdrawal from the securities lending program, based on the maturities of securities within the collateral funds, is expected to result in the return of approximately 70% of its loaned securities (in terms of value) by the end of 2009, 94% by the end of 2010, and the return of the remaining securities by the end of 2012.

The fair value of securities on loan was approximately $269 million and $689 million at December 31, 2008 and 2007, respectively. The fair value of the cash and non-cash collateral received for these loaned securities was $274 million at December 31, 2008, and $706 million at December 31, 2007. 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.

In selecting the expected rate of return on plan assets, Exelon considers historical returns for the types of investments that its plans hold in addition to expectations regarding future returns. Historical returns and volatilities are modeled to determine asset allocations that best meet the objectives of the investment trusts that hold the plan assets. A change in the strategy of the asset allocations could significantly impact the expected rate of return on plan assets.

Exelon's and former AmerGen's pension plan weighted average asset allocations at December 31, 2008 and 2007 and target allocation for 2008 were as follows:

Asset Category	Target Allocation at December 31, 2008	Percentage of Plan Assets at December 31, 2008	Percentage of Plan Assets at December 31, 2007
Equity securities	60-65%	53%	59%
Debt securities	35-40	42	36
Real estate	0-5	5	5
Total		100%	100%

Exelon's other postretirement benefit plan weighted average asset allocations at December 31, 2008 and 2007 and target allocation for 2008 were as follows:

Asset Category	Target Allocation at December 31, 2008	Percentage of Plan Assets at December 31, 2008	Percentage of Plan Assets at December 31, 2007
Equity securities	60-65%	58%	62%
Debt securities	35-40	42	37
Real estate	—	—	1
Total		100%	100%

Exelon's and AmerGen's defined benefit pension plans and postretirement benefit plans do not directly hold shares of Exelon common stock.

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans as of December 31, 2008 were:

	Pension Benefits	Other Postretirement Benefits [a]
2009	$ 647	$ 178
2010	619	188
2011	620	198
2012	634	205
2013	663	213
2014 through 2018	3,713	1,214
Total estimated future benefits payments through 2018	$6,896	$2,196

(a) Estimated future benefit payments do not reflect an anticipated Federal subsidy provided through the Prescription Drug Act. The Federal subsidies to be received by Exelon in the years 2009, 2010, 2011, 2012, 2013 and from 2014 through 2018 are estimated to be $9 million, $10 million, $11 million, $12 million, $14 million and $86 million, respectively.

Contributions

Exelon expects to contribute approximately $329 million to the benefit plans in 2009, of which Generation, ComEd and PECO expect to contribute $153 million, $72 million and $60 million, respectively. Exelon's expected 2009 benefit plan contributions of $329 million includes $218 million of minimum required pension (including discretionary contributions to avoid benefit restrictions) and other postretirement contributions and $111 million of discretionary contributions. These estimates are subject to the completion of a valuation report of Exelon's pension and other postretirement benefit obligations. This valuation report will reflect actual census data as of January 1, 2009 and claims activity as of December 31, 2008.

401(k) Savings Plan

Exelon, Generation, ComEd and PECO participate in a 401(k) savings plan sponsored by Exelon. The plan allows employees to contribute a portion of their pre-tax income in accordance with specified guidelines. Exelon, Generation, ComEd and PECO match 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	Exelon	Generation	ComEd	PECO
2008	$66	$33	$19	$7
2007	63	30	18	6
2006	60	30	17	6

15. Preferred Securities

At December 31, 2008 and 2007, Exelon was authorized to issue up to 100,000,000 shares of preferred stock, none of which were outstanding.

Preferred and Preference Stock of Subsidiaries

At December 31, 2008 and 2007, ComEd prior preferred stock and ComEd cumulative preference stock consisted of 850,000 shares and 6,810,451 shares authorized, respectively, none of which were outstanding.

At December 31, 2008 and 2007, cumulative preferred stock of PECO, no par value, consisted of 15,000,000 shares authorized and the outstanding amounts set forth below. Shares of preferred stock have full voting rights, including the right to cumulate votes in the election of directors.

		December 31,			
		2008	2007	2008	2007
	Redemption Price [a]	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 stock		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, 2008 and 2007, Exelon's common stock without par value consisted of 2,000,000,000 shares authorized and 658,154,642 and 660,879,188 shares outstanding, respectively. At December 31, 2008 and 2007, 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, 2008 and 2007, PECO's common stock without par value consisted of 500,000,000 shares authorized and 170,478,507 shares outstanding.

ComEd had 75,410 and 75,496 warrants outstanding to purchase ComEd common stock as of December 31, 2008 and 2007, 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, 2008 and 2007, 25,137 and 25,166 shares of common stock, respectively, were reserved for the conversion of warrants.

Share Repurchases

As part of its value return policy, Exelon uses share repurchases from time to time to return cash or balance sheet capacity to Exelon shareholders after funding maintenance capital and other commitments and in the absence of higher value-added growth opportunities. Repurchased shares are held as treasury shares and recorded at cost.

Share Repurchase Program. In April 2004, Exelon's Board of Directors approved a discretionary share repurchase program that allows Exelon to repurchase shares of its common stock on a periodic basis in the open market. The share repurchase program is intended to mitigate, in part, the dilutive effect of shares issued under Exelon's employee stock option plan and Exelon's Employee Stock Purchase Plan (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 has no specified limit on the number of shares that may be repurchased and no specified termination date. Any shares repurchased are held as treasury shares unless cancelled or reissued at the discretion of Exelon's management. During 2008 and 2007, 6.6 million shares and 0.6 million shares, respectively, of common stock were purchased under this share repurchase program for $500 million and $37 million, respectively.

On August 31, and December 19, 2007, Exelon's Board of Directors approved a share repurchase program for up to $1.25 billion and $500 million of Exelon's outstanding common stock, respectively. On September 4, 2007, Exelon entered into agreements with two investment banks to repurchase a total of $1.25 billion of Exelon's common shares under the first accelerated share repurchase (ASR) program. In addition, on February 26, 2008, Exelon entered into an agreement with an investment bank to repurchase a total of $500 million of Exelon's common shares under the second ASR program.

In accordance with EITF 99-7, "Accounting for an Accelerated Share Repurchase Program," Exelon accounts for each ASR program as two distinct transactions, as shares of common stock acquired in a treasury stock transaction and as a forward contract indexed to Exelon's own common stock. The ASR agreements include a pricing collar, which establishes a minimum and maximum number

of shares that can be repurchased. In September 2007 and February 2008, Exelon received the minimum number of shares, as determined by each of the ASR agreements, which amounted to 15.1 million shares and 5.8 million shares, respectively. These initial shares were recorded as treasury stock, at cost, for $1.17 billion and $436 million in September 2007 and February 2008, respectively.

Exelon accounts for the forward contract in accordance with EITF 00-19, "Accounting for Derivative Financial Instruments Indexed to, and Potentially Settled in, a Company's Own Stock," which requires the contract be initially measured at fair value, reported in permanent equity and subsequently accounted for based on its equity classification. The forward contract issued in September 2007 was settled in February 2008 when Exelon received 525,666 shares valued at $42 million. The ultimate settlement of this forward contract was based on changes in the price of Exelon's common stock from September 24, 2007 through the date of settlement. The forward contract issued in February 2008 was settled in May 2008 when Exelon received 260,086 shares valued at $22 million. The ultimate settlement of this forward contract was based on changes in the price of Exelon's common stock from February 29, 2008 through the date of settlement.

On September 2, 2008, Exelon's board of directors approved a share repurchase program for up to $1.5 billion of Exelon's outstanding common stock. Exelon management has 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, such as the proposed acquisition of NRG Energy, Inc.

Under the share repurchase programs, 34.8 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of December 31, 2008. During 2008 and 2007, Exelon repurchased 6.6 million shares and 15.7 million shares, respectively, of common stock under the share repurchase programs for $500 million and $1.2 billion, including the impact of the settlement of forward contracts, respectively.

Stock-Based Compensation Plans

Exelon grants stock-based awards through its Long-Term Incentive Plan (LTIP), which primarily includes performance share awards, stock options and restricted stock units. At December 31, 2008, there were approximately 23 million shares authorized for issuance under the LTIP. During the years ended December 31, 2008, 2007 and 2006, exercised and distributed stock-based awards were issued from authorized but unissued common stock shares.

The following table presents the stock-based compensation expense included in Exelon's Consolidated Statements of Operations during the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
Components of Stock-Based Compensation Expense	**2008**	**2007**	**2006**
Performance shares	$ 28	$ 76	$ 84
Stock options	24	34	39
Restricted stock units	20	13	3
Other stock-based awards	4	2	2
Total stock-based compensation included in operating and maintenance expense	76	125	128
Income tax benefit	(29)	(48)	(48)
Total after-tax stock-based compensation expense	$ 47	$ 77	$ 80

The following table presents stock-based compensation expense (pre-tax) during the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
Subsidiaries	**2008**	**2007**	**2006**
Generation	$38	$ 47	$ 48
ComEd	4	8	12
PECO	6	5	3
Other	28	65	65
Total	$76	$125	$128

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2008, 2007 and 2006.

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 recognized in accordance with FASB Statement No. 123 (revised 2004), "Share-Based Payment" (SFAS No. 123-R). 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, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	**2007**	**2006**
Realized tax benefit when exercised/distributed:			
Stock options	$59	$93	$68
Restricted stock units	4	7	9
Performance share awards	27	28	20
Stock deferral plan	10	25	2
Excess tax benefits included in other financing activities of Exelon's Consolidated Statement of Cash Flows:			
Stock options	$51	$77	$53
Restricted stock units	1	4	4
Performance share awards	2	1	2
Stock deferral plan	6	15	1

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. All stock options expire ten years from the date of grant. The vesting period of stock options outstanding as of December 31, 2008 generally ranged from three years to four years. The value of stock options at the date of grant is either amortized through expense or capitalized over the requisite service period using the straight-line method. For stock options granted to retirement-eligible employees, the value of the stock option is recognized immediately on the date of grant.

Exelon grants most of its stock options in the first quarter of each year. Stock options granted during the remaining quarters of 2008, 2007 and 2006 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, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
Dividend yield	2.73%	2.94%	3.20%
Expected volatility	29.30%	22.00%	25.50%
Risk-free interest rate	3.17%	4.71%	4.27%
Expected life (years)	6.25	6.25	6.25
Weighted average grant date fair value	$18.36	$13.05	$13.22

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, 2008:

	Shares	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
Balance of shares outstanding at December 31, 2007	13,950,698	$41.26		
Options granted	853,900	73.29		
Options exercised	(3,104,716)	34.73		
Options forfeited/cancelled	(358,154)	50.41		
Balance of shares outstanding at December 31, 2008	11,341,728	45.17	5.64	$145,247,858
Exercisable at December 31, 2008 [(a)]	8,389,991	41.47	5.08	133,504,417

(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, 2008, 2007 and 2006:

	Year Ended December 31,		
Stock Options Exercised	2008	2007	2006
Intrinsic value [(a)]	$147	$231	$170
Cash received for exercise price	108	186	171

(a) The difference between the market value on the date of exercise and the strike price.

The following table summarizes Exelon's nonvested stock option activity for the year ended December 31, 2008:

	Shares	Weighted Average Exercise Price (per share)
Nonvested at December 31, 2007 [a]	5,790,654	$47.61
Granted [b]	853,900	73.29
Vested [b]	(3,388,998)	45.52
Forfeited	(303,819)	57.33
Nonvested at December 31, 2008 [a]	2,951,737	$56.42

(a) Excludes 953,175 and 1,034,837 of stock options issued to retirement-eligible employees at December 31, 2008 and December 31, 2007, respectively as they are fully vested.
(b) Includes 297,300 of stock options issued to retirement eligible employees that vested immediately on the date of grant.

As of December 31, 2008, $16 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 2.04 years.

Restricted Stock Units

Exelon grants restricted stock units under the LTIP. Beginning in January 2007, Exelon began granting certain managers restricted stock units in lieu of stock options. Prior to 2007, Exelon utilized restricted stock units on a limited basis primarily to compensate executive management. The majority of Exelon's restricted stock units will be settled in common stock. In accordance with SFAS No. 123-R, 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. In accordance with SFAS No. 123-R, 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 either amortized through expense over the requisite service period using the straight-line method or capitalized. 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, 2008:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2007 [a]	683,128	$56.41
Granted	452,200	74.83
Distributed	(106,677)	57.62
Forfeited	(51,911)	56.00
Undistributed vested awards [b]	(77,230)	71.49
Nonvested at December 31, 2008[a]	899,510	$64.26

(a) Excludes 118,948 and 69,619 of restricted stock units issued to retirement-eligible employees at December 31, 2008 and December 31, 2007, respectively, as they are fully vested.
(b) Represents restricted stock units granted to retirement-eligible participants in 2008.

The weighted average grant date fair value of restricted stock units granted during the years ended December 31, 2008, 2007 and 2006 was $74.83, $63.89 and $55.26, respectively. As of December 31, 2008 and 2007, Exelon had obligations related to

outstanding restricted stock units not yet settled of $33 million and $18 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, 2008 and 2007, which are included in deferred credits and other liabilities in Exelon's Consolidated Balance Sheets. During the years ended December 31, 2008, 2007 and 2006, Exelon settled restricted stock units with fair value totaling $10 million, $18 million and $1 million, respectively. As of December 31, 2008, $32 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.36 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, 2008 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 comparator 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 twelve months ended December 31, 2008 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 accrued and 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 throughout the year of grant.

The following table summarizes Exelon's nonvested performance share awards activity for the year ended December 31, 2008:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2007 [(a)]	1,260,975	$59.24
Granted	844,940	72.89
Distributed	(680,471)	59.03
Forfeited	(135,194)	65.77
Undistributed vested awards [(b)]	(365,877)	70.48
Nonvested at December 31, 2008 [(a)]	924,373	$66.47

(a) Excludes 640,453 and 532,891 of performance share awards issued to retirement-eligible employees at December 31, 2008 and December 31, 2007, respectively, as they are fully vested.

(b) Represents performance share awards granted to retirement-eligible participants in 2008.

The weighted average grant date fair value of performance share awards granted during the years ended December 31, 2008, 2007 and 2006 was $72.89, $59.94 and $58.43, respectively. During the years ended December 31, 2008, 2007 and 2006, Exelon settled performance shares with a fair value totaling $69 million, $65 million and $49 million, respectively, of which $44 million, $39 million and $24 million was paid in cash, respectively. As of December 31, 2008, $14 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.83 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, 2008	2007
Current liabilities [(a)]	$28	$ 48
Deferred credits and other liabilities [(b)]	21	35
Common stock	26	27
Total	$75	$110

(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.

Stock Deferral Plan

Prior to January 1, 2007, Exelon management had the ability to defer the receipt of certain distributions of stock from Exelon's stock-based compensation programs into the Exelon Corporation Stock Deferral Plan. In December 2006, the Compensation Committee of Exelon's Board of Directors approved a proposal to discontinue deferrals to the deferred stock plan. Additionally, active participants in the plans were provided a one-time election to take a full distribution of all deferred stock in the third quarter of 2007. Exelon distributed 248,633 shares of Exelon common stock valued at $17 million and cash-settled 435,245 shares for $31 million on July 31, 2007 to the participants that elected to receive a lump sum distribution in the third quarter of 2007. At December 31, 2008 and 2007, Exelon has obligations at historical cost related to this plan of $11 million and $20 million, respectively, which are included in common stock in Exelon's Consolidated Balance Sheets.

Undistributed Gains / Losses of Equity Method Investments

Exelon, Generation and PECO had undistributed losses of equity method investments of $446 million, $3 million and $73 million, respectively, at December 31, 2008 and $497 million, $7 million and $57 million, respectively, at December 31, 2007. ComEd had less than $1 million in undistributed gains of equity method investments at December 31, 2008 and $67 million of undistributed losses of equity method investments at December 31, 2007. See Note 19—Supplemental Financial Information for additional detail on Exelon's equity method investments.

17. Earnings Per Share

Diluted earnings per share are calculated by dividing net income by the weighted average number of shares of common stock outstanding, including the dilutive impact of assumed exercises and distributions of Exelon's outstanding stock-based awards. The dilutive impact of Exelon's stock-based awards is primarily due to the assumed exercises of stock options but also includes the assumed distributions of performance shares and restricted stock units. The following table sets forth the computation of basic and diluted earnings per share and shows the effect of these stock-based awards on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	2008	2007	2006
Income from continuing operations	$2,717	$2,726	$1,590
Income from discontinued operations	20	10	2
Net income	$2,737	$2,736	$1,592
Average common shares outstanding—basic	658	670	670
Assumed exercises and/or distributions of stock-based awards	4	6	6
Average common shares outstanding—diluted	662	676	676

The number of stock-based awards not included in the calculation of diluted common shares outstanding due to their antidilutive effect was less than 1 million in 2008 and 2007, and 3 million for 2006.

18. Commitments and Contingencies

Nuclear Insurance

The Price-Anderson Act was enacted to limit the liability of nuclear reactor owners for claims that could arise from a single incident at any of the U.S. licensed nuclear facilities and to ensure the availability of funds for claims arising in the event of an incident. As of December 31, 2008, the current liability limit per incident was $12.52 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. As required by the Price-Anderson Act, Generation maintains a primary level of financial protection by carrying the maximum available amount of nuclear liability insurance (currently $300 million for each operating site) for claims that could arise in the event of an incident. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory participation in a secondary financial protection pool by the operators of all U.S. licensed reactors (currently 104 reactors) resulting in an additional $12.22 billion in funds available for claims. Participation in the financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the $300 million of the primary level insurance coverage. 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 claims. The Price-Anderson Act, as amended, requires an inflation adjustment be made at least once each 5 years. The last inflation adjustment was effective October 29, 2008.

Generation is a member of an industry mutual insurance company, Nuclear Electric Insurance Limited (NEIL), which 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 (except for Zion, which is $100 million). 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 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 $172 million per year for losses incurred at any plant insured by the insurance companies (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 $46 million per year (the retrospective premium obligation). NEIL may require financial assurance of the ability to satisfy the obligation to pay this assessment. 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 will require 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. As discussed above, the current aggregate annual retrospective premium obligation for Generation is $218 million.

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 new 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. Such losses could have a material adverse effect on Exelon's and Generation's financial condition, results of operations and liquidity.

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. 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, 2008, 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 as indicated in the following tables:

	Net Capacity Purchases [a]	Power Only Purchases [b]	Power Only Sales	Transmission Rights Purchases [c]
2009	$ 336	$190	$2,212	$ 9
2010	322	25	550	9
2011	331	30	163	9
2012	332	—	64	9
2013	211	—	31	6
Thereafter	1,791	—	—	—
Total	$3,323	$245	$3,020	$ 42

(a) Net capacity purchases include tolling agreements 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, 2008. Expected payments include certain capacity charges which are contingent on plant availability.

(b) Excludes renewable 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.

On April 4, 2007, Generation agreed to sell its rights to 942 MWs of capacity, energy, and ancillary services supplied from its existing long-term contract with Tenaska Georgia Partners, LP through a tolling agreement with Georgia Power, a subsidiary of Southern Company, commencing June 1, 2010 and lasting for 20 years. The transaction was approved by the Georgia Public Service Commission (GPSC) in October of 2007. Exelon and Generation recognized a non-cash after-tax loss of approximately $72 million during the fourth quarter of 2007, which is included in purchased power on Exelon's and Generation's Consolidated Statements of Operations. The transaction provides Generation with approximately $43 million in annual revenue in the form of capacity payments over the term of the tolling agreement.

On October 15, 2007, Generation entered into an agreement (Termination Agreement) with State Line Energy, L.L.C. (State Line), an indirect wholly owned subsidiary of Dominion Resources Inc., to terminate the Power Purchase Agreement dated as of April 17, 1996 (as amended, the State Line PPA) between State Line and Generation relating to the State Line generating facility in Hammond, Indiana. Under the State Line PPA, Generation controlled 515 MW of electric energy and capacity from the State Line facility. FERC approved the Termination Agreement on October 18, 2007. The conditions to the effectiveness of the Termination Agreement were subsequently satisfied and Generation recorded income of approximately $223 million in the fourth quarter of 2007, which is included in operating revenues on Exelon's and Generation's Consolidated Statements of Operations.

Beginning in January 2007, ComEd began procuring all of its energy requirements for retail customers from market sources pursuant to the ICC-approved procurement auction in 2006 or from the PJM spot market. The Settlement Legislation enacted in Illinois in 2007 established a new competitive process for Illinois utilities to procure electricity but did not affect the contracts resulting from the 2006 auction. The new competitive process for procurement will be managed by the IPA, under the oversight of the ICC, in accordance with electricity supply procurement plans approved by the IPA. In March 2008, ComEd entered into procurement contracts to enable ComEd to meet a portion of its customers' electricity requirements for the period from June 2008 to May 2009. See Note 3—Regulatory Issues for further information. These contracts result in ComEd's energy commitments of $130 million for 2009.

PECO has a long-term PPA with Generation under which PECO obtains all of its electric supply from Generation through 2010. The price for this electricity is essentially equal to the energy revenues earned from customers as specified by PECO's 1998 restructuring settlement mandated by the Competition Act. Subsequent to 2010, PECO expects to procure all of its electric supply from market sources, which could include Generation.

ComEd and PECO are also subject to requirements established by the Illinois Settlement Legislation and the AEPS Act, respectively, related to alternative energy resources. See Note 3—Regulatory Issues 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. As of December 31, 2008, these net commitments were as follows:

		Expiration within			
	Total	2009	2010-2011	2012-2013	2014 and beyond
Generation	$5,999	$1,168	$1,615	$1,107	$2,109
PECO	505	157	159	78	111

Commercial Commitments

Exelon's commercial commitments as of December 31, 2008, representing commitments potentially triggered by future events, were as follows:

		Expiration within			
	Total	2009	2010-2011	2012-2013	2014 and beyond
Letters of credit (non-debt) [a]	$ 430	$430	$—	$ —	$ —
Letters of credit (long-term debt)—interest coverage [b]	18	7	11	—	—
Surety bonds [c]	88	7	—	—	81
Performance guarantees [d]	296	200	—	95	1
Energy marketing contract guarantees [e]	207	162	40	—	5
Nuclear insurance premiums [f]	1,997	—	—	—	1,997
Lease guarantees [g]	131	—	3	9	119
2007 City of Chicago Settlement [h]	14	8	4	2	—
Midwest Generation Capacity Reservation Agreement guarantee [i]	14	4	8	2	—
Rate relief commitments–Settlement Legislation [j]	152	128	24	—	—
Total commercial commitments	$3,347	$946	$ 90	$108	$2,203

(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, 2008, Exelon had $225 million of outstanding letters of credit (non-debt) issued under its $6.6 billion credit agreements. Guarantees of $10 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 $566 million at Generation and $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—Represent 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.
(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 $18 million and $23 million was paid in December 2008 and 2007, respectively. See Note 3—Regulatory Issues for additional details on the City of Chicago Settlement.
(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. Under FIN 45, $1 million is included as a liability on Exelon's Consolidated Balance Sheets at December 31, 2008 related to this guarantee.
(j) See Note 3—Regulatory Issues for additional detail related to Generation's and ComEd's rate relief commitments.

Construction Commitments

Under their operating agreements with PJM, ComEd and PECO are committed to construct transmission facilities. 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	2009	2010	2011	2012	2013
ComEd	$188	$71	$54	$19	$18	$26
PECO	153	52	33	29	16	23

Renewable Energy Credits

In May 2008, ComEd entered into contracts for the procurement of renewable energy credits totaling approximately $19 million, of which $11 million was purchased in 2008 and $8 million will be purchased in 2009. In August 2008, PECO entered into a contract for the procurement of renewable energy credits totaling approximately $6 million, of which approximately $1 million was purchased in 2008 and $5 million will be purchased between 2009 and 2012. See Note 3—Regulatory Issues for more information.

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, 2008 were:

2009	$ 68
2010	63
2011	61
2012	61
2013	56
Remaining years	453
Total minimum future lease payments	$762 [(a)]

(a) Excludes Generation's tolling agreements and other capacity contracts that are accounted for as contingent operating lease payments.

Exelon's rental expense under operating leases was as follows:

	Exelon [(a)]
2008	$867
2007	869
2006	776

(a) Includes Generation's tolling agreements 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 tolling agreements and other capacity contracts totaled $787 million, $785 million and $698 million during 2008, 2007 and 2006, 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. These indemnifications and guarantees are being accounted for under the provisions of FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others". 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, 2008, Generation had $8 million in guarantee liabilities remaining. The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy was approximately $175 million at December 31, 2008.

Indemnifications Related to Sale of Termoeléctrica del Golfo (TEG) and Termoeléctrica Peñoles (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 guaranty 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 guaranty that is not otherwise subject to a dispute resolution process. Generation's maximum obligation under the guaranty is $95 million. Generation has not recorded a liability associated with this guarantee. The exposures covered by this guaranty expired in part during 2008.

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. ComEd and PECO have identified 42 and 27 sites, respectively, where former manufactured gas plant (MGP) activities have or may have resulted in actual site contamination. For almost all of these sites, ComEd or PECO is one of several Potentially Responsible Parties (PRPs) which may be responsible for ultimate remediation of each location. Of the 42 sites identified by ComEd, the Illinois Environmental Protection Agency has approved the clean up of nine sites and of the 27 sites identified by PECO, the Pennsylvania Department of Environmental Protection (PA DEP) has approved the cleanup of 16 sites. Of the remaining sites identified by ComEd and PECO, 22 and 7 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 2020, respectively. 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 Nicor Gas Company, a subsidiary of Nicor Inc. (Nicor), are parties to an interim agreement under which they cooperate in remediation activities at 38 former MGP sites for which ComEd or Nicor, or both, may have responsibility. Under the interim agreement, costs are split evenly between ComEd and Nicor pending their final agreement on allocation of costs at each site, but either party may demand arbitration if the parties cannot agree on a final allocation of costs. For most of the sites, the interim

agreement contemplates that neither party will pay less than 20%, or more than 80% of the final costs for each site. On January 3, 2008, ComEd and Nicor executed a definitive written agreement on the allocation of costs for the MGP sites, which is contingent upon ICC approval. Through December 31, 2008, ComEd has incurred approximately $127 million associated with remediation of the sites in question. ComEd's accrual as of December 31, 2008 for these environmental liabilities reflects the cost allocations contemplated in the agreement.

Based on the final order received in ComEd's Rate Case, beginning in 2007, ComEd is recovering from customers a provision for environmental costs for the remediation of former MGP facility sites, for which ComEd has recorded a regulatory asset. Pursuant to a PAPUC order, PECO is currently recovering from customers a provision for environmental costs annually for the remediation of former MGP facility sites, for which PECO has recorded a regulatory asset. See Note 19—Supplemental Financial Information for additional information regarding regulatory assets and liabilities.

During the third quarter of 2008, ComEd completed an annual study of its future estimated remediation requirements. The results of this study indicated that additional remediation would be required at certain sites; therefore ComEd increased its reserve and regulatory asset by $21 million. During the fourth quarter of 2008, PECO completed an annual study of its future estimated remediation requirements. The results of this study indicated that an additional remediation would be required at certain sites; therefore PECO increased its reserve and regulatory asset by $14 million. Settlement rates support the expenditure, on an annual basis, of $3.5 million for the remediation of PECO's former MGP sites based on an 8-year estimated remaining duration of PECO's MGP remediation program.

As of December 31, 2008 and 2007, Exelon had accrued the following undiscounted amounts for environmental liabilities in Other Deferred Credits and Other Liabilities within its Consolidated Balance Sheets:

December 31,	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
2008	$151	$127
2007	132	110

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 United States Environmental Protection Agency (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 National Pollutant Discharge Elimination System (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. Since promulgation of the rule, Generation has been evaluating compliance options at its affected plants and meeting interim compliance deadlines.

On January 25, 2007, the U.S. Second Circuit Court of Appeals issued its opinion in a challenge to the final Phase II rule brought by environmental groups and several states. 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. The court remanded the rule back to the EPA for revisions consistent with the court's opinion. By its action, the court invalidated compliance measures. The utility industry supported those compliance measures because they were cost-effective and provided existing plants with needed flexibility in selecting the compliance option appropriate to its location and operations. For example, the court found that environmental restoration does not qualify as a compliance option and site-specific compliance variances based on a cost-benefit analysis are impermissible. The court's opinion has created significant uncertainty about the specific nature, scope and timing of the final compliance requirements. On July 9, 2007, the EPA formally suspended the Phase II rule due to the uncertainty about the specific compliance requirements created by the court's remand of significant provisions of the rule. Until the EPA finalizes the rule on remand (which could take several years), 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.

On April 14, 2008, the U.S. Supreme Court granted a petition filed by the industry parties on the issues of whether Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. The U.S. Supreme Court held oral arguments on the appeal on December 2, 2008, and a decision is expected in 2009. Should the U.S. Supreme Court find that the EPA can utilize the cost-benefit compliance option, this finding would provide the utility industry with flexible and cost-effective alternatives.

Due to the regulatory and litigation uncertainties, Generation cannot estimate the effect that compliance with the Phase II rule requirements will have on the operation of its generating facilities and its future results of operations, financial condition and cash flows. If the final rule, or interim state requirements under best professional judgment, has performance standards that require the reduction of cooling water intake flow at the plants consistent with closed loop cooling systems, then there could be a material impact on the operation of the facilities and Exelon's and Generation's future results of operations, cash flows and financial positions.

In a draft permit issued on July 19, 2005, as part of the pending NPDES permit renewal process for Oyster Creek, the NJDEP preliminarily determined that closed-cycle cooling and environmental restoration are the only viable compliance options for Section 316(b) compliance at Oyster Creek. In light of the suspension of the Phase II rule by the EPA, the NJDEP advised AmerGen that it will issue a new draft permit, and reiterated its preference for cooling towers as the best technology available in the exercise of its best professional judgment. Since the final permit has not been issued, Oyster Creek has continued to operate under the 1999 permit. Generation cannot predict with any certainty how the NJDEP will implement its best professional judgment. Generation has not made a determination regarding how it will comply with the Section 316(b) regulations and must first evaluate the final regulations issued by the EPA as a result of the decision of the U.S. Court of Appeals for the Second Circuit, discussed above. In addition, the cost required to retrofit Oyster Creek with closed cycle cooling could be material and could therefore negatively impact Generation's decision to operate the plant after the 316(b) matter is ultimately resolved.

In June 2001, the NJDEP issued a renewed NDPES 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, NDPES permit while the NDPES permit renewal application is being reviewed. If application of the final 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 and could result in increased depreciation expense related to the retrofit investment.

Nuclear Generating Station Groundwater. On December 16, 2005 and February 27, 2006, the Illinois EPA issued violation notices to Generation alleging violations of state groundwater standards as a result of historical discharges of liquid tritium from a line at the Braidwood Nuclear Generating Station (Braidwood).

In November 2005, Generation discovered that spills from the line in 1996, 1998 and 2000 have resulted in a tritium plume in groundwater that is both on and off the plant site. Levels in portions of the plume exceed Federal limits for drinking water. However, samples from drinking water wells on property adjacent to the plant showed that, with one exception, tritium levels in these wells were at levels that naturally occur. The tritium level in one drinking water well was elevated above levels that occur naturally, but was significantly below the state and Federal drinking water standards, and Generation believes that this level posed no threat to human health. Generation has investigated the causes of the releases and has taken the necessary corrective actions to prevent another occurrence. Generation notified the owners of 14 potentially affected adjacent properties that, upon sale of their property, Generation will reimburse the owners for any diminution in property value caused by the tritium release. As of December 31, 2008, Generation had purchased four of the 14 adjacent properties.

On October 11, 2006, a resident owning property near the plant filed a lawsuit in the U.S. District Court for the Northern District of Illinois against Exelon, Generation and ComEd alleging property contamination and seeking damages for diminished property value. This was the only remaining lawsuit brought by local residents. Both Generation and Exelon have been dismissed from this lawsuit.

On March 16, 2006, the Attorney General of the State of Illinois and the State's Attorney for Will County, Illinois filed a civil enforcement action against Exelon, Generation and ComEd in the Circuit Court of Will County relating to the releases of tritium discussed above and alleging that there have been tritium and other non-radioactive wastes discharged from Braidwood in violation of Braidwood's NPDES permit, the Illinois Environmental Protection Act and regulations of the Illinois Pollution Control Board. The

lawsuit seeks the maximum civil penalties allowed, injunctive relief relating to the discontinuation of the liquid tritium discharge line until additional court order, soil and groundwater testing, prevention of future releases and off-site migration, and provision of potable drinking water to area residents. On May 24, 2006, the Circuit Court entered an order resulting in Generation commencing remediation efforts in June 2006 for tritium in groundwater off of plant property. Any civil penalty will not be determined until the consent decree is finalized. Generation is unable to determine the amount of the penalty that will be sought.

Generation detected small underground tritium leaks at the Dresden Nuclear Generating Station (Dresden) and at the Byron Nuclear Generating Station (Byron) in 2006. Neither of these discharges occurred outside the property lines of the plant, nor does Generation believe either of these matters poses health or safety threats to employees or to the public. Generation identified the source of the leaks and implemented repairs. On March 31, 2006 and April 12, 2006, the Illinois EPA issued an NOV to Generation in connection with the Dresden and Byron leaks. The Illinois EPA has rejected the remediation plans submitted by Generation for each station and is currently pursuing legal action against Generation.

Generation is discussing the violation notices and Illinois Attorney General civil enforcement matters for Braidwood, Dresden and Byron, discussed above, with the Illinois EPA, the Illinois Attorney General and the State's Attorney for the Counties in which the plants are located. Generation believes that appropriate reserves have been recorded for State of Illinois fines and remediation costs in accordance with SFAS No. 5 as of December 31, 2008 and 2007.

On April 10, 2008, the Illinois EPA issued an NOV to Generation alleging that the Quad Cities Nuclear Generating Station (Quad Cities) violated state groundwater quality standards for tritium. The NOV related to increases in monitored tritium levels within the property lines of the plant in October 2007, which Generation had reported to the Illinois EPA. Quad Cities conducted an investigation and responded to the NOV, setting forth the actions taken to identify and correct the source of the leak. None of the areas with increased tritium levels is outside the property lines of the plant, and Generation does not believe this matter posed health or safety threats to employees or to the public. The NOV has now been resolved, and no penalties were imposed or further response action required.

Exelon, Generation or ComEd cannot determine the outcome of the above-described matters but believe their ultimate resolution should not, after consideration of reserves established, have a significant impact on Exelon's, Generation's or ComEd's financial position, results of operations or cash flows.

Cotter Corporation. The 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 incurred by Cotter as a result of 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. The current estimated cost of the anticipated remediation for the site increased from $24 million to $36 million in the fourth quarter of 2008, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount within this estimated cost range to cover its anticipated share of the liability.

Air. During March 2005, the EPA finalized several new rulemakings designed to reduce power plant emissions of SO_2, NO_x, and mercury. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the Clean Air Interstate Rule (CAIR), which had been promulgated by the EPA to reduce power plant emissions of SO_2 and NO_x. On September 25, 2008, EPA petitioned the Court for re-hearing of the CAIR decision. In response to the September petition, on December 23, 2008, the Court elected to remand the CAIR to EPA, without invalidating the entire rulemaking, so that EPA may remedy "CAIR's flaws" in accordance with the Court's July 11, 2008 opinion. This decision allows the CAIR to remain in effect until it is replaced by a rule consistent with the Court's July 11 opinion. In its December opinion, the Court elected not to establish a particular schedule for EPA to revise its rulemaking; however, the Court did indicate that its remand did not represent an indefinite stay of the Court's original opinion and that petitioners retained the right to bring a mandamus petition to the Court in the event that EPA fails to modify its CAIR regulations as directed by the Court. At this time, Exelon is unable to predict the exact timeline or approach that will be utilized by EPA to revise its CAIR regulation, how long the current CAIR program will remain in effect, or what steps individual states may take in response to the CAIR situation. Due to the uncertainty as to any of these potential outcomes, Exelon cannot estimate the effect of the decision on its operations and its future competitive position, results of operations, earnings, cash flows and financial position.

In a separate rulemaking issued in March 2005, the EPA finalized the Clean Air Mercury Rule (CAMR), which is a national program to cap mercury emissions from coal-fired generating units starting in 2010, with a second reduction in the mercury emission cap level scheduled for 2018. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CAMR on the basis that the EPA had failed to properly de-list mercury as a hazardous air pollutant 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 hazardous air pollutants. The U.S. Supreme Court is considering a petition from the Utility Air Regulatory Group to review the U.S. Court of Appeals' decision (a similar petition by the EPA is likely to be withdrawn). In addition to regulation at the national level, Exelon had been subject to more stringent mercury regulation (PA Mercury Rule) enacted in 2006 at the state level in Pennsylvania. However, on January 30, 2009, the Commonwealth Court of Pennsylvania ruled that the PA Mercury Rule is unlawful and invalid and enjoined the state from continued implementation and enforcement of the rule. As such, the nature and extent of regulatory controls on mercury emissions at coal-fired power plants will not be determined until the Federal and state regulations are finalized upon the completion of court appeals and any subsequent agency rulemaking.

Notice and Finding of Violation Related to Electric Generation Stations. On August 6, 2007, ComEd received an NOV, addressed to it and Midwest Generation, LLC (Midwest Generation) from the EPA, alleging that ComEd and Midwest Generation have violated and are continuing to violate several provisions of the Federal 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 EPA requested information related to the stations in 2003, and ComEd has been cooperating with the EPA since then. The NOV states that the 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 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 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 NOV, 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 a loss is not probable or estimable and accordingly, have not recorded a reserve for the NOV.

On January 14, 2009, Generation received an NOV, addressed to it, the other owners of Keystone Generating Station (Keystone) and Reliant Energy Northeast Management Company (the operator of Keystone) from the EPA, alleging past and continuing violations of several provisions of the Federal Clean Air Act as a result of the modification and/or operation of Keystone, as well as two other stations currently owned and operated by Reliant Energy in which Generation has no ownership interest. Generation has been cooperating with the EPA since the time of requests for information in 2000, 2001 and 2007. The NOV states that the 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 EPA's enforcement authority under the Clean Air Act. At this time, Exelon and Generation are unable to predict the ultimate resolution of the claims alleged in the NOV or the costs that might be incurred by Generation; however, Exelon and Generation have concluded that a loss is not probable or estimable and, accordingly, have not recorded a reserve for the NOV.

Voluntary Greenhouse Gas Emissions Reductions. Exelon announced on May 6, 2005 that it has established a voluntary goal to reduce its greenhouse gas (GHG) emissions by 8% from 2001 levels by the end of 2008. The 8% reduction goal represents a decrease of an estimated 1.3 million metric tons of GHG emissions. Exelon has incorporated recognition of GHG emissions and their potential cost into its business analyses as a means to promote internal investment in climate-reducing activities. Exelon made this pledge under the United States EPA's Climate Leaders program, a voluntary industry-government partnership addressing climate change. As of December 31, 2008, Exelon had achieved its 2008 voluntary GHG reduction goal through its planned GHG management efforts, including the previous closure of older, inefficient fossil power plants, reduced leakage of SF_6, increased use of renewable energy and its current energy efficiency initiatives. The cost of achieving the voluntary GHG emissions reduction goal did not have a material effect on Exelon's future competitive position, results of operations, earnings, financial position or cash flows.

On July 15, 2008, Exelon announced a comprehensive environmental plan. The plan, Exelon 2020, details an enterprise-wide approach and a host of initiatives being pursued by Exelon to reduce Exelon's greenhouse gas emissions and that 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 greenhouse gas emissions per year by 2020, which is more than Exelon's total current carbon footprint.

Through Exelon 2020, Exelon is pursuing three broad strategies: reducing or offsetting its own carbon footprint, helping customers and communities reduce their greenhouse gas emissions, and offering more low-carbon electricity in the marketplace. Initiatives to reduce Exelon's own carbon footprint include reducing building energy consumption by 25%, reducing the 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 greenhouse gas emissions include ComEd's new portfolio of energy efficiency programs, a similar portfolio of energy efficiency programs in development at PECO to meet the requirements of the recently enacted PA 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. Finally, Exelon will offer more low-carbon electricity in the marketplace by increasing its investment in renewable power, adding capacity to existing nuclear plants through uprates, and through the potential addition of new low-carbon natural gas and nuclear generation.

Exelon is committed to achieving the Exelon 2020 goal but also recognizes that the changing economy and market outlook may require it to refine or alter the timing of some of these initiatives and update the 2020 roadmap accordingly. The anticipated economic stimulus package currently being considered in Congress and other new energy policies will also likely have an impact on initiatives under the plan.

Exelon has incorporated Exelon 2020 into the company's 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. 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.

On April 2, 2007, the U.S. Supreme Court issued a decision in the case of Massachusetts v. U. S. Environmental Protection Agency holding that CO_2 and other GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. The case was remanded to the EPA for additional rulemaking to determine whether GHG emissions may reasonably be anticipated to endanger public health or welfare, or in the alternative provide a reasonable explanation why GHG emissions should not be regulated. Possible outcomes from this decision include regulation of GHG emissions from manufacturing plants, including electric generation, transmission and distribution facilities, under a new EPA rule and Federal or state legislation. In response to the Supreme Court decision, on July 11, 2008, the EPA issued an Advance Notice of Proposed Rulemaking (ANPR) and is currently considering public comments made on legal and regulatory analyses and policy alternatives regarding GHG effects and regulation under the Clean Air Act. In issuing the ANPR, the EPA deferred any regulation of GHGs under the Clean Air Act. The issue of GHG regulation will likely be addressed in the new presidential administration, whether by regulation under the Clean Air Act or by new and comprehensive legislation. Exelon continues to support the enactment, through Federal legislation, of a cap-and-trade system for GHG emissions that is mandatory, economy-wide and designed in a way to limit potential harm to the economy and the competitiveness of the manufacturing base in the U.S. Due to the uncertainty as to any of these potential outcomes, Exelon cannot estimate the effect of the decision on its operations and its future competitive position, results of operations, earnings, cash flows and financial position.

Air Quality Regulation. Pursuant to EPA regulations that will impose limits on certain future emissions by generation stations, the co-owners of the Keystone generating station formally approved on June 30, 2006 a capital plan to install SO_2 scrubbers at the station for which Exelon's share of the estimated project costs, based on its 20.99% ownership interest, would be approximately $140 million over the life of the project. For the years ended December 31, 2008, 2007, and 2006, total costs incurred, including capitalized interest**,** were $71 million, $27 million and $4 million, respectively. Exelon anticipates spending approximately $38 million in 2009 related to this project. The Keystone SO_2 scrubbers are expected to be operational by the end of 2009.

Litigation and Regulatory Matters

Real Estate Tax Appeals. PECO and Generation each has been challenging real estate taxes assessed on certain nuclear plants. PECO has appealed local real estate assessments for 1998 and 1999, and Generation is involved in real estate tax appeals for 2000 through 2004, regarding the valuation of Peach Bottom Atomic Power Station (York County, PA) (Peach Bottom). During 2008,

Generation, PECO and the taxing authorities entered into an agreement that includes settlement of all outstanding real estate tax appeals. The agreement did not have a material impact on the respective results of operations, cash flows or financial positions for Generation, PECO or Exelon.

Generation has been involved in real estate tax appeals for the 2005, 2006 and 2007 tax years concerning the value of its Byron Generating Station (Ogle County, Illinois) for real estate tax purposes. During 2008, Generation and the taxing authorities entered into an agreement that includes settlement of all outstanding real estate tax appeals. The agreement did not have a material impact on the respective results of operations, cash flows or financial positions for Generation or Exelon.

The ultimate outcomes of such matters remain uncertain and could result in unfavorable or favorable impacts to the consolidated financial statements of Exelon, PECO and Generation. PECO and Generation believe that the payments that have been made for the 2006 and 2007 tax years and their reserve balances for exposures associated with real estate taxes as of December 31, 2008 reflect the probable expected outcome of the litigation and appeals proceedings in accordance with SFAS No. 5.

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. In the second quarter of 2008, Generation revised the period through which it estimates that claims will be presented from 2030 to 2050.

At December 31, 2008 and 2007, Generation had reserved approximately $52 million and $50 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2008, approximately $14 million of this amount related to 167 open claims presented to Generation, while the remaining $38 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050 based on actuarial assumptions and analysis, 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 2008, 2007 and 2006, the updates to this reserve, including the extension of future claims to be considered from 2030 to 2050, did not result in a material adjustment.

Flood Damage Claim. On September 12, 2006, a provider of specialty salvage services filed a lawsuit against Generation and one of its subsidiaries in the district court of Dallas County, Texas. The plaintiff alleged that operations at the Mountain Creek Reservoir and Dam on March 19, 2006 caused severe flooding and damage to the plaintiff's facilities and vehicle inventory located downstream of the reservoir and dam. The plaintiff also alleged supplemental damages for the future costs of relocating its facility. On May 29, 2008, the parties reached a confidential settlement agreement and on July 8, 2008, the lawsuit was dismissed. The settlement did not have a material impact on Exelon's and Generation's results of operations, cash flows, or financial positions.

Oil Spill Liability Trust Fund Claim. In December 2004, the two Salem nuclear generation units were taken offline due to an oil spill from a tanker in the Delaware River near the facilities. The units, which draw water from the river for cooling purposes, were taken offline for approximately two weeks to avoid intake of the spilled oil and for an additional two weeks relating to start up issues arising from the oil spill shutdown. The total shutdown period resulted in lost sales from the plant. Generation and PSEG subsequently filed a joint claim for losses and damages with the Oil Spill Liability Trust Fund. In December 2008, the Oil Spill Liability Trust Fund awarded $14 million to Exelon for its share of losses and damages. The award amount, received in January 2009, was recognized in operating revenues in Exelon's and Generation's Consolidated Statement of Operations in December 2008.

Uranium Supply Agreement Non-performance Claims. Generation enters into long-term supply agreements to procure uranium concentrates. In 2007, Generation initiated claims asserting non-performance by certain counterparties. As a result of this non-performance, Generation will be required to procure uranium concentrates at higher prices than originally anticipated. Generation has filed suit against two counterparties asserting breach of uranium supply agreement against one counterparty and breach of performance guarantee and fraudulent inducement against the other counterparty. On February 29, 2008, a settlement was reached with the one counterparty against whom Generation asserted breach of uranium supply agreement. Under the terms of the settlement, Generation has accepted uranium valued at $14 million from the counterparty, with no cash payment or other consideration due from Generation and recorded the gain as a reduction in fuel expense on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. On May 12, 2008, a settlement agreement was reached by Generation and the counterparty against whom Generation asserted breach of performance guarantee and fraudulent inducement. Under the terms of the settlement agreement, Generation accepted from the counterparty uranium valued at $24 million, a $15 million supplemental cash payment due to Generation on or before January 12, 2009, which was paid in September 2008, and a $2 million cash payment

received in May 2008 by Generation for the reimbursement of expenses. The total gain from the settlement of $41 million was recorded as a $39 million reduction in fuel expense and a $2 million reduction in operating and maintenance expenses on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. There were no other unresolved uranium supply matters as of December 31, 2008.

Coal Supply Agreement Matter. In September 2005, Generation entered into a Coal Supply Agreement (Agreement) with Guasare Coal International, N.V. (Guasare). The Agreement, as amended, provides for Guasare to supply approximately 390,000 metric tons of coal per year to Generation at prices fixed through December 31, 2009. By letter dated December 27, 2007, Guasare advised Generation that it was suspending shipments under the Agreement. On June 11, 2008: (1) Exelon International Commodities, LLC (a subsidiary of Generation) and Guasare entered into a new Coal Supply Agreement which provides for Guasare to supply approximately 200,000 metric tons of coal through December 31, 2008 to Exelon International Commodities, LLC at fixed prices; and (2) Generation and Guasare entered into a Settlement and Release Agreement which became effective on July 14, 2008 and released both parties from their respective rights and obligations under the original Agreement.

Pension Claim. 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 Federal District Court for the Northern District of Illinois. The complaint alleges that the Plan, which covers certain management employees of Exelon's subsidiaries, calculated lump sum distributions in a manner that does not comply with the Employee Retirement Income Security Act (ERISA). The plaintiff seeks compensatory relief from the Plan on behalf of participants who received lump sum distributions since 2001 and injunctive relief with respect to future lump sum distributions. On August 31, 2007, the District Court dismissed the lawsuit in its entirety. On December 21, 2007, the District Court amended its order, in part, to allow 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 January 16, 2008, the plaintiff filed a notice of appeal in the U.S. Court of Appeals for the Seventh Circuit of the District Court's dismissal of his claims. It is currently anticipated that the Seventh Circuit will hear argument on this appeal in 2009. In addition, on January 6, 2009, the plaintiff filed a complaint in the District Court challenging the Plan's denial of his administrative claim. The ultimate outcome of the pension claim is uncertain and may have a material adverse impact on Exelon's results of operations, cash flows or financial position.

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 United States 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 alleges 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 seek declaratory, equitable and monetary relief on behalf of the Savings Plan and participants, including alleged investment losses. On February 21, 2007, the district court granted the defendants' motion to strike the plaintiffs' claim for investment losses. On June 27, 2007, the district court granted the plaintiffs' motion for class certification. On June 28, 2007, the district court granted the defendants' motion to stay proceedings in this action pending the outcome of the appeal to the U.S. Seventh Circuit Court of Appeals in another case not involving Exelon. In that case, an appeal is pending before the Seventh Circuit from the June 20, 2007 decision of the U.S. District Court for the Western District of Wisconsin, which dismissed with prejudice substantially similar claims. Exelon is assessing the potential impact of the savings plan claim on its operations and financial results and condition.

Retiree Healthcare Benefits Grievance. In 2006, Local 15 of the International Brotherhood of Electrical Workers (IBEW Local 15) filed a demand for arbitration of a grievance challenging certain changes implemented in 2004 to the health care coverage provided to retirees who were members of IBEW Local 15 during their employment with Exelon, Generation and ComEd. Exelon then filed a lawsuit in the U.S. District Court for the Northern District of Illinois seeking a judicial determination that this grievance is not arbitrable as disputes regarding benefits provided to current retirees are not within the scope of the collective bargaining agreement. On December 3, 2007, the U.S. District Court ruled that under the terms of the parties' collective bargaining agreement, IBEW Local 15 could use the collective bargaining agreement's grievance and arbitration procedure to challenge these changes with respect to retirees named in the grievance. On September 8, 2008, the U.S. Court of Appeals for the Seventh Circuit affirmed the decision of the district court. Arbitration of this grievance is scheduled to commence on February 23, 2009. The ultimate outcome of the retiree healthcare benefits grievance is uncertain and may have a material adverse 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 effect on the Registrants' results of operations, cash flows or financial positions.

Reliability. On July 18, 2008, ComEd self-reported to Reliability*First* Corporation, the entity responsible for monitoring reliability in ComEd's region, that it failed to maintain vegetation clearance on a section of a transmission line, constituting a violation of a North American Electric Reliability Corporation (NERC) reliability standard. ComEd is subject to potential fines for a violation of NERC reliability standards. The ultimate outcome of this matter remains uncertain but ComEd does not believe it would result in a material adverse impact to ComEd's consolidated financial statements.

Fund Transfer Restrictions

Under applicable law, Exelon may borrow or receive any extension of credit or indemnity 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 stock. At December 31, 2008, such capital was $2.7 billion and amounted to about 31 times the liquidating value of the outstanding preferred stock 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 PECO Energy Capital, L.P. (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.

AmerGen Contingency Payment

In connection with the purchase of Unit No. 1 of the TMI facility by AmerGen in 2000, AmerGen entered into an agreement with the seller whereby the seller would receive additional consideration based upon future purchase power prices through 2009. Under the terms of the agreement, approximately $10 million and $11 million had been accrued at December 31, 2008 and 2007, respectively. The amount accrued as of December 31, 2008 was paid in January 2009. The amount accrued as of December 31, 2007 was paid to the former owners of the TMI facility in the first quarter of 2008. These payments represented contingent consideration for the original acquisition and have accordingly been reflected as an increase to the long-lived assets associated with the TMI facility, and are being depreciated over the remaining useful life of the facility.

Agreement Related to Sale of Accounts Receivable

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 PECO accounted for as a sale under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities—a Replacement of FASB Statement No. 125," (SFAS No. 140). PECO retains the servicing responsibility for the sold receivables and has recorded a servicing liability in accordance with FASB Statement No. 156, "Accounting for Servicing of Financial Assets, an amendment of FASB Statement No. 140" (SFAS No. 156). The agreement terminates on September 18, 2009 unless extended in accordance with its terms. As of December 31, 2008, PECO is in compliance with the requirements of the agreement. See Note 8—Fair Value of Financial Assets and Liabilities for additional information regarding the servicing liability.

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 for the years ended December 31, 2008, 2007 and 2006.

For the Year Ended December 31, 2008

Operating revenues [a]	
Wholesale	$ 6,394
Retail electric and gas	11,816 [b]
Other	649 [c]
Total operating revenues	$18,859

(a) Includes operating revenues from affiliates.
(b) Generation's retail electric and gas operating revenues consist solely of Exelon Energy Company, LLC.
(c) Includes amounts recorded related to the Illinois Settlement.

For the Year Ended December 31, 2007

Operating revenues [a]	
Wholesale	$ 6,550
Retail electric and gas	11,750 [b]
Other	616 [c]
Total operating revenues	$18,916

(a) Includes operating revenues from affiliates.
(b) Generation's retail electric and gas operating revenues consist solely of Exelon Energy Company, LLC.
(c) Includes amounts recorded related to the Illinois Settlement as well as income associated with the termination of Generation's PPA with State Line.

For the Year Ended December 31, 2006

Operating revenues [a]	
Wholesale	$ 3,627
Retail electric and gas	11,318 [b]
Other	710
Total operating revenues	$15,655

(a) Includes operating revenues from affiliates.
(b) Generation's retail electric and gas operating revenues consist solely of Exelon Energy Company, LLC.

For the Year Ended December 31, 2008

Depreciation, amortization and accretion	
Property, plant and equipment	$ 898
Regulatory assets [a]	736
Nuclear fuel [b]	448
Asset retirement obligation accretion [c]	226
Total depreciation, amortization and accretion	$2,308

(a) For PECO, reflects CTC amortization.
(b) Included in fuel expense on the Registrants' Consolidated Statements of Operations.
(c) Included in operating and maintenance expense on the Registrants' Consolidated Statements of Operations.

For the Year Ended December 31, 2007

Depreciation, amortization and accretion	
Property, plant and equipment	$ 856
Regulatory assets [a]	664
Nuclear fuel [b]	431
Asset retirement obligation accretion [c]	232
Total depreciation, amortization and accretion	$2,183

(a) For PECO, reflects CTC amortization.
(b) Included in fuel expense on the Registrants' Consolidated Statements of Operations.
(c) Included in operating and maintenance expense on the Registrants' Consolidated Statements of Operations.

For the Year Ended December 31, 2006

Depreciation, amortization and accretion	
Property, plant and equipment	$ 854
Regulatory assets [a]	605
Nuclear fuel [b]	411
Asset retirement obligation accretion [c]	235
Amortization of intangible assets	27
Total depreciation, amortization and accretion	$2,132

(a) For PECO, reflects CTC amortization.
(b) Included in fuel expense on the Registrants' Consolidated Statements of Operations.
(c) Included in operating and maintenance expense on the Registrants' Consolidated Statements of Operations.

For the Year Ended December 31, 2008

Taxes other than income	
Utility [a]	$507
Real estate [b]	127
Payroll	123
Other	21
Total taxes other than income	$778

(a) Municipal and state utility taxes are also recorded in revenues on the Registrants' Consolidated Statements of Operations.
(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, 2007

Taxes other than income	
Utility [(a)]	$527
Real estate [(b)]	139
Payroll	108
Other	23
Total taxes other than income	$797

(a) Municipal and state utility taxes are also recorded in revenues on the Registrants' Consolidated Statements of Operations.
(b) PECO reflected a $17 million reduction of a reserve related to the PURTA tax settlement, partially offset by current year property taxes.

For the Year Ended December 31, 2006

Taxes other than income	
Utility [(a)]	$484
Real estate	154
Payroll	106
Other [(b)]	27
Total taxes other than income	$771

(a) Municipal and state utility taxes are also recorded in revenues on the Registrants' Consolidated Statements of Operations.
(b) PECO reflected a reduction in tax accruals of $12 million following settlements related to prior year tax assessments.

For the Year Ended December 31, 2008

Loss in equity method investments	
Financing trusts of ComEd and PECO	$ (25)
NuStart Energy Development, LLC	(1)
Total loss in equity method investments	$ (26)

For the Year Ended December 31, 2007

Income (loss) in equity method investments	
Financing trusts of ComEd and PECO	$ (14)
TEG and TEP [(a)]	3
Synthetic fuel-producing facilities	(93)
NuStart Energy Development, LLC	(2)
Total income (loss) in equity method investments	$(106)

(a) On February 9, 2007, Generation sold its ownership interests in TEG and TEP. See Note 2–Acquisitions and Dispositions for additional information.

For the Year Ended December 31, 2006

Loss in equity method investments	
Financing trusts of ComEd and PECO	$ (19)
TEG and TEP	(7)
Synthetic fuel-producing facilities	(83)
NuStart Energy Development, LLC	(2)
Total loss in equity method investments	$(111)

For the Year Ended December 31, 2008

Other, net	
Investment income	$ 10
Decommissioning-related activities	
Net realized income on decommissioning trust funds—Regulated Units [a]	43
Net realized income on decommissioning trust funds—Unregulated Units [a]	16
Net unrealized losses on decommissioning trust funds—Regulated Units	(1,022)
Net unrealized losses on decommissioning trust funds—Unregulated Units	(324)
Regulatory offset to decommissioning trust fund-related activities [b]	777
Net direct financing lease income	24
Interest income related to uncertain income tax positions	31
Income related to the termination of a gas supply guarantee	13
Other	25
Total other, net	$ (407)

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.

(b) Includes the elimination of decommissioning trust fund-related activity for the Regulated Units, which are subject to regulatory accounting, including the elimination of net realized income, net unrealized losses and related income taxes. See Notes 8—Fair Value of Financial Assets and Liabilities and 12—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

For the Year Ended December 31, 2007

Other, net	
Investment income	$ 10
Gain on disposition of assets and investments, net	23
Decommissioning-related activities	
Net realized income on decommissioning trust funds—Regulated Units [a]	387
Net realized income on decommissioning trust funds—Unregulated Units [a]	120
Other-than-temporary impairment of decommissioning trust funds—Regulated Units [b]	(83)
Other-than-temporary impairment of decommissioning trust funds—Unregulated Units [b]	(9)
Regulatory offset to decommissioning trust fund-related activities [c]	(300)
Net direct financing lease income	24
Recovery of tax credits related to Exelon's investments in synthetic fuel-producing facilities	178
Interest income related to settlement of PJM billing dispute	5
Interest income related to uncertain tax positions	61
Interest income related to PURTA tax appeal [d]	17
Other	27
Total other, net	$ 460

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.

(b) Includes net unrealized losses of the trust funds.

(c) Includes the elimination of decommissioning trust fund-related activity for the Regulated Units, which are subject to regulatory accounting, including the elimination of net realized income, other-than-temporary impairments and related income taxes. See Notes 8—Fair Value of Financial Assets and Liabilities and 12—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(d) On March 27, 2007, PECO prevailed in a Pennsylvania Supreme Court case in which PECO had contested the assessment of Pennsylvania Public Utility Realty Tax Act (PURTA) taxes applicable to 1997. As a result, during the third quarter of 2007, PECO recognized approximately $17 million of interest income associated with this matter.

For the Year Ended December 31, 2006

Other, net	
Investment income	$ 8
Regulatory recovery of prior loss on extinguishment of long-term debt [a]	87
Gain on disposition of assets, net	3
Decommissioning-related activities	
Net realized income on decommissioning trust funds – Regulated Units [b]	150
Net realized income on decommissioning trust funds – Unregulated Units [b]	39
Other-than-temporary impairment of decommissioning trust funds – Regulated Units [c]	(30)
Other-than-temporary impairment of decommissioning trust funds – Unregulated Units [c]	(2)
Regulatory offset to decommissioning trust fund-related activities [d]	(122)
Impairment of investments and other assets	(2)
Net direct financing lease income	23
Recovery of tax credits related to Exelon's investments in synthetic fuel-producing facilities	73
Interest income associated with investment tax credit and research and development credit refunds	21
Other	18
Total other, net	$ 266

(a) Recovery of these costs was granted in the July 26, 2006 ICC rate order.
(b) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(c) Includes net unrealized losses of the trust funds
(d) Includes the elimination of decommissioning trust fund-related activity for the Regulated Units, which are subject to regulatory accounting, including the elimination of net realized income, other-than-temporary impairments and related income taxes. See Notes 8—Fair Value of Financial Assets and Liabilities and 12—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

Supplemental Cash Flow Information

The following tables provide additional information regarding Exelon's Consolidated Statements of Cash Flows for the years ended December 31, 2008, 2007 and 2006.

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
Equity in losses of unconsolidated affiliates	26
Provision for uncollectible accounts	247
Stock-based compensation costs	67
Net realized losses on sales of investments of nuclear decommissioning trust funds	183
Net unrealized losses on nuclear decommissioning trust funds	324
Other decommissioning-related activities	75
Amortization of energy related options	5
Amortization of regulatory asset related to debt costs	25
Amortization of the regulatory liability related to the PURTA tax settlement [a]	(36)
Net impact of the 2007 distribution rate case order [b]	22
Reduction of guarantees [f]	(55)
Other	36
Total other non-cash operating activities	$1,233
Changes in other assets and liabilities	
Deferred/over-recovered energy costs	$ 32
Other current assets	(74)
Other noncurrent assets and liabilities	(411)
Total change in other assets and liabilities	$ (453)

(a) On March 27, 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. PECO began amortizing this regulatory liability and refunding the amount to customers in January 2008.
(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 totaling approximately $13 million associated with reversing previously incurred expenses deemed recoverable in future rates. See Note 3—Regulatory Issues for more information.
(c) Relates primarily to the purchase of energy-related options and prepaid assets.
(d) Relates primarily to the purchase of long-term fuel options.
(e) Relates primarily to prepaid utility taxes.
(f) Includes reversal of Sithe guarantee of $38 million and Distrigas guarantee of $13 million.

Non-cash investing and financing activities	
Change in asset retirement cost	$ 128
Capital expenditures not paid	23
Capitalized employee incentives	4
Purchase accounting adjustments	10

For the Year Ended December 31, 2007

Cash paid during the year	
Interest (net of amount capitalized)	$ 879
Income taxes (net of refunds)	1,298
Other non-cash operating activities	
Pension and non-pension postretirement benefits costs	$ 320
Provision for uncollectible accounts	132
Equity in losses (gains) of unconsolidated affiliates	106
Other decommissioning-related activities	146
Amortization of energy related options	133
Net realized gains on nuclear decommissioning trust funds	(291)
Gain on sale of investments, net	(18)
Loss on execution of sub-lease	72
Other	64
Total other non-cash operating activities	$ 664
Changes in other assets and liabilities	
Deferred/over-recovered energy costs	$ (91)
Other current assets	(131) [a]
Other noncurrent assets and liabilities	(42) [b]
Total change in other assets and liabilities	$ (264)

(a) Relates primarily to the purchase of energy-related options.
(b) Relates primarily to the purchase of long-term fuel options and interest accrued on spent nuclear fuel obligations.

Non-cash investing and financing activities	
Change in asset retirement cost	$ 60
Declaration of dividend not paid as of December 31, 2007	331
Purchase accounting adjustments	11
Resolution of certain tax matters [a]	69
ComEd Transitional Funding Trust [b] [c]	25
Capital expenditures not paid	29

(a) Includes amounts recorded to goodwill resulting from the resolution of certain tax matters and the impact of adopting FIN 48 for uncertain tax positions of ComEd that existed at the PECO / Unicom merger, in accordance with EITF 93-7.
(b) Amount includes $17 million previously reflected in prepaid interest. This amount did not impact ComEd's Consolidated Statement of Operations or ComEd's Consolidated Statement of Cash Flows.
(c) ComEd applied $8 million of previously prepaid balances against the long-term debt to ComEd Transitional Funding Trust.

For the Year Ended December 31, 2006

Cash paid during the year	
Interest (net of amount capitalized)	$ 664
Income taxes (net of refunds)	1,044
Impairment charges	
Impairment of goodwill	$ 776
Impairment of intangible assets [(a)]	115
Other	3
Total impairment charges	$ 894
Other non-cash operating activities	
Pension and non-pension postretirement benefits costs	$ 258
Provision for uncollectible accounts	94
Equity in losses of unconsolidated affiliates	111
Other decommissioning-related activities	(131)
Amortization of energy related options	107
Amortization of deferred revenue	(86)
Spent nuclear fuel interest expense	44
Non-cash accounts receivable activity	(63)
Write-off Merger-related capitalized costs [(b)]	46
2006 ICC rate orders [(c)]	(288)
Other	105
Total other non-cash operating activities	$ 197
Changes in other assets and liabilities	
Deferred/over-recovered energy costs	$ 45
Other current assets	(80) [(d)]
Other noncurrent assets and liabilities	(201) [(e)]
Total change in other assets and liabilities	$ (236)

(a) Exelon recorded an impairment charge associated with the full write-off of an intangible asset related to its investment in synthetic fuel-producing facilities. See Note 11—Income Taxes.
(b) Represents the Merger-related capitalized costs paid prior to 2006.
(c) See Note 3—Regulatory Issues.
(d) Relates primarily to the purchase of energy-related options.
(e) Relates primarily to the purchase of long-term fuel options.

Non-cash investing and financing activities	
Change in asset retirement cost	$393
Declaration of dividend not paid as of December 31, 2006	295
Purchase accounting adjustments	25
Resolution of certain tax matters and PECO/Unicom merger severance adjustment	5

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of Exelon as of December 31, 2008 and 2007.

December 31, 2008

Investments	
Equity method investments:	
Financing trusts [(a)]	$ 45
Keystone Fuels, LLC	8
Conemaugh Fuels, LLC	14
NuStart Energy Development, LLC	2
Total equity method investments	69
Other investments:	
Net investment in direct financing leases	577
Employee benefit trusts and investments [(b)]	69
Total investments	$715

(a) Includes investments in financing trusts which were not consolidated within the financial statements of Exelon at December 31, 2008 pursuant to the provisions of FIN 46-R. See Note 1—Significant Accounting Policies for additional discussion of the effects of FIN 46-R.

(b) The Registrants' investments in these marketable securities are recorded at fair market value.

December 31, 2007

Investments	
Equity method investments:	
Financing trusts [(a)]	$ 63
Keystone Fuels, LLC	7
Conemaugh Fuels, LLC	6
NuStart Energy Development, LLC	1
Total equity method investments	77
Other investments:	
Net investment in direct financing leases	553
Employee benefit trusts and investments [(b)]	100
Other	1
Total investments	$731

(a) Includes investments in financing trusts which were not consolidated within the financial statements of Exelon at December 31, 2007 pursuant to the provisions of FIN 46-R. See Note 1—Significant Accounting Policies for additional discussion of the effects of FIN 46-R.

(b) The Registrants' investments in these marketable securities are recorded at fair market value.

Like-Kind Exchange Transaction (Exelon). 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. Under the terms of the lease agreements, UII received a prepayment of $1.2 billion in the fourth quarter of 2000, which reduced the investment in the leases. The remaining payments are payable at the end of the thirty-year leases and there are no minimum scheduled lease payments to be received over the next five years. The components of the net investment in the direct financing leases were as follows:

	December 31,	
	2008	2007
Total minimum lease payments	$1,492	$1,492
Less: unearned income	915	939
Net investment in direct financing leases	$ 577	$ 553

The following tables provide additional information about liabilities of Exelon at December 31, 2008 and 2007.

December 31, 2008

Accrued expenses	
Compensation-related accruals [(a)]	$ 464
Taxes accrued	439
Interest accrued	155
Severance accrued	17
Other accrued expenses	76
Total accrued expenses	$1,151

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.

December 31, 2007

Accrued expenses	
Compensation-related accruals [(a)]	$ 437
Taxes accrued	547
Interest accrued	137
Severance accrued	26
Other accrued expenses	93
Total accrued expenses	$1,240

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.

The following tables provide information regarding counterparty margin deposit accounts and option premiums as of December 31, 2008 and 2007.

December 31, 2008

Other current assets	
Option premiums	$308
Other current liabilities	
Option premiums	267

December 31, 2007

Other current assets	
Option premiums	$189
Other current liabilities	
Dividends payable	331
Option premiums	163

The following tables provide additional information about accumulated other comprehensive income (loss) recorded (after tax) within Exelon's Consolidated Balance Sheets as of December 31, 2008 and 2007.

December 31, 2008

Accumulated other comprehensive income (loss)	
Minimum pension liability	$ (224)
Adjustment to initially apply SFAS No. 158	(1,268)
Net unrealized gain on cash-flow hedges	564
Pension and non-pension postretirement benefit plans	(1,317)
Unrealized loss on marketable securities	(6)
Total accumulated other comprehensive income (loss)	$(2,251)

December 31, 2007	
Accumulated other comprehensive income (loss)	
Minimum pension liability	$ (224)
Adjustment to initially apply SFAS No. 158	(1,268)
Net unrealized (loss) gain on cash-flow hedges	(292)
Pension and non-pension postretirement benefit plans	87
Unrealized gain on marketable securities	163
Total accumulated other comprehensive income (loss)	$(1,534)

The following tables provide information about Exelon's regulatory assets and liabilities as of December 31, 2008 and 2007.

December 31, 2008	
Regulatory assets	
Competitive transition charge	$1,666
Pension and other postretirement benefits	2,855
Deferred income taxes	826
Debt costs	169
Severance	116
Conditional asset retirement obligations	128
MGP remediation costs	121
Rate case costs	15
RTO start-up costs	14
Other	30
Noncurrent regulatory assets	5,940
Under-recovered energy costs current asset	58
Total regulatory assets	$5,998

December 31, 2008	
Regulatory liabilities	
Nuclear decommissioning	$1,336
Removal costs	1,145
Refund of PURTA taxes [(a)]	2
Deferred taxes	30
Energy efficiency and demand response programs	7
Noncurrent regulatory liabilities	2,520
Over-recovered energy costs current liability	13
Total regulatory liabilities	$2,533

(a) On March 27, 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. PECO began amortizing this regulatory liability and refunding the amount to customers in January 2008.

December 31, 2007	
Regulatory assets	
Competitive transition charge	$2,363
Pension and other postretirement benefits	1,389
Deferred income taxes	812
Debt costs	177
Severance	137
Conditional asset retirement obligations	115
MGP remediation costs	96
Rate case costs	5
Procurement case costs	3
Other	36
Noncurrent regulatory assets	5,133
Under-recovered energy costs current asset	101
Total regulatory assets	$5,234

December 31, 2007	
Regulatory liabilities	
Nuclear decommissioning	$2,117
Removal costs	1,099
Refund of PURTA taxes [(a)]	38
Deferred taxes	47
Noncurrent regulatory liabilities	3,301
Over-recovered energy costs current liability	16
Total regulatory liabilities	$3,317

(a) On March 27, 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.

Competitive Transition Charges. These charges represent PECO's stranded costs that the PAPUC determined would be recoverable through regulated rates. These costs are related to the deregulation of the generation portion of the electric utility business in Pennsylvania. The CTCs include intangible transition property sold to PETT, an unconsolidated subsidiary of PECO, in connection with the securitization of PECO's stranded cost recovery. These charges are being amortized through December 31, 2010 with a return on the unamortized balance of 10.75%.

Pension and other postretirement benefits. As of December 31, 2008, $2,829 million represents regulatory assets related to the recognition of the underfunded status of Exelon's defined benefit postretirement plans as a liability on its balance sheet in accordance with SFAS No. 158. 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 SFAS No. 87 and SFAS No. 106. Exelon believes it is probable that these items will be recovered through rates by ComEd and PECO in future periods. See Note 14–Retirement Benefits for additional detail. In addition, $26 million is the result of PECO transitioning to SFAS No. 106 in 1993, which is recoverable in rates through 2012.

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 by unregulated entities. Regulatory assets and liabilities associated with deferred income taxes, recorded in compliance with SFAS No. 71 and SFAS No. 109, 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 rates. See Note 11—Income Taxes for additional information.

Debt Costs. The reacquired debt costs represent premiums paid for the early extinguishment and refinancing of long-term debt, which is amortized over the life of the new debt issued to finance the debt redemption. Interest-rate swap settlements are deferred and amortized over the period that the related debt is outstanding.

Severance costs. These costs represent previously incurred severance costs that ComEd was granted recovery of in the December 20, 2006 ICC rehearing order. Recovery is over 7.5 years.

Conditional asset retirement obligations. These costs represent future removal costs associated with retirement obligations which will be collected over the remaining lives of the underlying assets. 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 represent estimated MGP-related environmental remediation costs which are recoverable through rates as prescribed in the 2008 joint settlement of the gas distribution rate case. The period of recovery for both ComEd and PECO will depend on the timing of the actual expenditures.

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. Pursuant to the joint settlement of the 2008 gas distribution rate case, PECO is allowed recovery of rate case costs over two years.

Procurement case costs. Recovery of these items was granted to ComEd in the July 26, 2006 ICC rate order. Recovery is over three years.

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 received from customers to cover the future removal of property, plant and equipment which reduces rate base for ratemaking purposes.

Financial swap with Generation. To fulfill a requirement of the Illinois Settlement, ComEd entered into a five-year financial swap contract with Generation. 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 recorded a regulatory asset related to its mark-to-market derivative liability position as of December 31, 2008 and a regulatory liability related to its mark-to-market derivative asset position as of December 31, 2007. The basis for the mark-to-market derivative position is based on the difference between the 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. See Note 3—Regulatory Issues for additional information.

Deferred (over-recovered) energy costs current asset (liability). Starting in 2007, the ComEd costs are recoverable (refundable) under ComEd's ICC and/or FERC-approved rates. ComEd's deferred energy 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's deferred energy costs earn a rate of return. A return on over-recovered energy costs is paid to customers in addition to the over-recovered energy costs.

The regulatory assets related to pension and other postretirement benefit plans, deferred income taxes, non-pension postretirement benefits, MGP remediation, severance, Procurement Case and Rate Case are not earning a rate of return. Recovery of the regulatory assets for conditional asset retirement obligations, debt costs, recoverable transition costs and deferred energy costs are earning a rate of return.

20. Segment Information

Exelon has three operating segments: Generation, ComEd and PECO. Exelon evaluates the performance of its business segments based on net income. Generation, ComEd and PECO each operate in a single business segment; as such, no separate segment information is provided for these Registrants. An analysis and reconciliation of Exelon's operating segment information to the respective information in the consolidated financial statements are as follows:

	Generation	ComEd	PECO	Other	Intersegment Eliminations	Consolidated
Total revenues [a]:						
2008	$10,754	$ 6,136	$5,567	$ 697	$ (4,295)	$18,859
2007	10,749	6,104	5,613	741	(4,291)	18,916
2006	9,143	6,101	5,168	807	(5,564)	15,655
Intersegment revenues:						
2008	$ 3,586	$ 4	$ 10	$ 695	$ (4,295)	$ —
2007	3,538	2	11	740	(4,291)	—
2006	4,742	7	8	807	(5,564)	—
Depreciation and amortization:						
2008	$ 274	$ 464	$ 854	$ 42	$ —	$ 1,634
2007	267	440	773	40	—	1,520
2006	279	430	710	68	—	1,487
Operating expenses [a]:						
2008	$ 6,760	$ 5,469	$4,868	$ 758	$ (4,295)	$13,560
2007	7,357	5,592	4,666	924	(4,291)	14,248
2006	6,747	5,546 [b]	4,302	1,103	(5,564)	12,134 [b]
Interest expense, net:						
2008	$ 136	$ 348	$ 226	$ 132	$ (10)	$ 832
2007	161	318	248	124	(1)	850
2006	159	308	266	152	(5)	880
Income taxes:						
2008	$ 1,130	$ 128	$ 150	$ (91)	$ —	$ 1,317
2007	1,362	80	230	(226)	—	1,446
2006	866	445	180	(285)	—	1,206
Income (loss) from continuing operations:						
2008	$ 2,258	$ 201	$ 325	$ (67)	$ —	$ 2,717
2007	2,025	165	507	29	—	2,726
2006	1,403	(112) [b]	441	(142)	—	1,590 [b]
Income (loss) from discontinued operations:						
2008	$ 20	$ —	$ —	$ —	$ —	$ 20
2007	4	—	—	6	—	10
2006	4	—	—	(2)	—	2
Net income (loss):						
2008	$ 2,278	$ 201	$ 325	$ (67)	$ —	$ 2,737
2007	2,029	165	507	35	—	2,736
2006	1,407	(112) [b]	441	(144)	—	1,592 [b]
Capital expenditures:						
2008	$ 1,699	$ 953	$ 392	$ 73	$ —	$ 3,117
2007	1,269	1,040	339	26	—	2,674
2006	1,109	911	345	53	—	2,418
Total assets [c]:						
2008	$20,355	$19,237	$9,169	$16,593	$(17,537)	$47,817
2007	18,521	19,376	9,810	14,621	(16,967)	45,361

(a) Utility taxes of $236 million, $258 million and $241 million are included in revenues and expenses for 2008, 2007 and 2006, respectively, for ComEd. Utility taxes of $271 million, $269 million and $244 million are included in revenues and expenses for 2008, 2007 and 2006, respectively, for PECO.
(b) Includes goodwill impairment charge of $ 776 million in 2006.
(c) Exelon and Generation retrospectively reclassified certain assets and liabilities in accordance with FIN 39 as amended by FSP FIN 39-1.

21. Related Party Transactions

The financial statements of Exelon include related-party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2008	2007	2006
Operating revenues from affiliates			
ComEd Transitional Funding Trust	$ 3	$ 3	$ 3
PETT	5	6	7
Other	—	1	—
Total operating revenues from affiliates	$ 8	$ 10	$ 10
Fuel purchases from related parties			
Keystone Fuels, LLC	$ 73	$ 46	$ 49
Conemaugh Fuels, LLC	54	46	47
Total fuel purchases from related parties	$127	$ 92	$ 96
Charitable contribution to Exelon Foundation [(a)]	$—	$ 50	$ —
Interest expense to affiliates, net			
ComEd Transitional Funding Trust	$ 6	$ 27	$ 47
ComEd Financing II	2	13	13
ComEd Financing III	13	13	13
PETT	101	139	180
PECO Trust III	6	6	6
PECO Trust IV	6	6	6
Other	(1)	(1)	(1)
Total interest expense to affiliates, net	$133	$ 203	$ 264
Equity in earnings (losses) of unconsolidated affiliates			
ComEd Funding LLC	$ (8)	$ (7)	$ (10)
PETT	(16)	(7)	(9)
TEG and TEP [(d)]	—	3	(7)
Investment in synthetic fuel-producing facilities	—	(93)	(83)
Other	(2)	(2)	(2)
Total equity in losses of unconsolidated affiliates	$ (26)	$(106)	$(111)

	December 31, 2008	December 31, 2007
Receivables from affiliates (current)		
ComEd Transitional Funding Trust	$ —	$ 15
Investments in affiliates		
ComEd Funding LLC [b]	—	(10)
ComEd Financing II [c]	—	10
ComEd Financing III	6	6
PETT	30	47
PECO Energy Capital Corporation	4	4
PECO Trust IV	5	6
Total investment in affiliates	$ 45	$ 63
Payables to affiliates (current)		
ComEd Financing II	—	6
ComEd Financing III	4	4
PECO Trust III	1	1
Total payables to affiliates (current)	$ 5	$ 11
Long-term debt to ComEd Transitional Funding Trust, PETT and other financing trusts (including due within one year)		
ComEd Transitional Funding Trust	$ —	$ 274
ComEd Financing II [c]	—	155
ComEd Financing III	206	206
PETT	1,124	1,732
PECO Trust III	81	81
PECO Trust IV	103	103
Total long-term debt due to financing trusts	$1,514	$2,551

(a) Exelon Foundation is a nonconsolidated not-for-profit Illinois corporation. The Exelon Foundation was established in the fourth quarter of 2007 to serve educational and environmental philanthropic purposes and does not serve a direct business or political purpose of Exelon.

(b) In the fourth quarter of 2008, ComEd paid off its long-term debt obligations to the ComEd Transitional Funding Trust and received its current receivable from the ComEd Transitional Funding Trust. Subsequently in 2008, ComEd Funding LLC liquidated its investment in the ComEd Transitional Funding Trust and ComEd liquidated its investment in ComEd Funding LLC.

(c) ComEd Financing II was liquidated and dissolved upon repayment of the debt in 2008.

(d) Generation's ownership interest in Termoelectrica del Golfo (TEG) and Termoelectrica Penoles (TEP) was sold in 2007.

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 (Loss)	
	2008	2007	2008	2007	2008	2007
Quarter ended:						
March 31	$4,517	$4,829	$1,123	$1,191	$581	$691
June 30	4,622	4,501	1,430	1,231	748	702
September 30	5,228	5,032	1,413	1,351	700	780
December 31	4,493	4,554	1,333	896	707	562

	Average Basic Shares Outstanding (in millions)		Net Income (Loss) per Basic Share	
	2008	2007	2008	2007
Quarter ended:				
March 31	659	672	$0.88	$1.02
June 30	657	675	1.14	1.04
September 30	658	673	1.06	1.16
December 31	658	661	1.07	0.85

	Average Diluted Shares Outstanding (in millions)		Net Income (Loss) per Diluted Share	
	2008	2007	2008	2007
Quarter ended:				
March 31	664	677	$0.88	$1.02
June 30	662	680	1.13	1.03
September 30	662	678	1.06	1.15
December 31	661	666	1.07	0.84

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

	2008				2007			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$65.55	$91.64	$90.92	$86.52	$86.83	$82.60	$79.38	$72.31
Low price	45.00	61.16	82.22	73.04	73.76	64.73	68.67	58.74
Close	55.61	62.62	89.96	81.27	81.64	75.36	72.60	68.71
Dividends	0.525	0.500	0.500	0.500	0.440	0.440	0.440	0.440

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