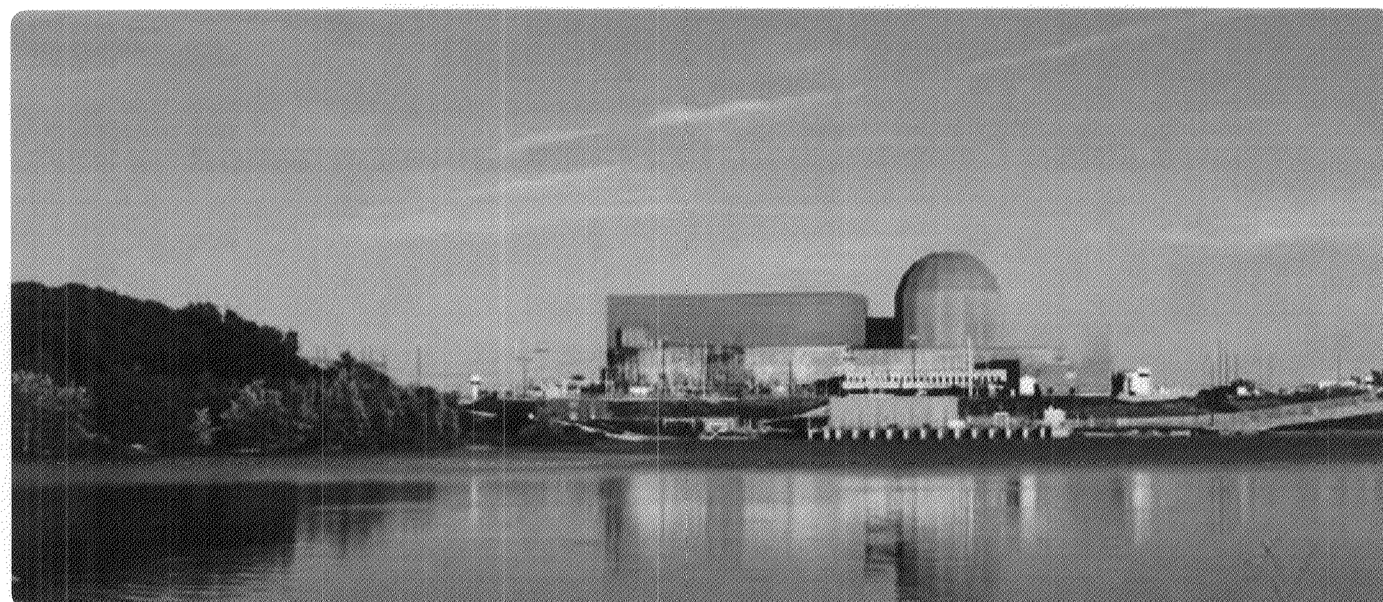
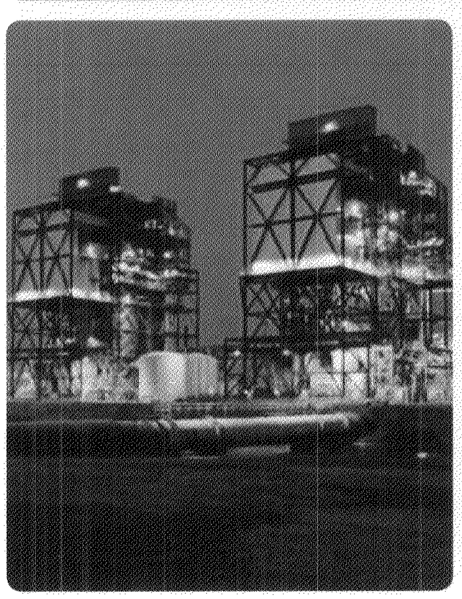
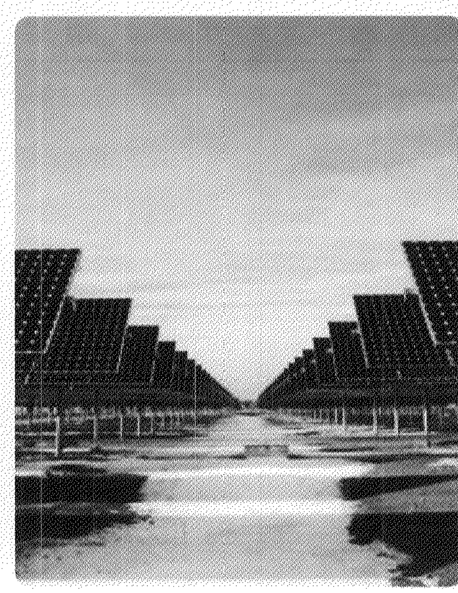
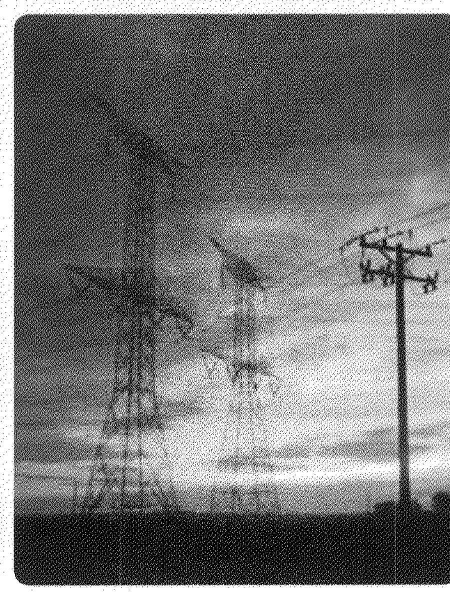
Exelon











# Exelon Corporation 2011 Financial Information

# Exelon Corporate 2011 Financial Information

## CORPORATE PROFILE

Exelon Corporation is one of the nation's largest electric utilities with more than $18 billion in annual revenues. The company has one of the industry's largest portfolios of electricity generation capacity, with a nationwide reach and strong positions in the Midwest and Mid-Atlantic. Exelon distributes electricity to approximately 5.4 million customers in northern Illinois and southeastern Pennsylvania and natural gas to approximately 494,000 customers in the Philadelphia area. Exelon is headquartered in Chicago and trades on the NYSE under the ticker EXC.

## INVESTOR AND GENERAL INFORMATION

**Corporate Headquarters**
Exelon Corporation
P.O. Box 805379
Chicago, IL 60680-5379

**Transfer Agent**
Wells Fargo
800.626.8729

**Employee Stock Purchase Plan**
877.582.5113

**Employee Stock Options**
888.609.3534

**Investor Relations Voice Mailbox**
312.394.2345

**Shareholder Services Voice Mailbox**
312.394.8811

**Independent Public Accountants**
PricewaterhouseCoopers LLP

**Website**
www.exeloncorp.com

**Stock Ticker**
EXC

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

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

The company had approximately 125,000 holders of record of its common stock as of December 31, 2011.

The 2011 Form 10-K Annual Report to the Securities and Exchange Commission was filed on February 9, 2012. To obtain a copy without charge, write to Bruce G. Wilson, Senior Vice President, Deputy General Counsel and Corporate Secretary, Exelon Corporation, Post Office Box 805379, Chicago, Illinois 60680-5379.

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

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## GLOSSARY OF TERMS AND ABBREVIATIONS

**Exelon Corporation and Related Entities**

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

**Other Terms and Abbreviations**

| | |
|---|---|
| *1998 restructuring settlement* | PECO's 1998 settlement of its restructuring case mandated by the Competition Act |
| *Act 129* | Pennsylvania Act 129 of 2008 |
| *AEC* | Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source |
| *AEPS Act* | Pennsylvania Alternative Energy Portfolio Standards Act of 2004 |
| *AFUDC* | Allowance for Funds Used During Construction |
| *ALJ* | Administrative Law Judge |
| *AMI* | Advanced Metering Infrastructure |
| *ARC* | Asset Retirement Cost |
| *ARO* | Asset Retirement Obligation |
| *ARP* | Title IV Acid Rain Program |
| *ARRA of 2009* | American Recovery and Reinvestment Act of 2009 |
| *Block contracts* | Forward Purchase Energy Block Contracts |
| *CAIR* | Clean Air Interstate Rule |
| *CAISO* | California ISO |
| *CAMR* | Federal Clean Air Mercury Rule |
| *CERCLA* | Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended |
| *CFL* | Compact Fluorescent Light |
| *Clean Air Act* | Clean Air Act of 1963, as amended |
| *Clean Water Act* | Federal Water Pollution Control Amendments of 1972, as amended |
| *Competition Act* | Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996 |
| *Constellation* | Constellation Energy Group, Inc. |
| *CPI* | Consumer Price Index |
| *CSAPR* | Cross-State Air Pollution Rule |
| *CTC* | Competitive Transition Charge |
| *DOE* | United States Department of Energy |
| *DOJ* | United States Department of Justice |
| *DSP Program* | Default Service Provider Program |
| *EE&C* | Energy Efficiency and Conservation/Demand Response |
| *EGS* | Electric Generation Supplier |
| *EIMA* | Illinois Senate Bill 1652 and Illinois House Bill 3036 |
| *EPA* | United States Environmental Protection Agency |
| *ERCOT* | Electric Reliability Council of Texas |
| *ERISA* | Employee Retirement Income Security Act of 1974, as amended |

**Other Terms and Abbreviations**

| | |
|---|---|
| *EROA* | Expected Rate of Return on Assets |
| *ESPP* | Employee Stock Purchase Plan |
| *FASB* | Financial Accounting Standards Board |
| *FERC* | Federal Energy Regulatory Commission |
| *FTC* | Federal Trade Commission |
| *GAAP* | Generally Accepted Accounting Principles in the United States |
| *GHG* | Greenhouse Gas |
| *GRT* | Gross Receipts Tax |
| *GSA* | Generation Supply Adjustment |
| *GWh* | Gigawatt hour |
| *HAP* | Hazardous air pollutants |
| *Health Care Reform Acts* | Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010 |
| *IBEW* | International Brotherhood of Electrical Workers |
| *ICC* | Illinois Commerce Commission |
| *ICE* | Intercontinental Exchange |
| *IFRS* | International Financial Reporting Standards |
| *Illinois Act* | Illinois Electric Service Customer Choice and Rate Relief Law of 1997 |
| *Illinois EPA* | Illinois Environmental Protection Agency |
| *Illinois Settlement Legislation* | Legislation enacted in 2007 affecting electric utilities in Illinois |
| *IPA* | Illinois Power Agency |
| *IRC* | Internal Revenue Code |
| *IRS* | Internal Revenue Service |
| *ISO* | Independent System Operator |
| *ISO-NE* | ISO New England Inc. |
| *kV* | Kilovolt |
| *kW* | Kilowatt |
| *kWh* | Kilowatt-hour |
| *LIBOR* | London Interbank Offered Rate |
| *LILO* | Lease-In, Lease-Out |
| *LLRW* | Low-Level Radioactive Waste |
| *LTIP* | Long-Term Incentive Plan |
| *MGP* | Manufactured Gas Plant |
| *MISO* | Midwest Independent Transmission System Operator, Inc. |
| *Moody's* | Moody's Investor Service |
| *mmcf* | Million Cubic Feet |
| *MRV* | Market-Related Value |
| *MW* | Megawatt |
| *MWh* | Megawatt hour |
| *NAAQS* | National Ambient Air Quality Standards |
| *NAV* | Net Asset Value |
| *NDT* | Nuclear Decommissioning Trust |
| *NEIL* | Nuclear Electric Insurance Limited |
| *NERC* | North American Electric Reliability Corporation |
| *NJDEP* | New Jersey Department of Environmental Protection |
| *Non-Regulatory Agreements Units* | Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting |
| *NOV* | Notice of Violation |
| *NPDES* | National Pollutant Discharge Elimination System |
| *NRC* | Nuclear Regulatory Commission |
| *NWPA* | Nuclear Waste Policy Act of 1982 |
| *NYMEX* | New York Mercantile Exchange |
| *OCI* | Other Comprehensive Income |
| *OPEB* | Other Postretirement Employee Benefits |
| *PA DEP* | Pennsylvania Department of Environmental Protection |

**Other Terms and Abbreviations**

| | |
|---|---|
| *PAPUC* | Pennsylvania Public Utility Commission |
| *PGC* | Purchased Gas Cost Clause |
| *PJM* | PJM Interconnection, LLC |
| *POLR* | Provider of Last Resort |
| *POR* | Purchase of Receivables |
| *PPA* | Power Purchase Agreement |
| *PCCA* | Pennsylvania Climate Change Act |
| *PRP* | Potentially Responsible Parties |
| *Price-Anderson Act* | Price-Anderson Nuclear Industries Indemnity Act of 1957 |
| *PSEG* | Public Service Enterprise Group Incorporated |
| *PURTA* | Pennsylvania Public Realty Tax Act |
| *PV* | Photovoltaic |
| *RCRA* | Resource Conservation and Recovery Act of 1976, as amended |
| *REC* | Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source |
| *Regulatory Agreement Units* | Nuclear generating units whose decommissioning-related activities are subject to contractual elimination under regulatory accounting |
| *RES* | Retail Electric Suppliers |
| *RFP* | Request for Proposal |
| *Rider* | Reconcilable Surcharge Recovery Mechanism |
| *RPM* | PJM Reliability Pricing Model |
| *RPS* | Renewable Energy Portfolio Standards |
| *RGGI* | Regional Greenhouse Gas Initiative |
| *RMC* | Risk Management Committee |
| *RTEP* | Regional Transmission Expansion Plan |
| *RTO* | Regional Transmission Organization |
| *S&P* | Standard & Poor's Ratings Services |
| *SEC* | United States Securities and Exchange Commission |
| *SERP* | Supplemental Employee Retirement Plan |
| *SFC* | Supplier Forward Contract |
| *SGIG* | Smart Grid Investment Grant |
| *SILO* | Sale-In, Lease-Out |
| *SMP* | Smart Meter Program |
| *SNF* | Spent Nuclear Fuel |
| *SSCM* | Simplified Service Cost Method |
| *Tax Relief Act of 2010* | Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 |
| *TEG* | Termoelectrica del Golfo |
| *TEP* | Termoelectrica Penoles |
| *Toxics Rule* | U.S. EPA Mercury and Air Toxics Rule |
| *VIE* | Variable Interest Entity |

## FILING FORMAT

The information included within this Financial Information Supplement has been taken from Exelon's Form 10-K annual report for the year ended December 31, 2011. That annual report was filed with the SEC on February 9, 2012 and can be viewed and retrieved through the SEC's website at *www.sec.gov* or our website at *www.exeloncorp.com*. We encourage you to consider the entire Form 10-K annual report, which contains more information about us and our subsidiaries than is presented in this Financial Information Supplement.

## FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this Financial Information Supplement are forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon include those factors discussed herein or in Exelon's 2011 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 2011 Form 10-K is available on Exelon's website at *www.exeloncorp.com* and will be made available, without charge, in print to any shareholder who requests such documents from Bruce G. Wilson, Senior Vice President, Deputy General Counsel, and Corporate Secretary, Exelon Corporation, P.O. Box 805398, Chicago, Illinois 60680-5398.

## GENERAL DESCRIPTION OF OUR BUSINESS

### General

Exelon, incorporated in Pennsylvania in February 1999, is a utility services holding company engaged, through its principal subsidiaries, Generation, in the energy generation business, and ComEd and PECO, in the energy delivery businesses discussed below. Exelon's principal executive offices are located at 10 South Dearborn Street, Chicago, Illinois 60603, and its telephone number is 312-394-7398.

### Generation

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

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

### ComEd

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

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

### PECO

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

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

### Operating Segments

See Note 20 of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's operating segments.

### Proposed Merger with Constellation Energy Group, Inc.

On April 28, 2011, Exelon and Constellation announced that they signed an agreement and plan of merger to combine the two companies in a stock-for-stock transaction. Under the merger agreement, Constellation's shareholders will receive 0.930 shares of Exelon common stock in exchange for each share of Constellation common stock. Constellation is a leading competitive supplier of power, natural gas and energy products and services for homes and businesses across the continental United States. It owns a diversified fleet of generating units, totaling approximately 12,000 megawatts of generating capacity, and is a leading advocate for clean, environmentally sustainable energy sources, such as solar power and nuclear energy. Baltimore Gas and Electric Company (BGE), Constellation's regulated utility, delivers electricity and natural gas in central Maryland. The resulting company will retain the Exelon name and be headquartered in Chicago. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on the Constellation transaction.

## Generation

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

At December 31, 2011, Generation owned generation resources with an aggregate net capacity of 25,544 MW, including 17,115 MW of nuclear capacity. Generation controlled another 5,025 MW of capacity through long-term contracts.

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

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

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

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

### *Generating Resources*

At December 31, 2011, the generating resources of Generation consisted of the following:

| Type of Capacity | MW |
|---|---|
| Owned generation assets [(a)] | |
| Nuclear | 17,115 |
| Fossil | 5,890 |
| Hydroelectric/Renewable | 2,539 |
| Owned generation assets | 25,544 |
| Long-term contracts [(b)] | 5,025 |
| Total generating resources | 30,569 |

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

Generation has three reportable segments, the Mid-Atlantic, Midwest, and South and West, representing the different geographical areas in which Generation's power marketing activities are conducted and where Generation's owned and contracted generating resources are located. Mid-Atlantic represents Generation's operations primarily in Pennsylvania, New Jersey and Maryland (approximately 35% of capacity); Midwest includes the operations in Illinois, Indiana, Michigan and Minnesota (approximately 45% of capacity); and the South and West includes operations primarily in Texas, Georgia, Oklahoma, Kansas, Missouri, Idaho and Oregon (approximately 20% of capacity).

***Nuclear Facilities***

Generation has ownership interests in eleven nuclear generating stations currently in service, consisting of 19 units with an aggregate of 17,115 MW of capacity. Generation wholly owns all of its nuclear generating stations, except for Quad Cities Generating Station (75% ownership), Peach Bottom Generating Station (50% ownership) and Salem Generating Station (Salem) (42.59% ownership). Generation's nuclear generating stations are all operated by Generation, with the exception of the two units at Salem, which are operated by PSEG Nuclear, LLC (PSEG Nuclear), an indirect, wholly owned subsidiary of PSEG. In both 2011 and 2010, electric supply (in GWh) generated from the nuclear generating facilities was 82% of Generation's total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. See Management's Discussion and Analysis of Financial Condition and Results of Operations for further discussion of Generation's electric supply sources.

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

During 2011 and 2010, the nuclear generating facilities operated by Generation achieved capacity factors of 93.3% and 93.9%, respectively. Generation aggressively manages its scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable generation base for Generation's short and long-term supply commitments and Power Team marketing and trading activities. During scheduled refueling outages, Generation performs maintenance and equipment upgrades in order to minimize the occurrence of unplanned outages and to maintain safe, reliable operations.

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

***Regulation of Nuclear Power Generation.*** Generation is subject to the jurisdiction of the NRC with respect to the operation of its nuclear generating stations, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously assesses unit performance indicators and inspection results, and communicates its assessment on a semi-annual basis. As of December 31, 2011, the NRC categorized each unit operated by Generation, with the exception of Byron Unit 2 and Limerick Unit 2, in the Licensee Response Column, which is the highest performance band. The NRC categorized Byron Unit 2 and Limerick Unit 2 in the Regulatory Response Column, which is the second highest performance band. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures for nuclear generating facilities and/or increased operating costs of nuclear generating units.

On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co. For additional information on the NRC actions related to the Japan Earthquake and Tsunami and the industry's response, see Management's Discussion and Analysis of Financial Condition and Results of Operations – Executive Overview.

***Licenses.*** Generation has 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals for Peach Bottom Units 2 and 3, Dresden Units 2 and 3, Quad Cities Units 1 and 2, Oyster Creek and Three Mile Island Unit 1. Additionally, PSEG has 40-year operating licenses from the NRC and on June 30, 2011, received 20-year operating license renewals for Salem Units 1 and 2. In December 8, 2010, in connection with an Administrative Consent Order (ACO) with the NJDEP, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. The following table summarizes the current operating license expiration dates for Generation's nuclear facilities in service:

| Station | Unit | In-Service Date (a) | Current License Expiration |
|---|---|---|---|
| Braidwood | 1 | 1988 | 2026 |
| | 2 | 1988 | 2027 |
| Byron | 1 | 1985 | 2024 |
| | 2 | 1987 | 2026 |
| Clinton | 1 | 1987 | 2026 |
| Dresden (b) | 2 | 1970 | 2029 |
| | 3 | 1971 | 2031 |
| LaSalle | 1 | 1984 | 2022 |
| | 2 | 1984 | 2023 |
| Limerick (c) | 1 | 1986 | 2024 |
| | 2 | 1990 | 2029 |
| Oyster Creek (b)(d) | 1 | 1969 | 2029 |
| Peach Bottom (b) | 2 | 1974 | 2033 |
| | 3 | 1974 | 2034 |
| Quad Cities (b) | 1 | 1973 | 2032 |
| | 2 | 1973 | 2032 |
| Salem (b) | 1 | 1977 | 2036 |
| | 2 | 1981 | 2040 |
| Three Mile Island (b) | 1 | 1974 | 2034 |

(a) Denotes year in which nuclear unit began commercial operations.
(b) Stations for which the NRC has issued a renewed operating licenses.
(c) On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years.
(d) In December, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.

On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years. Generation expects to apply for and obtain approval of license renewals for the remaining nuclear units. The operating license renewal process takes approximately four to five years from the commencement of the renewal process until completion of the NRC's review. The NRC review process takes approximately two years from the docketing of an application. Each requested license renewal is expected to be for 20 years beyond the original license expiration. Depreciation provisions are based on the estimated useful lives of the stations, which reflect the actual and assumed renewal of operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek.

***Nuclear Uprate Program.*** Generation has announced a series of planned power uprates across its nuclear fleet that would result in between 1,175 and 1,300 MWs at an overnight cost of approximately $3.30 billion in 2011 dollars. Overnight costs do not include financing costs or cost escalation. Using proven technologies, the projects take advantage of new production and measurement technologies, new materials and learning from a half-century of nuclear power operations. Uprate projects, representing approximately 75% of the planned uprate MWs, are underway at the Limerick, Three Mile Island and Peach Bottom nuclear stations in Pennsylvania and the Byron, Braidwood, Dresden, LaSalle and Quad Cities plants in Illinois. The remaining uprate MWs will come from additional projects across Generation's nuclear fleet beginning in 2012 and ending in 2017. At 1,300 nuclear-generated MWs, the uprates would displace 6 million metric tons of carbon emissions annually that would otherwise come from burning fossil fuels. The uprates are being undertaken pursuant to an organized, strategically sequenced implementation plan. The implementation effort includes a periodic review and refinement of the project in light of changing market conditions. The amount of expenditures to implement the plan ultimately will depend on economic and policy developments, and will be made on a project-by-project basis in accordance with Exelon's normal project evaluation standards. The ability to implement several projects requires the successful resolution of various technical issues. The resolution of these issues may affect the timing and amount of the power increases associated with the power uprate initiative. Through December 31, 2011, Generation has added 240 MWs of nuclear generation through its uprate program.

***New Nuclear Site Development.*** Generation is keeping open the option of a new nuclear plant located in Victoria County in southeast Texas; however, Generation has not made a decision to build a nuclear plant at this time. In response to the overall downturn of the economy and the projection of sustained, low natural gas prices, Exelon revised its new nuclear plant development strategy. Exelon had previously submitted a Combined Construction and Operating License (COL) application to the NRC for the Victoria site. On March 25, 2010, Exelon submitted an application for an Early Site Permit (ESP) application for the site and subsequently withdrew its COL application. The ESP allows Exelon to establish the suitability of the Victoria site, which lessens the amount of work necessary should Exelon later decide to reapply for a COL. Additionally, the ESP accommodates a variety of possible future plant designs, allowing for flexibility in selecting a reactor technology later as part of a COL application. If approved by the NRC, the ESP would effectively reserve the site for 20 years with the possibility of renewal for another 20 years. Any decision to build at the Victoria site would be made based on then-current economics. The original COL project spent the authorized $100 million. The Exelon board authorized an additional $30 million for the ESP project. The total project costs as of December 31, 2011 were $16 million. The current NRC review and approval schedule supports issuance of the ESP in late 2015.

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

As of December 31, 2011, Generation had approximately 56,300 SNF assemblies (13,500 tons) stored on site in SNF pools or dry cask storage (this includes SNF at Zion Station, for which Generation retains ownership, see Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning). On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at Generation's sites through the end of the license renewal periods, and through decommissioning. The following table describes the current status of Generation's SNF storage facilities.

| Site | Date for loss of full core reserve [(a)] |
|---|---|
| Braidwood | Dry cask storage in operation |
| Byron | Dry cask storage in operation |
| Clinton | 2016 |
| Dresden | Dry cask storage in operation |
| LaSalle | Dry cask storage in operation |
| Limerick | Dry cask storage in operation |
| Oyster Creek | Dry cask storage in operation |
| Peach Bottom | Dry cask storage in operation |
| Quad Cities | Dry cask storage in operation |
| Salem | Dry cask storage in operation |
| Three Mile Island [(b)] | 2023 |

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

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

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

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

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

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

For information regarding property insurance, see ITEM 2. Properties—Generation of Exelon's 2011 Form 10-K. Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for its insured losses. Such losses could have a material adverse effect on Exelon's and Generation's financial condition and results of operations.

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

Dresden Unit 1 and Peach Bottom Unit 1 have ceased power generation. SNF at Dresden Unit 1 is currently being stored in dry cask storage until a permanent repository under the NWPA is completed. All SNF for Peach Bottom Unit 1, which ceased operation in 1974, has been removed from the site and the SNF pool is drained and decontaminated. Generation's estimated liability to decommission Dresden Unit 1 and Peach Bottom Unit 1 was $183 million at December 31, 2011. As of December 31, 2011, NDT funds set aside to pay for these obligations were $351 million.

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

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

**Fossil, Hydroelectric and Renewable Facilities**

Generation operates various fossil, hydroelectric and renewable facilities and maintains ownership interests in several other facilities including LaPorte, Keystone, Conemaugh and Wyman, which are operated by third parties. In 2011 and 2010, electric supply (in GWh) generated from owned fossil, hydroelectric and renewable generating facilities was 7% 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 2011 Form 10-K.

***Antelope Valley Solar Ranch One.*** On September 30, 2011, Generation acquired Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, which developed and will build, operate, and maintain the project. Construction has started, with the first portion of the site expected to come online in late 2012 and full operation planned for late 2013. When fully operational, Antelope Valley will be one of the largest PV solar projects in the world, with approximately 3.8 million solar panels generating enough clean, renewable electricity to power the equivalent of 75,000 average homes per year. The project has a 25-year PPA, approved by the California Public Utilities Commission, with Pacific Gas & Electric Company for the full output of the plant. Exelon expects to invest up to $713 million in equity in the project through 2013. The DOE's Loan Programs Office issued a loan guarantee of up to $646 million to support project financing for Antelope Valley. Exelon expects the total investment of up to $1.36 billion to be accretive to earnings beginning in 2013 and to be accretive to cash flows starting in 2013. The project is expected to have stable earnings and cash flow profiles due to the PPA. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Antelope Valley acquisition.

***Wolf Hollow Generating Station.*** On August 24, 2011, Generation completed the acquisition of the equity interest of Wolf Hollow, LLC (Wolf Hollow), a combined-cycle natural gas-fired power plant in north Texas, for a purchase price of $311 million pursuant to which Generation added 720 MWs of capacity within the ERCOT power market. Generation recognized a $42 million gain as part of the transaction. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Wolf Hollow acquisition.

***Exelon Wind.*** In 2010, Generation acquired 735 MWs of installed, operating wind capacity located in eight states for approximately $893 million in cash. On January 1, 2012, Michigan Wind 2, one of the Exelon Wind development projects acquired in 2010, began commercial operations. The facility has a capacity of approximately 90MWs. In addition, Generation is currently developing additional wind projects in Michigan with a combined capacity of approximately 140 MWs. See Note 3 and Note 1 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Exelon Wind acquisition and new site development costs, respectively.

***Plant Retirements.*** On May 31, 2011, Cromby Generating Station (Cromby) Unit 1 and Eddystone Generating Station (Eddystone) Unit 1 were retired; on December 31, 2011, Cromby Unit 2 was retired and Eddystone Unit 2 will retire on May 31, 2012. For more information regarding plant retirements, see Note 14 of the Combined Notes to Consolidated Financial Statements.

***Licenses.*** Fossil and renewable generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways or Federal lands, or connected to the interstate electric grid. The license for the Conowingo Hydroelectric Project expires on August 31, 2014 and for the Muddy Run Pumped Storage Facility Project expires on September 1, 2014. In March 2009, Generation filed a Pre-Application Document and Notice of Intent to renew the licenses, pursuant to FERC relicensing requirements. Generation plans to file license applications with FERC for both facilities in August 2012. For those plants located within the control areas administered by PJM, notice is required to be provided before a plant can be retired.

***Insurance.*** Generation maintains business interruption insurance for its wind and solar PV projects, and delay in start-up insurance for its wind and solar PV projects currently under construction. 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's 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 2011 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, 2011:

| Seller | Location | Expiration | Capacity (MW) |
|---|---|---|---|
| Kincaid Generation, LLC | Kincaid, Illinois | 2013 | 1,108 |
| Tenaska Georgia Partners, L.P. [(a)] | Franklin, Georgia | 2030 | 945 |
| Tenaska Frontier Partners, Ltd. [(b)] | Shiro, Texas | 2020 | 830 |
| Green Country Energy, LLC [(c)] | Jenks, Oklahoma | 2022 | 778 |
| Elwood Energy, LLC | Elwood, Illinois | 2012 | 775 |
| Old Trail Windfarm, LLC | McLean, Illinois | 2026 | 198 |
| Others [(d)] | Various | 2012 to 2028 | 391 |
| Total | | | 5,025 |

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

(b) On December 17, 2009, Generation entered into a PPA with Entergy Texas, Inc. (ETI) to sell 150 MWs through April 30, 2011 and 300 MWs thereafter of capacity and energy from the Frontier Generating Station. The term of the PPA is approximately 10 years.

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

(d) Includes long-term capacity contracts with six counterparties.

### *Fuel*

The following table shows sources of electric supply in GWh for 2011 and estimated for 2012:

| | Source of Electric Supply [a] | |
|---|---|---|
| | **2011** | **2012 (Est.)** |
| Nuclear | 139,297 | 141,316 |
| Purchases—non-trading portfolio | 18,908 | 18,397 |
| Fossil and renewable | 11,638 | 16,466 |
| Total supply | 169,843 | 176,179 |

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

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

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride and the fabrication of fuel assemblies. Generation has uranium concentrate inventory and supply contracts sufficient to meet all of its uranium concentrate requirements through 2015. Generation's contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2015. All of Generation's enrichment requirements have been contracted through 2017. Contracts for fuel fabrication have been obtained through 2013. Generation does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or fabrication services to meet the nuclear fuel requirements of its nuclear units.

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

Generation uses financial instruments to mitigate price risk associated with certain commodity price exposures. Generation also hedges forward price risk with both over-the-counter and exchange-traded instruments. See ITEM 1A. Risk Factors of Exelon's 2011 Form 10-K and Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates and Note 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

### Power Team

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

Generation also manages the price and supply risks for energy and fuel associated with generation assets and the risks of power marketing activities. Generation implements a three-year ratable sales plan to align its hedging strategy with its financial objectives. Generation also enters into transactions that are outside of this ratable sales plan, such as a financial swap with ComEd that is described below and runs into 2013. However, except for the ComEd swap arrangement, Generation is exposed to relatively greater commodity price risk beyond 2012 for which a larger portion of its electricity portfolio may be unhedged. Generation has been and will continue to be proactive in using hedging strategies to mitigate this risk in subsequent years. As of December 31, 2011, the percentage of expected generation hedged was 88%-91%, 61%-64% and 32%-35% for 2012, 2013 and 2014, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include cash flow hedges, other derivatives and certain non-derivative contracts, including sales to ComEd and PECO to serve their retail load. A portion of Generation's hedging strategy may be implemented through the use of fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. The trading portfolio is subject to a risk management policy that includes stringent risk management limits including volume, stop-loss and value-at-risk limits to manage exposure to market risk. Additionally, the corporate risk management group and Exelon's RMC monitor the financial risks of the power marketing activities. Generation also uses financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of Generation's efforts.

At December 31, 2011, Generation's short and long-term commitments relating to the sale and purchase 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) |
|---|---|---|---|---|
| 2012 | $177 | $ 11 | $1,150 | $ 9 |
| 2013 | 71 | — | 834 | 6 |
| 2014 | 63 | — | 346 | — |
| 2015 | 61 | — | 200 | — |
| 2016 | 61 | — | 177 | — |
| Thereafter | 478 | — | 737 | — |
| Total | $911 | $ 11 | $3,444 | $ 15 |

(a) Net capacity purchases include PPAs and other capacity contracts that are accounted for as operating leases. Amounts presented as commitments represent Generation's expected payments under these arrangements at December 31, 2011, including certain capacity charges, which are subject to plant availability.

(b) Excludes renewable energy PPA contracts that are contingent in nature.

(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

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

PECO procures all of its electricity through a competitive procurement process, through which Generation will continue to supply a portion of PECO's load. See PECO—Retail Electric Services, Procurement Related Proceedings for additional information regarding PECO's competitive, full-requirements energy-supply procurement process.

### *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 2012 are as follows:

| (in millions) | |
|---|---|
| Nuclear fuel [(a)] | $1,173 |
| Production plant | 844 |
| Uprates | 450 |
| Renewable energy projects [(b)] | 1,301 |
| Total | $3,768 |

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

(b) Includes expenditures for Antelope Valley and Exelon Wind development projects.

## ComEd

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

ComEd's retail service territory has an area of approximately 11,400 square miles and an estimated population of 9 million. The service territory includes the City of Chicago, an area of about 225 square miles with an estimated population of 3 million. ComEd has approximately 3.8 million customers.

ComEd's franchises are sufficient to permit it to engage in the business it now conducts. ComEd's franchise rights are generally nonexclusive rights documented in agreements and, in some cases, certificates of public convenience issued by the ICC. With few exceptions, the franchise rights have stated expiration dates ranging from 2012 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 July 20, 2011 and was 23,753 MWs; its highest peak load during a winter season occurred on January 15, 2009 and was 16,328 MWs.

### *Retail Electric Services*

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

At December 31, 2011, approximately 380,300 retail customers representing approximately 56% 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 the current regulatory mechanisms in effect, ComEd is permitted to recover its electricity procurement costs from retail customers, without mark-up. Thus, although energy sales affect ComEd's reported revenues, they do not affect its net income, as the energy sales are offset by an equal amount of purchased power expense.

Under Illinois law, ComEd is required to deliver electricity to all customers. ComEd's obligation to provide generation supply service, which is referred to as a POLR obligation, primarily varies by customer size. ComEd's obligation to provide such service to residential customers and other small customers with demands of under 100 kWs continues for all customers who do not or cannot choose a competitive electric generation supplier or who choose to return to ComEd after taking service from a competitive electric generation supplier. ComEd does not have a fixed-price generation supply service obligation to most of its largest customers with demands of 100 kWs or greater, as this group of customers has previously been declared competitive. Customers with competitive declarations may still purchase power and energy from ComEd, but only at hourly market prices.

*Legislation to Modernize Electric Utility Infrastructure and to Update Illinois Ratemaking Process.* On October 26, 2011, the Illinois General Assembly overrode the Governor's veto of the Illinois Energy Infrastructure Modernization Act (SB 1652), which became effective immediately. The Illinois General Assembly also passed House Bill 3036 (the Trailer Bill), which modifies and supplements SB 1652. The Governor signed the Trailer Bill into law on December 30, 2011. The combined legislation (EIMA) provides for substantial capital investment over a ten-year period to modernize Illinois' electric utility infrastructure and for greater certainty related to the recovery of costs by a utility through a pre-established distribution formula rate tariff. Under the terms of EIMA, ComEd's target rate of return on common equity is subject to reduction if ComEd does not deliver the reliability and customer service benefits, as defined, it has committed to over the ten-year life of the investment program. In addition, ComEd will make contributions to fund customer assistance programs and for a new Science and Technology Innovation Trust fund. The legislation also contains a provision for the IPA to conduct procurement events for energy and REC requirements for the June 2013 through December 2017 period. In order to protect consumers, EIMA contains several restrictions and potential criteria for early termination, ending ComEd's investment commitment and the performance-based formula rates.

On November 8, 2011, ComEd filed its initial formula rate tariff and associated testimony based on 2010 costs and 2011 plant additions. The ICC will review ComEd's rate filing to evaluate the prudence and reasonableness of the costs and issue its order in a shortened proceeding. This rate will take effect 30 days after the ICC order, which must be issued by May 31, 2012. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

*Electric Distribution Rate Cases.* The ICC issued an order in ComEd's 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd's annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a 10.3% rate of return on common equity. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). On September 30, 2010, the Court issued a decision in those appeals. That decision ruled against ComEd on the treatment of post-test year accumulated depreciation and the recovery of costs for an AMI/ Customer Applications pilot program via a rider (Rider SMP). ComEd's Petition for Leave to Appeal to the Illinois Supreme Court was denied on March 30, 2011. The ICC has initiated a proceeding on remand. ComEd expects that the ICC will issue a final order in early 2012. ComEd filed testimony that no refunds should be required in this proceeding and, in the event of any refund, the maximum refund should be $30 million. On November 10, 2011, the ALJ issued a proposed order in the remand proceeding agreeing with ComEd that the ICC does not have the legal authority to order a refund; a refund may only be ordered by a court. The ALJ also concluded that, to the extent that a court orders a refund, it should be in the amount of $37 million, including interest. As of December 31, 2011, ComEd has recognized for accounting purposes its best estimate of any refund obligation, subject to reconciliation when the ICC issues a final order. ComEd does not believe any of its other riders are affected by the Court's ruling.

On May 24, 2011, the ICC issued an order in ComEd's 2010 electric distribution rate case, which became effective on June 1, 2011. The order approved a $143 million increase to ComEd's annual delivery services revenue requirement and a 10.5% rate of return on common equity. The order allowed ComEd to establish or reestablish a net amount of approximately $40 million of previously expensed plant balances or new regulatory assets, which is reflected as a reduction in operating and maintenance expense and income tax expense for the year ended December 31, 2011. The order has been appealed to the Court by several parties. ComEd cannot predict the results of these appeals. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electric distribution rate cases.

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

*Continuous Power Interruption.* Illinois law provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) 30,000 or more customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law. ComEd does not believe that during the years 2011, 2010 and 2009 it had any interruptions that have triggered this damage liability or reimbursement requirement.

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable under provisions of the Illinois Public Utilities Act that could require damage compensation to customers in connection with the July 11, 2011 storm system that affected more than 900,000 customers in ComEd's service territory, as well as five other storm systems that affected ComEd's customers during June and July 2011. In the absence of a favorable determination from the ICC, some ComEd customers affected by the outages could seek recovery of their actual, non-consequential damages, and the local governments in which those customers are located could seek recovery of emergency and contingency expenses. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.

***Construction Budget***

ComEd's business is capital intensive and requires significant investments primarily in energy transmission and distribution facilities, to ensure the adequate capacity and reliability of its system. Based on PJM's RTEP, ComEd has various construction commitments, as discussed in Note 2 of the Combined Notes to Consolidated Financial Statements. ComEd's most recent estimate of capital expenditures for electric plant additions and improvements for 2012 is $1,330 million, which includes RTEP projects and infrastructure modernization resulting from EIMA. See Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources for further information.

**PECO**

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

PECO's combined electric and natural gas retail service territory has an area of approximately 2,100 square miles and an estimated population of 4.0 million. PECO provides electric distribution service in an area of approximately 1,900 square miles, with a population of approximately 3.9 million, including approximately 1.5 million in the City of Philadelphia. PECO provides natural gas distribution service in an area of approximately 1,900 square miles in southeastern Pennsylvania adjacent to the City of Philadelphia, with a population of approximately 2.4 million. PECO delivers electricity to approximately 1.6 million customers and natural gas to approximately 494,000 customers.

PECO has the necessary authorizations to provide regulated electric and natural gas distribution 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; however, PECO does not consider those situations as posing a material competitive or financial threat.

PECO's kWh sales and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. PECO's highest peak load occurred on July 22, 2011 and was 8,983 MW; its highest peak load during winter months occurred on December 20, 2004 and was 6,838 MW.

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

***Retail Electric Services***

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

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

Pennsylvania permits competition by EGSs for the supply of retail electricity while retail transmission and distribution service remains regulated under the Competition Act. At December 31, 2011, there were 59 alternative EGSs serving PECO customers. At December 31, 2011, the number of retail customers purchasing energy from an alternative EGS was 387,628, representing approximately 25% of total retail customers. Retail deliveries purchased from EGSs represented approximately 57% of PECO's retail kWh sales for the year ended December 31, 2011. This represents a significant increase from prior years due to the expiration of electric generation rate caps that were lower than market prices during the transition period. Customers that choose an alternative EGS are not subject to rates for PECO's electric supply procurement costs and retail transmission service charges. PECO presents on customer bills its electric supply Price to Compare, which is updated quarterly, to assist customers with the evaluation of offers from alternative EGSs.

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

*Electric Distribution Rate Case.* In December 2010, the PAPUC approved a settlement of PECO's electric distribution rate case filed in August 2010 that provides for an annual revenue increase of $225 million. The approved electric distribution rates became effective on January 1, 2011.

*Procurement Proceedings.* Prior to January 1, 2011, PECO procured all its electric supply under a full requirements PPA with Generation, which expired on December 31, 2010. The term and procurement costs under the PPA with Generation corresponded with PECO's transition period and capped electric generation rates in accordance with its 1998 restructuring settlement. Beginning January 1, 2011, PECO's electric supply for its customers is procured through contracts executed in accordance with its current PAPUC-approved DSP Program. PECO has entered into contracts with PAPUC-approved bidders as part of its six competitive procurements conducted since June 2009 for its default electric supply beginning January 2011, which included fixed price full requirement contracts for all procurement classes, spot market price full requirements contracts for the commercial and industrial procurement classes, and block energy contracts for the residential procurement class. PECO will conduct three additional competitive procurements for electric supply for all customer classes during the term of its current DSP Program, which expires on May 31, 2013.

On January 13, 2012, PECO filed its second Default Service Plan for approval with the PAPUC, which outlined how PECO will purchase electric supply for default service customers from June 1, 2013 through May 31, 2015. The plan proposed to procure electric supply through a combination of one-year and two-year fixed full requirements contracts, reduce the amount of time between when the energy is purchased and when it is provided to customers and complete an annual, rather than quarterly, reconciliation of costs for actual versus forecasted energy use. The plan also proposed several new programs to continue PECO's support of retail market competition in Pennsylvania in accordance with the order issued by the PAPUC on December 15, 2011. Hearings on the filing will be held in the summer of 2012 with a PAPUC ruling expected in mid-October 2012.

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

***Smart Meter and Energy Efficiency Programs***

*Smart Meter Programs.* In April 2010, the PAPUC approved PECO's $550 million Smart Meter Procurement and Installation Plan, which was filed in accordance with the requirements of Act 129. Also, in April 2010, PECO entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA of 2009. Under the SGIG, PECO has been awarded $200 million, the maximum grant allowable under the program, for its SGIG project – Smart Future Greater Philadelphia. As a result of the SGIG funding, PECO will deploy 600,000 smart meters by 2013, accelerate universal deployment of more than 1.6 million smart meters by 2020 and increase smart grid investments to approximately $100 million through 2013. In total, through 2020, PECO plans to spend up to $650 million on its smart grid and smart meter infrastructure. The SGIG funding will be used to significantly reduce the impact of those investments on PECO customers.

*Energy Efficiency Programs.* PECO's approved four-year EE&C plan totals approximately $328 million and includes a CFL program, weatherization programs, an energy efficiency appliance rebate and trade-in program, rebates and energy efficiency programs for non-profit, educational, governmental and business customers, customer incentives for energy management programs and incentives to help customers reduce energy demand during peak periods. In July 2011, PECO filed a petition to make adjustments to its EE&C Plan. The filing noted that PECO has exceeded the 1% energy use reduction target required by May 31, 2011 in accordance with Act 129; the adjustments, which were approved by the PAPUC on August 18, 2011, will allow PECO to meet its May 31, 2013 targets for energy use and energy demand reductions, while remaining within its approved plan budget.

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

### *Natural Gas*

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

PECO's natural gas customers have the right to choose their natural gas suppliers or to purchase their gas supply from PECO at cost. In 2011, 40% of PECO's current total yearly throughput was provided by natural gas suppliers other than PECO, of which, 34% was for commercial and industrial customers participating in PECO's High Volume Transportation Program and 6% was for residential and small commercial customers participating in PECO's Low Volume Transportation Choice Program. PECO provides distribution service, billing, metering, installation, maintenance and emergency response services at regulated rates to all customers in PECO's service territory.

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

*Procurement Proceedings.* PECO's natural gas supply is purchased from a number of suppliers primarily under long-term firm transportation contracts for terms of up to two years in accordance with its annual PAPUC PGC settlement. PECO's aggregate annual firm supply under these firm transportation contracts is 46 million dekatherms. Peak natural gas is provided by PECO's liquefied natural gas (LNG) facility and propane-air plant. PECO also has under contract 23 million dekatherms of underground storage through service agreements. Natural gas from underground storage represents approximately 30% of PECO's 2011-2012 heating season planned supplies.

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

### *Construction Budget*

PECO's business is capital intensive and requires significant investments primarily in electric transmission and electric and natural gas distribution facilities to ensure the adequate capacity, reliability and efficiency of its system. PECO, as a transmission facilities owner, has various construction commitments under PJM's RTEP as discussed in Note 2 of the Combined Notes to Consolidated Financial Statements. PECO's most recent estimate of capital expenditures for plant additions and improvements for 2012 is $436 million, which includes capital expenditures related to the smart meter program and SGIG project net of DOE expected reimbursements.

## ComEd and PECO

### *Transmission Services*

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

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

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

As a result of PECO's 1998 restructuring settlement, retail transmission rates were capped at the level in effect on December 31, 1996, which remained unchanged through December 31, 2010. Beginning January 1, 2011, PECO default service customers are charged for retail transmission services through a rider designed to recover PECO's PJM transmission network service charges and RTEP charges on a full and current basis in accordance with the 2010 electric distribution rate case settlement.

The transmission rate in the PJM Open Access Transmission Tariff under which PECO incurs costs to serve its default service customers and earns revenue as a transmission facility owner is a FERC-approved rate. This is the rate that all load serving entities in the PECO transmission zone pay for wholesale transmission service.

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

**Environmental Regulation**

***General***

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

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

***Water***

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

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

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

### *Solid and Hazardous Waste*

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

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

### *Environmental Remediation*

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

The amount to be expended in 2012 at Exelon for compliance with environmental remediation is expected to total $32 million, consisting of $26 million and $6 million at ComEd and PECO, respectively. In addition, Generation, ComEd and PECO may be required to make significant additional expenditures not presently determinable.

Generation's environmental liabilities primarily arise from contamination at current or former generation facilities. As of December 31, 2011, Generation has established an appropriate accrual to comply with environmental remediation requirements which includes an accrual for contamination attributable to low level radioactive residues at a storage and reprocessing facility named Latty Avenue near St. Louis, Missouri formerly owned by Cotter Corporation, a former ComEd subsidiary.

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

### *Air*

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

See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information regarding clean air regulation and legislation in the forms of the CSAPR, the regulation of hazardous air pollutants from coal- and oil-fired electric generating facilities under the Mercury and Air Toxics (MATS) rule, and regulation of GHG emissions, in addition to NOVs issued to Generation and ComEd for alleged violations of the Clean Air Act.

***Global Climate Change***

Exelon believes the evidence of global climate change is compelling and that the energy industry, though not alone, is a significant contributor to the human-caused emissions of GHGs that many in the scientific community believe contribute to global climate change, as reported by the National Academy of Sciences in May 2011. Exelon, as a producer of electricity from predominantly low-carbon generating facilities (such as nuclear, hydroelectric, wind and solar photovoltaic), has a relatively small GHG emission profile, or carbon footprint, compared to other domestic generators of electricity. By virtue of its significant investment in low-carbon intensity assets, Generation's emission intensity, or rate of carbon dioxide equivalent ($CO_2e$) emitted per unit of electricity generated, is among the lowest in the industry. Exelon does produce GHG emissions, primarily at its fossil fuel-fired generating plants; $CO_2$, methane and nitrous oxide are all emitted in this process, with $CO_2$ representing the largest portion of these GHG emissions. GHG emissions from Generation's combustion of fossil fuels represent approximately 90% of Exelon's total GHG emissions. However, only approximately 5% of Exelon's total electric supply is provided by its fossil fuel generating plants. Other GHG emission sources at Exelon include natural gas (methane) leakage on the gas pipeline system and the coal piles at its generating plants, sulfur hexafluoride ($SF_6$) leakage in its electric operations and refrigerant leakage from its chilling and cooling equipment as well as fossil fuel combustion in its motor vehicles and usage of electricity in its facilities. Despite its small carbon footprint, Exelon believes its operations could be significantly affected by the possible physical risks of climate change and by mandatory programs to reduce GHG emissions. See ITEM 1A. Risk Factors of Exelon's 2011 Form 10-K for information regarding the market and financial, regulatory and legislative, and operational risks associated with climate change.

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

*International Climate Change Regulation.* At the international level, the United States is currently not a party to the Kyoto Protocol, which is a protocol to the United Nations Framework Convention on Climate Change (UNFCCC) and became effective for signatories on February 16, 2005. The United Nations' Kyoto Protocol process generally requires developed countries to cap GHG emissions at certain levels during the 2008-2012 time period. At the conclusion of the December 2011 United Nations Framework Convention on Climate Change (COP 17) Conference in Durban, South Africa, a package of decisions was adopted that initiate another commitment phase for the Kyoto Protocol and initiating a new round of discussions with the objective of establishing a successor agreement by 2015 that would commence beginning in 2020. These decisions build on the agreements reached in the 2009 Copenhagen Accord, including the United States agreeing to undertake a number of voluntary measures, including the establishment of a goal to reduce GHG emissions and contributions toward a fund to assist developing nations to address their GHG emissions.

*Federal Climate Change Legislation and Regulation.* Various stakeholders, including Exelon, legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors are considering ways to address the climate change issue. It is uncertain when any mandatory programs to reduce GHG emissions would be established 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 to procure emission allowances or credits.

The U.S. EPA is addressing the issue of GHG emissions regulation for new stationary sources through its proposed New Source Performance Standard under the existing provisions of the Clean Air Act. Such proposed regulation has the potential to cause Exelon to incur material costs of compliance for GHG emissions from stationary sources.

*Regional and State Climate Change Legislation and Regulation.* At a regional level, on November 15, 2007, six Midwest state Governors (Illinois, Iowa, Kansas, Michigan, Minnesota and Wisconsin) signed the Midwestern Greenhouse Gas Accord. Under that Accord, an inter-state work group was formed to establish a Midwestern GHG Reduction Program that will: (1) establish GHG reduction targets and timeframes consistent with member state targets; (2) develop a market-based and multi-sector cap-and-trade program to help achieve GHG reductions; and (3) develop other mechanisms and policies to assist in meeting GHG reduction targets (e.g. a low carbon fuel standard). In May 2010, an advisory group appointed by the Governors issued recommendations, but no actions have been taken on the recommendations.

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

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

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

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

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

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

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

***Renewable and Alternative Energy Portfolio Standards***

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

The Illinois Settlement Legislation required that procurement plans implemented by electric utilities include cost-effective renewable energy resources or approved equivalents such as RECs in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers by June 1, 2008, increasing to 10% by June 1, 2015, with a goal of 25% by

June 1, 2025. Utilities are allowed to pass-through any costs from the procurement of these renewable resources or approved equivalents subject to legislated rate impact criteria. As of December 31, 2011, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. See Note 2 and Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.

The AEPS Act was effective for PECO on January 1, 2011, following the expiration of PECO's transition period. During 2011, PECO was required to supply approximately 3.5% and 6.2% of electric energy generated from Tier I (including solar, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, fuel cells, biomass energy, coal mine methane and black liquor generated within Pennsylvania) and Tier II (including waste coal, demand-side management, large-scale hydropower, municipal solid waste, generation of electricity utilizing by-products of the pulping process and wood, distributed generation systems and integrated combined coal gasification technology) alternative energy resources, respectively, as measured in AECs. The compliance requirements will incrementally escalate to 8.0% for Tier I and 10.0% for Tier II by 2021. In order to comply with these requirements, PECO entered into agreements with varying terms with accepted bidders, including Generation, to purchase non-solar Tier I, solar Tier 1 and Tier II AECs. PECO also purchases AECs through its DSP Program full requirement contracts.

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

See Note 2 and Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.

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

## MARKET FOR OUR COMMON EQUITY RELATED STOCKHOLDER MATTERS

### Exelon

Exelon's common stock is listed on the New York Stock Exchange. As of January 31, 2012, there were 663,640,976 shares of common stock outstanding and approximately 125,092 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:

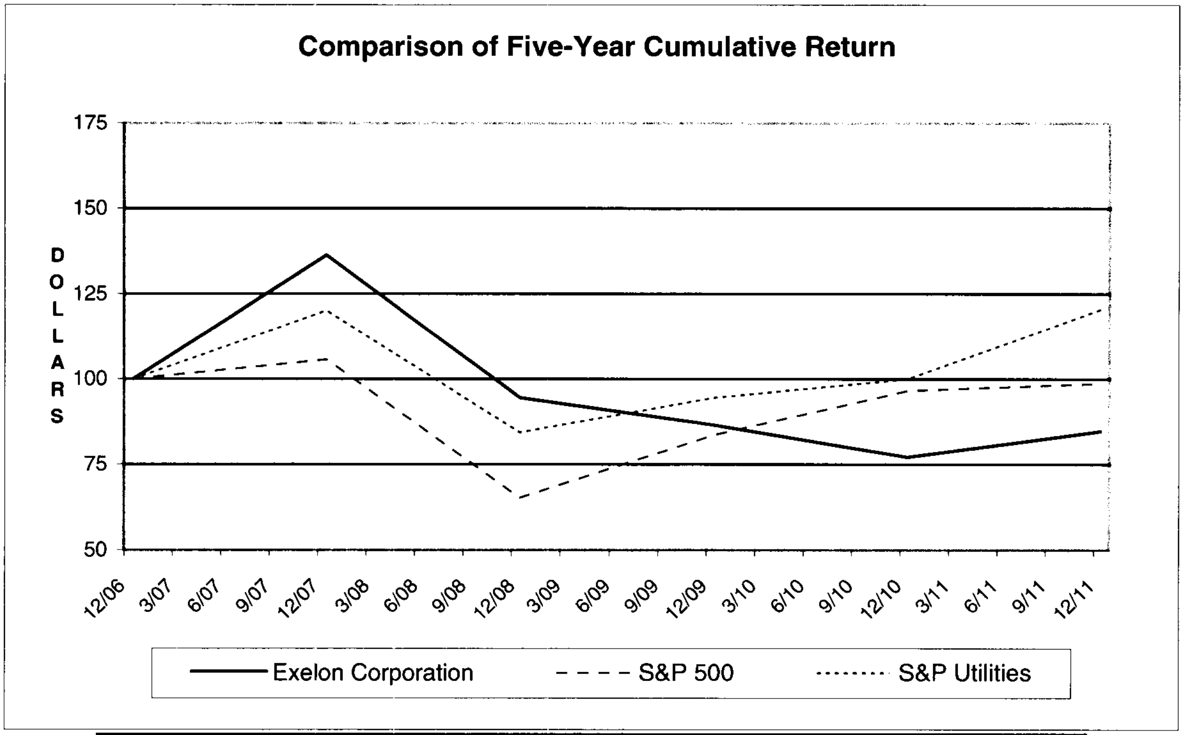
| | 2011 | | | | 2010 | | | |
|---|---|---|---|---|---|---|---|---|
| | Fourth Quarter | Third Quarter | Second Quarter | First Quarter | Fourth Quarter | Third Quarter | Second Quarter | First Quarter |
| High price | $45.45 | $45.27 | $42.89 | $43.58 | $44.49 | $43.32 | $45.10 | $49.88 |
| Low price | 39.93 | 39.51 | 39.53 | 39.06 | 39.05 | 37.63 | 37.24 | 42.97 |
| Close | 43.37 | 42.61 | 42.84 | 41.24 | 41.64 | 42.58 | 37.97 | 43.81 |
| Dividends | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 |

### Stock Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in Exelon common stock, as compared with the S&P 500 Stock Index and the S&P Utility Index for the period 2007 through 2011.

This performance chart assumes:

- $100 invested on December 31, 2006 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and
- All dividends are reinvested.




| | Value of Investment at December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
| Exelon Corporation | $100.00 | $135.06 | $94.71 | $86.88 | $77.86 | $85.17 |
| S&P 500 | $100.00 | $105.48 | $66.52 | $84.07 | $96.71 | $98.76 |
| S&P Utilities | $100.00 | $119.34 | $84.81 | $94.83 | $99.99 | $119.83 |

### 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 a financing arranged through ComEd Financing III that ComEd 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. No such event has occurred.

PECO's Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. At December 31, 2011, such capital was $2.9 billion and amounted to about 34 times the liquidating value of the outstanding preferred securities of $87 million.

PECO has agreed in connection with financings arranged through PEC L.P. and PECO Trust IV that PECO 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 debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued. No such event has occurred.

At December 31, 2011, Exelon had retained earnings of $10,055 million, including Generation's undistributed earnings of $4,232 million, ComEd's retained earnings of $447 million consisting of retained earnings appropriated for future dividends of $2,086 million, partially offset by $1,639 million of unappropriated retained deficits, and PECO's retained earnings of $559 million.

The following table sets forth Exelon's quarterly cash dividends per share paid during 2011 and 2010:

| | 2011 | | | | 2010 | | | |
|---|---|---|---|---|---|---|---|---|
| **(per share)** | **4th Quarter** | **3rd Quarter** | **2nd Quarter** | **1st Quarter** | **4th Quarter** | **3rd Quarter** | **2nd Quarter** | **1st Quarter** |
| Exelon | $0.525 | $0.525 | $0.525 | $0.525 | $0.525 | $0.525 | $0.525 | $0.525 |

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

| | 2011 | | | | 2010 | | | |
|---|---|---|---|---|---|---|---|---|
| **(in millions)** | **4th Quarter** | **3rd Quarter** | **2nd Quarter** | **1st Quarter** | **4th Quarter** | **3rd Quarter** | **2nd Quarter** | **1st Quarter** |
| Generation | $111 | $61 | $— | $— | $885 | $206 | $156 | $261 |
| ComEd | 75 | 75 | 75 | 75 | 85 | 75 | 75 | 75 |
| PECO | 80 | 84 | 73 | 111 | 46 | 63 | 51 | 64 |

***First Quarter 2012 Dividend.*** On October 25, 2011, the Exelon Board of Directors declared a first quarter 2012 regular quarterly dividend of $0.525 per share on Exelon's common stock payable on March 9, 2012, to shareholders of record of Exelon at the end of the day on February 15, 2012.

***Second Quarter 2012 Dividend.*** In addition, on January 24, 2012, the Exelon Board of Directors declared a second quarter 2012 regular quarterly dividend of $0.525 per share on Exelon's common stock contingent on the pending merger with Constellation. If the effective date of the merger is after May 15, 2012, the Board of Directors declared a regular quarterly dividend of $0.525 per share on Exelon's common stock, payable on June 8, 2012, to shareholders of record of Exelon at the end of the day on May 15, 2012.

If the effective date of the merger is on or before May 15, 2012, shareholders will receive two separate dividend payments totaling $0.525 per share:

- The first of the dividend payments will be pro-rated, with shareholders of record as of the end of day before the effective date of the merger receiving $0.00583 per share per day for the period from and including February 16, 2012, the day after the record date for the previous dividend, through and including the day before the effective date of the merger. This portion of the dividend will be paid within 30 days after the effective date of the merger.
- The second of the dividend payments will also be pro-rated, with all Exelon shareholders, including the former Constellation shareholders, of record at the end of the day on May 15, 2012, receiving $0.00583 per share per day for the period from and including the effective date of the merger through and including May 15, 2012. This portion of the dividend will be paid on June 8, 2012.

## SELECTED FINANCIAL DATA

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

| (In millions, except per share data) | For the Years Ended December 31, 2011 | 2010 | 2009 | 2008 | 2007 |
|---|---|---|---|---|---|
| **Statement of Operations data:** | | | | | |
| Operating revenues | $18,924 | $18,644 | $17,318 | $18,859 | $18,916 |
| Operating income | 4,480 | 4,726 | 4,750 | 5,299 | 4,668 |
| Income from continuing operations | $ 2,495 | $ 2,563 | $ 2,706 | $ 2,717 | $ 2,726 |
| Income from discontinued operations | — | — | 1 | 20 | 10 |
| Net income | $ 2,495 | $ 2,563 | $ 2,707 | $ 2,737 | $ 2,736 |
| Earnings per average common share (diluted): | | | | | |
| Income from continuing operations | $ 3.75 | $ 3.87 | $ 4.09 | $ 4.10 | $ 4.03 |
| Income from discontinued operations | — | — | — | 0.03 | 0.02 |
| Net income | $ 3.75 | $ 3.87 | $ 4.09 | $ 4.13 | $ 4.05 |
| Dividends per common share | $ 2.10 | $ 2.10 | $ 2.10 | $ 2.03 | $ 1.76 |
| Average shares of common stock outstanding—diluted | 665 | 663 | 662 | 662 | 676 |

| (In millions) | December 31, 2011 | 2010 | 2009 | 2008 (a) | 2007 (a)(b) |
|---|---|---|---|---|---|
| **Balance Sheet data:** | | | | | |
| Current assets | $ 5,489 | $ 6,398 | $ 5,441 | $ 5,130 | $ 4,416 |
| Property, plant and equipment, net | 32,570 | 29,941 | 27,341 | 25,813 | 24,153 |
| Noncurrent regulatory assets | 4,839 | 4,140 | 4,872 | 5,940 | 5,133 |
| Goodwill | 2,625 | 2,625 | 2,625 | 2,625 | 2,625 |
| Other deferred debits and other assets | 9,569 | 9,136 | 8,901 | 8,038 | 8,760 |
| Total assets | $55,092 | $52,240 | $49,180 | $47,546 | $45,087 |
| Current liabilities | $ 4,989 | $ 4,240 | $ 4,238 | $ 3,811 | $ 5,466 |
| Long-term debt, including long-term debt to financing trusts | 12,189 | 12,004 | 11,385 | 12,592 | 11,965 |
| Noncurrent regulatory liabilities | 3,771 | 3,555 | 3,492 | 2,520 | 3,301 |
| Other deferred credits and other liabilities | 19,668 | 18,791 | 17,338 | 17,489 | 14,131 |
| Preferred securities of subsidiary | 87 | 87 | 87 | 87 | 87 |
| Noncontrolling interest | 3 | 3 | — | — | — |
| Shareholders' equity | 14,385 | 13,560 | 12,640 | 11,047 | 10,137 |
| Total liabilities and shareholders' equity | $55,092 | $52,240 | $49,180 | $47,546 | $45,087 |

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

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

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

### General

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

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

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

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

### Executive Overview

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

Exelon's net income was $2,495 million for the year ended December 31, 2011 as compared to $2,563 million for the year ended December 31, 2010, and diluted earnings per average common share were $3.75 for the year ended December 31, 2011 as compared to $3.87 for the year ended December 31, 2010.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, decreased by $413 million primarily related to a decrease in CTC recoveries at PECO of $995 million as a result of the end of the transition period on December 31, 2010. This impact on Exelon's operating income was partially offset by decreased CTC amortization expense discussed below. Mark-to-market losses of $288 million in 2011 from Generation's hedging activities compared to $86 million in mark-to-market gains in 2010 also had an unfavorable impact on Generation's operating results. In addition, Generation's operating revenue net of purchased power and fuel expense decreased by $534 million in the Midwest due to decreased realized margins in 2011 for volumes previously sold under the 2006 ComEd auction contracts and increased nuclear fuel costs. Partially offsetting these unfavorable impacts were increased operating revenues net of purchased power and fuel expense at Generation of $847 million in the Mid-Atlantic due to increased margins on volumes previously sold under Generation's PPA with PECO, which expired on December 31, 2010, and increased operating revenues net of purchased power and fuel expense of $201 million in the South and West primarily driven by the performance of Exelon's generating units during extreme weather events that occurred in Texas in February and August of 2011. Operating revenue net of purchased power and fuel expense in the South and West was also impacted favorably by additional revenues from Exelon Wind, which was acquired in December 2010, and higher realized margins due to overall favorable market conditions. The decrease in revenue net of purchased power and fuel expense was also partially offset by the 2010 impact of the impairment charge of certain emission allowances, as well as compensation under the reliability-must-run rate schedule received in 2011. ComEd's and PECO's operating revenues net of purchased power and fuel expense increased by $89 million and $155 million, respectively, as a result of improved pricing primarily due to the new electric distribution rates effective June 1, 2011 at ComEd and new electric and natural gas distribution rates effective January 1, 2011 at PECO. ComEd's operating revenues also increased by $29 million as a result of increased ComEd distribution revenue pursuant to EIMA, which became effective in the fourth quarter of 2011.

Operating and maintenance expense increased by $596 million in 2011 primarily as a result of increased labor, other benefits, contracting and materials expenses of $241 million, including Exelon Wind, $88 million of costs related to the acquisitions of Wolf Hollow, Antelope Valley and the proposed merger with Constellation and a $74 million increase in nuclear refueling outage costs, including the co-owned Salem plant. Exelon's results were also affected by a $37 million increase in uncollectible accounts expense at ComEd, principally due to the approval of the recovery rider mechanism by the ICC in 2010. The increase was also attributable to higher storm costs in the ComEd and PECO service territories of $70 million and $13 million, respectively, which were partially offset at ComEd by a credit of $55 million, net of amortization, for the allowed recovery of certain 2011 storm costs pursuant to EIMA. These costs were partially offset by one-time net benefits of $32 million to re-establish plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan pursuant to the 2010 ComEd Rate Case order recorded in the second quarter of 2011.

Depreciation and amortization expense decreased by $740 million primarily due to a decrease in CTC amortization expense at PECO of $885 million resulting from the end of the transition period on December 31, 2010, partially offset by increased depreciation expense primarily due to additional plant placed in service and the acquisition of Exelon Wind.

Exelon's results were favorably impacted by decreased interest expense of $91 million primarily due to the impact of the 2010 remeasurement of uncertain income tax positions related to the 1999 sale of ComEd's fossil generating assets and CTCs collected by PECO, which resulted in interest expense of $59 million and $36 million, respectively, in 2010. In addition, in 2011, Exelon recorded interest income and tax benefits of $46 million, net of tax including the impact on the manufacturer's deduction, due to the 2011 NDT fund special transfer tax deduction. The decrease in interest expense was partially offset by higher interest expense at Generation and ComEd due to higher outstanding debt balances. Exelon's results were also significantly affected by unrealized losses on NDT funds of $4 million in 2011 (compared to unrealized gains of $104 million in 2010) for Non-Regulatory Agreement Units as a result of unfavorable market performance.

Exelon's results for the year ended December 31, 2011 were favorably impacted by certain prior year income tax-related matters. In 2010, Exelon recorded a $65 million (after-tax) charge to income tax expense as a result of health care legislation passed in March 2010 that includes a provision that reduces the deductibility of retiree prescription drug benefits for Federal income tax purposes. This amount was partially offset by a non-cash charge of $29 million (after-tax) recorded at Exelon in 2011 for the remeasurement of deferred taxes at higher corporate tax rates pursuant to the Illinois tax rate change legislation.

For further detail regarding the financial results for the years ended December 31, 2011 and 2010, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

***Adjusted (non-GAAP) Operating Earnings.*** Exelon's adjusted (non-GAAP) operating earnings for the year ended December 31, 2011 were $2,763 million, or $4.16 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,689 million, or $4.06 per diluted share, for the same period in 2010. In addition to net income, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the year ended December 31, 2011 as compared to 2010:

| | December 31, | | | |
|---|---|---|---|---|
| | 2011 | | 2010 | |
| **(All amounts after tax; in millions, except per share amounts)** | | **Earnings per Diluted Share** | | **Earnings per Diluted Share** |
| **Net Income** | $2,495 | $ 3.75 | $2,563 | $ 3.87 |
| Mark-to-Market Impact of Economic Hedging Activities [(a)] | 174 | 0.27 | (52) | (0.08) |
| Unrealized (Gains) Losses Related to NDT Fund Investments [(b)] | 1 | — | (52) | (0.08) |
| Retirement of Fossil Generating Units [(c)] | 33 | 0.05 | 50 | 0.08 |
| Asset Retirement Obligation Updates [(d)] | 16 | 0.02 | (7) | (0.01) |
| Constellation Acquisition Costs [(e)] | 46 | 0.07 | — | — |
| Other Acquisition Costs [(f)] | 5 | 0.01 | 7 | 0.01 |
| Non-Cash Charge Resulting From Illinois Tax Rate Change Legislation [(g)] | 29 | 0.04 | — | — |
| Wolf Hollow Acquisition [(h)] | (23) | (0.03) | — | — |
| Recovery of Costs Pursuant to Distribution Rate Case Order [(i)] | (17) | (0.03) | — | — |
| Non-Cash Remeasurement of Deferred Income Taxes [(j)] | 4 | 0.01 | — | — |
| Illinois Settlement Legislation [(k)] | — | — | 13 | 0.02 |
| Impairment of Certain Emissions Allowances [(l)] | — | — | 35 | 0.05 |
| City of Chicago Settlement with ComEd [(m)] | — | — | 2 | — |
| Non-Cash Charge Resulting From Health Care Legislation [(n)] | — | — | 65 | 0.10 |
| Non-Cash Remeasurement of Income Tax Uncertainties and Reassessment of State Deferred Income Taxes [(o)] | — | — | 65 | 0.10 |
| **Adjusted (non-GAAP) Operating Earnings** | $2,763 | $ 4.16 | $2,689 | $ 4.06 |

(a) Reflects the impact of (gains) losses for the years ended December 31, 2011 and 2010, respectively, on Generation's economic hedging activities (net of taxes $114 million and $(34) million, respectively). See Note 9 of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of unrealized (gains) losses for the years ended December 31, 2011 and 2010, respectively, on Generation's NDT fund investments for Non-Regulatory Agreement Units (net of taxes of $(3) million and $(50) million, respectively). See Note 12 of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Primarily reflects accelerated depreciation expense for the years ended December 31, 2011 and 2010 (net of taxes of $21 million and $32 million, respectively) associated with the planned retirement of four generating units, two of which were retired on May 31, 2011. Beginning June 1, 2011, reflects the net loss attributable to the remaining two units, which includes compensation for operating the units past their planned May 31, 2011 retirement date under a FERC-approved reliability-must-run rate schedule. See Note 14 of the Combined Notes to Consolidated Financial Statements and "Results of Operations – Generation" for additional detail related to the generating unit retirements.

(d) Reflects the income statement impact for the years ended December 31, 2011 and 2010, respectively, primarily related to the reduction in PECO's asset retirement obligation in 2011 (net of taxes of $(1) million), an increase in Generation's Zion's decommissioning obligation for spent nuclear fuel at Zion in 2011 (net of taxes of $11 million) and the reduction in the asset retirement obligations at ComEd and PECO in 2010 (net of taxes of $(4) million).

(e) Reflects certain costs incurred in the year ended December 31, 2011 associated with Exelon's proposed acquisition of Constellation (net of taxes of $31 million). See Note 3 of the Combined Notes to the Consolidated Financial Statements for additional information.

(f) Reflects certain costs incurred in the years ended December 31, 2011 and 2010, respectively, associated with Exelon's acquisitions of Exelon Wind in 2010 (net of taxes of $4 million) and Antelope Valley in 2011 (net of taxes of $3 million). See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

(g) Reflects a one-time, non-cash charge to remeasure deferred taxes at higher corporate tax rates pursuant to the Illinois tax rate change legislation. See Note 11 of the Combined Notes to the Consolidated Financial Statements for additional detail related to the impact of the Illinois tax rate change legislation.

(h) Reflects a non-cash bargain purchase gain (negative goodwill) for the year ended December 31, 2011 in connection with the acquisition of Wolf Hollow, net of acquisition costs (net of taxes of $15 million). See Note 3 of the Combined Notes to the Consolidated Financial Statements for additional information.

(i) Reflects a one-time benefit in 2011 to recover previously incurred costs as a result of the May 2011 ICC rate order (net of taxes of $5 million). See Note 2 of the Combined Notes to the Consolidated Financial Statements for additional information.

(j) Reflects the non-cash impacts of the annual remeasurement of state deferred income taxes to reflect revised estimates of state apportionments. See Note 11 of the Combined Notes to the Consolidated Financial Statements for additional detail related to the impact of the Illinois tax rate change legislation.

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

(l) Reflects the impairment of certain SO2 emissions allowances in 2010 as a result of declining market prices following the release of the EPA's proposed Transport Rule (net of taxes of $22 million). See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.

(m) Reflects costs associated with ComEd's 2007 settlement agreement with the City of Chicago (net of taxes of $1).

(n) Reflects a non-cash charge to income taxes related to the passage of Federal health care legislation, which includes a provision that reduces the deductibility, for Federal income tax purposes, of retiree prescription drug benefits for Federal income tax purposes to the extent they are reimbursed under Medicare Part D. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional detail related to the impact of the health care legislation.

(o) Reflects the impact of remeasurements of income tax uncertainties. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional detail.

**Outlook for 2012 and Beyond.**

***Acquisitions***

***Proposed Merger with Constellation.*** On April 28, 2011, Exelon and Constellation announced that they signed an agreement and plan of merger to combine the two companies in a stock-for-stock transaction. Under the merger agreement, Constellation's shareholders will receive 0.930 shares of Exelon common stock in exchange for each share of Constellation common stock. Based on Exelon's closing share price on April 27, 2011, Constellation shareholders would receive $7.9 billion in total equity value. The resulting company will retain the Exelon name and be headquartered in Chicago. The transaction requires approval by the shareholders of both Exelon and Constellation. Completion of the transaction is also conditioned upon review of the transaction by the U.S. Department of Justice (DOJ) and approval by the FERC, NRC, Maryland Public Service Commission (MDPSC), the New York Public Service Commission (NYPSC), the Public Utility Commission of Texas (PUCT), and other state and federal regulatory bodies. As of February 9, 2012, Exelon and Constellation have received approval of the transaction from the shareholders of Exelon and Constellation, DOJ, PUCT and the NYPSC. Exelon and Constellation are awaiting final approval of the transaction from the MDPSC, FERC and NRC.

On January 30, 2012, FERC published a notice on its website regarding a non-public investigation of certain of Constellation's power trading activities in and around the New York ISO from September 2007 through December 2008. Exelon continues to evaluate the matter in order to make an assessment regarding (1) the likely outcome of the investigation and (2) whether the ultimate resolution of the investigation will be material to the results of operations, cash flows, or financial condition of Constellation before the merger or Exelon after the merger. Absent any delay in the FERC approval process, the companies anticipate closing the transaction in the first quarter of 2012.

Associated with certain of the regulatory approvals required for the merger, the companies have proposed to divest three Constellation generating stations located in PJM, which is the only market where there is a material overlap of generation owned by both companies. These stations, Brandon Shores and H.A. Wagner in Anne Arundel County, Maryland, and C.P. Crane in Baltimore County, Maryland, include base-load, coal-fired generation units plus associated gas/oil units located at the same sites, and total 2,648 MW of generation capacity. In October 2011, Exelon and Constellation reached a settlement with the PJM Independent Market Monitor, who had previously raised market power concerns regarding the merger. The settlement contains a number of commitments by the merged company, including limiting the universe of potential buyers of the divested assets to entities without significant market shares in the relevant PJM markets. The settlement also includes assurances about how the merged company will bid its units into the PJM markets. The proposed divestiture and the settlement with the PJM Market Monitor were filed with FERC and the MDPSC and are included in its decision to issue a final order approving the merger.

In December 2011, Exelon and Constellation reached a settlement with the State of Maryland and the City of Baltimore and other interested parties in connection with the regulatory proceedings pending before the MDPSC. As part of this settlement and the application for approval of the merger by MDPSC, Exelon and Constellation have proposed a package of benefits to BGE customers, the City of Baltimore and the state of Maryland, which results in a direct investment in the state of Maryland of more than $1 billion. This investment includes capital projects including development of new renewable and gas-fired generation in Maryland, representing a substantial portion of the investment.

In addition, in January 2012, Exelon and Constellation reached an agreement with Electricite de France (EDF) under which EDF has withdrawn its opposition to the Exelon-Constellation merger. The terms address Constellation Energy Nuclear Group (CENG), a joint venture between Constellation and EDF that owns and operates three nuclear facilities with five generating units in Maryland and New York. The agreement reaffirms the terms of the joint venture. The agreement did not include any exchange of monetary consideration and Exelon does not expect the agreement will have a material effect on Exelon and Generation's future results of operations, financial position and cash flows.

Exelon was named in suits filed in the Circuit Court of Baltimore City, Maryland alleging that individual directors of Constellation breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. Similar suits were also filed in the United States District Court for the District of Maryland. The suits sought to enjoin a Constellation shareholder vote on the proposed merger until all material information is disclosed and sought rescission of the proposed merger. During the third quarter, the parties to the suits reached an agreement in principle to settle the suits through additional disclosures to Constellation shareholders. The settlement is subject to court approval.

Through December 31, 2011, Exelon has incurred approximately $77 million of expense associated with the transaction, primarily related to fees incurred as part of the acquisition. Exelon currently estimates the total costs directly related to closing the transaction will be approximately $150 million, which include financial advisor, consultant, legal and SEC registration fees. In addition, Exelon estimates approximately $500 million of additional integration costs, primarily to be incurred in 2012 and 2013. Such costs are expected to be partially offset by projected merger-related synergies in 2012 and fully offset in 2013 and beyond. Under the merger agreement, in the event Exelon or Constellation terminates the merger agreement to accept a superior proposal, or under certain other circumstances, Exelon or Constellation, as applicable, would be required to pay a termination fee of $800 million in the case of a termination fee payable by Exelon to Constellation or a termination fee of $200 million in the case of a termination fee payable by Constellation to Exelon. The acquisition is anticipated to be break-even to Exelon's adjusted earnings in 2012 and is expected to be accretive to earnings in 2013.

***Acquisition of Antelope Valley Solar Ranch One.*** On September 30, 2011, Generation announced its acquisition of Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, which developed and will build, operate and maintain the project. Construction has started, with the first portion of the site expected to come online in late 2012 and full operation planned for late 2013. When fully operational, Antelope Valley will be one of the largest PV solar projects in the world, with approximately 3.8 million solar panels generating enough clean, renewable electricity to power the equivalent of 75,000 homes on average per year. The acquisition builds on the Exelon commitment to clean energy as part of Exelon 2020, a business and environmental strategy to eliminate the equivalent of Exelon's 2001 carbon footprint. The project has a 25-year PPA, approved by the California Public Utilities Commission, with Pacific Gas & Electric Company for the full output of the plant. Exelon expects to invest up to $713 million in equity in the project through 2013. The DOE's Loan Programs Office issued a loan guarantee of up to $646 million to support project financing for Antelope Valley. Exelon expects the total investment of up to $1.36 billion to be accretive to earnings beginning in 2013 and cash flow accretive starting in 2013. The project is value accretive, and will have stable earnings and cash flow profiles due to the PPA.

***Acquisition of Wolf Hollow Generating Station.*** On August 24, 2011, Generation completed the acquisition of the equity interest of Wolf Hollow, LLC (Wolf Hollow), a combined-cycle natural gas-fired power plant in north Texas, pursuant to which Generation added 720 MWs of capacity within the ERCOT power market. The acquisition builds on the Exelon commitment to clean energy as part of Exelon 2020. Generation recognized a $36 million bargain purchase gain (i.e., negative goodwill) as part of the transaction. The gain was included within other, net in Exelon's Consolidated Statements of Operations and Comprehensive Income. In connection with the acquisition, Generation terminated and settled its long-term PPA with Wolf Hollow; resulting in a gain of approximately $6 million, which is included within Operating Revenues (Other Revenue) in Exelon's Consolidated Statements of Operations and Comprehensive Income. In addition to eliminating the existing power purchase agreement, Exelon expects the transaction will be accretive to free cash flow beginning in 2012. The transaction also creates long-term value for Exelon by adding an efficient combined-cycle natural gas-fired plant to Exelon's fleet in ERCOT.

***Acquisition of Exelon Wind.*** In December 2010, Generation acquired all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind), a leading operator and developer of wind power, for approximately $893 million in cash. Generation acquired 735 MWs of installed, operating wind capacity located in eight states. Approximately 75% of the operating portfolio's expected output is already sold under long-term power purchase arrangements. Additionally, Generation will pay up to $40 million related to three projects with a capacity of 230 MWs which are currently in advanced stages of development, contingent upon meeting certain contractual commitments related to the commencement of construction of each project. This contingent consideration was valued at $32 million, of which approximately $16 million was paid during 2011. As a result, total consideration recorded for the Exelon Wind acquisition was $925 million. The acquisition currently provides incremental earnings, provides cash flows starting in 2013 and is a key part of Exelon 2020.

### *Japan Earthquake and Tsunami and the Industry's Response*

On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co.

Generation believes its nuclear generating facilities do not have the same operating risks as the Fukushima Daiichi plant because they meet the NRC's requirement that specifies all plants must be able to withstand the most severe natural phenomena historically reported for each plant's surrounding area, with a significant margin for uncertainty. In addition, Generation's plants are not located in significant earthquake zones or in regions where tsunamis are a threat. Generation believes its nuclear generating facilities are able to shut down safely and keep the fuel cooled through multiple redundant systems specifically designed to maintain electric power when electricity is lost from the grid. Further, Generation's nuclear generating facilities also undergo frequent scenario drills to ensure the proper function of the redundant safety protocols. Prior to the earthquake and tsunami in Japan, the NRC and licensees had been evaluating seismic risk in relation to the design basis of plants and whether additional regulatory action was required. In December 2011, the Commission directed the NRC staff to inform the Commissioners' assistants of its plans for closing out the seismic risk issues previously under review and addressing the interdependency between those issues and the seismic risk recommendations identified in the report of the NRC Near-Term Task Force on the Fukushima Daiichi Accident (Task Force) (discussed in more detail below). In January 2012, the NRC released an updated seismic risk model that plant operators must use in performing the seismic reevaluations recommended by the Task Force.

The NRC has received various petitions from individuals and citizen groups regarding Mark I and II containment systems and requesting that actions be taken in response to the events in Japan. The NRC has either denied the petitions or acknowledged acceptance of the petitions as the subject of ongoing NRC staff and/or Task Force reviews of the Fukushima Daiichi accident. These petitions could affect Dresden, Quad Cities, Oyster Creek and Peach Bottom stations (Mark I containment designs) and LaSalle and Limerick stations (Mark II containment designs).

On July 12, 2011, the NRC Task Force issued a report of its review of the accident, including recommendations for future regulatory action by the NRC to be taken in the near and longer term. The report is the first step in a systematic review that the NRC is conducting. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The report includes recommendations to the NRC in three primary areas: 1) the overall structure and philosophy of the NRC's regulatory framework; 2) specific design requirements for the nuclear units; and 3) emergency preparedness. During the fourth quarter of 2011, as directed by the Commission, the NRC staff issued its recommendations for prioritizing and implementing the Task Force recommendations and an implementation schedule. Of note, the NRC staff confirmed the Task Force's conclusions that none of the findings arising from the Task Force review presented an imminent risk to public health and safety. The NRC staff evaluated the potential and relative safety enhancements to be realized from each recommendation and, based on that evaluation, classified the recommendations as falling in three tiers: Tier 1, reflecting near term recommendations to be initiated without unnecessary delay; Tier 2, reflecting recommendations to be deferred pending receipt of additional information, completion of Tier 1 activities, or the availability of resources; and Tier 3, reflecting recommendations to be deferred pending an additional nine month review by the NRC staff. The near term recommendations falling in Tier 1 address seismic and flooding risks, coping with extended loss of power in a station blackout, protecting and increasing the amount of backup equipment, reliable hardened vents for Mark I and Mark II containment, enhancing procedures to address severe accidents and emergency planning, and enhancing spent fuel instrumentation. As instructed by the Commission, the NRC staff also identified additional issues not considered by the Task Force that may, in the staff's assessment, warrant regulatory action. Among the additional issues identified are filtration of containment vents and the transfer of spent fuel to dry cask storage. The staff committed to provide an update on its evaluation of the additional issues within nine months. For each of the recommendations and additional issues, the NRC staff's proposed schedule provides for stakeholder input prior to taking regulatory action.

In December 2011, the Commission approved the staff's prioritization and implementation recommendations subject to a number of conditions. Specifically, among other things, the Commission advised the staff to give the highest priority to those activities that can achieve the greatest safety benefit and/or have the broadest applicability and to include filtration of containment vents with the Tier 1 review of Mark I and II containments, and encouraged the staff to create requirements based on a performance-based system which allows for flexible approaches and the ability to address a diverse range of site-specific circumstances and conditions and "strive to complete and implement the lessons learned from the Fukushima accident within five years – by 2016." The NRC and staff's next steps are to obtain stakeholder input and issue specific requirements associated with the prioritized recommendations. The requirements for the majority of the Tier 1 recommendations are anticipated to be received in the first quarter of 2012 with the requirements for the remaining Tier 1 recommendations following in 2014 and 2016.

Generation is assessing the impacts of the NRC staff's evaluations and the Commission's approval of the recommendations, both from an operational and a financial impact standpoint. Until the specific requirements for each recommendation are established after obtaining stakeholder input, Generation is unable to determine with specificity the impact the recommendations may have on its nuclear units. However, Generation will continue to engage in nuclear industry assessments and actions.

The Task Force's report did not recommend any changes to the existing nuclear licensing process in the United States or changes in the storage of spent nuclear fuel within the plant's spent nuclear fuel pools. However, as noted above, the NRC staff identified the transfer of spent fuel to dry cask storage as an additional issue to be evaluated by the NRC staff over a nine month period. The facts surrounding what happened at the Fukushima Daiichi Nuclear Power Station, including the nature and extent of damages, the underlying causes of the situation, and the degree to which these factors apply to Generation's nuclear generating facilities, are still under investigation, and will be for some time. Although the NRC staff's reports to the Commission and the Commission's approval of the recommendations and instructions to the NRC staff provide clarity with respect to issues that will be subject to regulatory review and action, the nature and degree of actions that will be required of Generation are still unknown and will be determined through the regulatory process after allowing for stakeholder input. As a result, Exelon and Generation are unable to conclude, at this time, to what extent any actions to comply with the requirements will impact their future results of operations, financial positions and cash flows. See ITEM 1A. Risk Factors of Exelon's 2011 Form 10-K, for further discussion of the risk factors.

Since the events in Japan took place, Generation has continued to work with regulators and nuclear industry organizations to understand the events in Japan and apply lessons learned. The nuclear industry has already taken specific steps to respond. Generation has completed actions requested by the Institute of Nuclear Power Operations (INPO), which included tests that verified its emergency equipment is available and functional, walk-downs on its procedures related to critical safety equipment, confirmation of event response procedures and readiness to protect the spent fuel pool, and verification of current qualifications of operators and support staff needed to implement the procedures. Generation has been addressing additional actions requested by INPO for improving and maintaining core and spent fuel pool cooling during an extended loss of power for at least 24 hours.

Generation's plan for increasing the output through uprates of its nuclear generating stations has not changed as a result of the situation in Japan. However, Generation will continue to monitor NRC directives and guidance that may impact the uprates and, as it has in the past, evaluate each project at the appropriate time and cancel or defer any uprate project that is not considered economical, whether due to energy prices, potential increased regulation, or other factors.

***Economic and Market Conditions***

Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular, the prices of natural gas and coal, which drive the wholesale market prices that Generation's power plants can obtain for their output, (2) the rate of expansion of subsidized low carbon generation such as wind energy in the markets in which Generation's output is sold, (3) the impacts on energy demand of factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) regulatory and legislative actions, such as the U.S. EPA's Cross-State Air Pollution Rule (CSAPR) and U.S. EPA's Mercury and Air Toxics Standards (MATS). See *Environmental Matters* section below for further detail on CSAPR and the MATS.

The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale power prices, which results in a reduction in Exelon's revenues.

The market price for electricity is also affected by changes in the demand for electricity. Poor economic conditions, milder than normal weather and the growth of energy efficiency and demand response programs can depress demand. The result is that higher-cost generating resources do not run as frequently, putting downward pressure on market prices for electricity and/or capacity. The continued sluggish economy in the United States has led to a decline in demand for electricity. ComEd is projecting load demand to remain essentially flat in 2012 compared to 2011, while PECO is projecting a decline of 5.4% in 2012 compared to 2011 primarily due to the anticipated closing of three oil refineries in its service territory.

Since September 30, 2011, natural gas prices for 2013 and 2014 have declined significantly; reflecting strong natural gas production and significantly warmer than normal weather so far this winter, as well as generally lowered expectations for gas demand and economic growth rates. Wholesale power prices have likewise decreased in response in part to the lower gas prices, and to the late December 2011 judicial stay of the EPA's CSAPR and various other market factors.

Exelon has a policy to hedge commodity risk on a ratable basis over three-year periods, which is intended to reduce the near-term financial impact of market price volatility. As of December 31, 2011, the percentage of expected generation hedged was 88%-91%, 61%-64% and 32%-35% for 2012, 2013 and 2014, respectively.

Exelon also has exposure to worldwide financial markets. The ongoing European debt crisis has contributed to the instability in global credit markets. Further disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2011, approximately 35%, or $2.7 billion, of Exelon's available credit facilities were with European banks. The credit facilities include $7.7 billion in aggregate total commitments of which $6.8 billion was available as of December 31, 2011. There were no borrowings under Exelon's credit facilities as of December 31, 2011. See Note 10 of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

Exelon routinely reviews its hedging policy, operating and capital costs, capital spending plans, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices, and the impacts of hypothetical credit downgrades. Based on the results of these assessments, Exelon management believes it is able to respond to changing market conditions in a manner that ensures reliable and safe service for our customers and sufficient liquidity to operate our businesses.

***Hedging Strategy.*** Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2012 and 2013. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. Generation currently hedges commodity risk on a ratable basis over the three years leading to the spot market. As of December 31, 2011, the percentage of expected generation hedged was 88%-91%, 61%-64% and 32%-35% for 2012, 2013 and 2014, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include cash flow hedges, other derivatives and certain non-derivative contracts including sales to ComEd and PECO to serve their retail load. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well. The expiration of the PPA with PECO at the end of 2010 has resulted in increases in margins earned by Generation in 2011 for the portion of Generation's electricity portfolio previously sold to PECO under the PPA; however the ultimate impact of entering into new power supply contracts under Generation's three-year ratable hedging program to replace the PPA will depend on a number of factors, including future wholesale market prices, capacity markets, energy demand and the effects of any new applicable Pennsylvania laws and or rules and regulations promulgated by the PAPUC.

Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 55% of Generation's uranium concentrate requirements from 2012 through 2016 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position. Generation uses long-term contracts and financial instruments such as over-the-counter and exchange-traded instruments to mitigate price risk associated with certain commodity price exposures. Both ComEd and PECO mitigate exposure as a result of the regulatory mechanisms that allow them to recover procurement costs from retail customers.

***New Growth Opportunities***

***Nuclear Uprate Program.*** Generation has announced a series of planned power uprates across its nuclear fleet that would result in between 1,175 and 1,300 MWs at an overnight cost of approximately $3.3 billion in 2011 dollars, of which approximately $800 million has been spent through December 31, 2011. Overnight costs do not include financing costs or cost escalation. Using proven technologies, the projects take advantage of new production and measurement technologies, new materials and learning from a half-century of nuclear power operations. Uprate projects, representing approximately 75% of the planned uprate MWs, are underway at the Limerick, TMI and Peach Bottom nuclear stations in Pennsylvania and the Byron, Braidwood, Dresden, LaSalle and Quad Cities plants in Illinois. The remaining uprate MWs will come from additional projects across Generation's nuclear fleet beginning in 2012 and ending in 2017. At 1,300 nuclear-generated MWs, the uprates would displace 6 million metric tons of carbon emissions annually that would otherwise come from burning fossil fuels. The uprates are being undertaken pursuant to an organized, strategically sequenced implementation plan. The implementation effort includes a periodic review and refinement of the project in light of changing market conditions. The amount of expenditures to implement the plan ultimately will depend on economic and policy developments, and will be made on a project-by-project basis in accordance with Exelon's normal project evaluation standards. The ability to implement several projects requires the successful resolution of various technical issues. The resolution of these issues may affect the timing and amount of the power increases associated with the power uprate initiative. Through December 31, 2011, Generation has added 240 MWs of nuclear generation through its uprate program.

***Transmission Development Project.*** Exelon, Electric Transmission America, LLC (ETA) and AEP Transmission Holding Company, LLC (AEP) are working collaboratively to develop a 420-mile extra high-voltage transmission project from the western Ohio border through Indiana to the northern portion of Illinois. Referred to as the Reliability Interregional Transmission Extension (RITE) Line project, the project is expected to strengthen the high-voltage transmission system and improve overall system reliability. RITELine Illinois, LLC (RITELine Illinois) and RITELine Indiana, LLC (RITELine Indiana) have been formed as project companies to develop and own the project. RITELine Illinois will own the transmission assets located in Illinois and is owned 75% by ComEd and 25% by RITELine Transmission Development Company, LLC (RTD). RITELine Indiana will own the transmission assets located in Indiana and is owned by ETA (37.5%), AEP (37.5%) and RTD (25%). Exelon Transmission Company, LLC and ETA each own 50% of RTD. During December 2011, RITELine Illinois, RITELine Indiana and RTD received capital contributions of $2 million, $2 million and $1 million respectively. Funding was provided to each company based upon the aforementioned ownership structure. The total cost of the RITE Line project is expected to be approximately $1.6 billion, with the Illinois portion of the line expected to cost approximately $1.2 billion. The ultimate cost of the line will depend on a number of factors, including RTO requirements, state siting requirements, routing of the line, and equipment and commodity costs. The project will be built in stages over three to four years, likely between 2015 and 2018, and is subject to FERC, PJM and state approvals. Significant funding for this project is not expected to occur until 2014, with most of the funding expected in 2015-2017.

On July 18, 2011, RITELine Illinois and RITELine Indiana filed at FERC for incentive rates and a formula rate for the RITE Line project. On October 14, 2011, FERC issued an order on the incentive and formula rate filing. The order grants a base rate of return on common equity of 9.93%, plus a 50 basis point adder for the project being in a RTO and a 100 basis point adder for the risks and challenges of the project, resulting in a total rate of return on common equity of 11.43%. The order grants a hypothetical capital structure of 45% debt and 55% equity until any part of the project enters commercial operations. The order also grants 100% recovery for construction work in progress, 100% recovery for abandonment, if the line is abandoned through no fault of the RITELine developers, and the ability to treat pre-construction costs as a regulatory asset. All incentives, including the abandonment incentive, are contingent on inclusion of the project in the PJM RTEP. The RITELine companies filed for rehearing on several rate of return on common equity issues and argued that the right to collect abandoned costs should not be subject to the project being included in the RTEP. The RITELine companies also made a compliance filing as called for in the October 14, 2011 Order.

***Utility Infrastructure.*** During the fourth quarter of 2011, EIMA was enacted in Illinois, which provides for ComEd to invest an additional $2.6 billion over a ten-year period to modernize Illinois' electric utility infrastructure and for greater certainty related to the recovery of costs by a utility through a pre-established distribution formula rate tariff.

In 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, representing an investment of up to a total of $650 million, including its $200 million SGIG, on its smart grid and smart meter infrastructure. See the *Regulatory and Legislative Matters* section below and Note 2 of the Combined Notes to Consolidated Financial Statements for additional information on the utility infrastructure projects.

### *Liquidity and Cost Management*

***Pension Plan Funding.*** In January 2011, Exelon contributed $2.1 billion to its pension plans which, along with other factors, increased the funded status of the Exelon pension plans to 83% at December 31, 2011 from 71% at December 31, 2010. This contribution creates flexibility around the timing of future expected minimum contributions, decreases future pension costs, and allows Exelon to further pursue its liability hedge strategy in order to reduce the volatility of its pension assets relative to its pension liabilities.

***Financing Activities.*** On January 18, 2011, ComEd issued $600 million of 1.625% First Mortgage Bonds due January 15, 2014. The net proceeds of the bonds were used as an interim source of liquidity for the January 2011 contribution to Exelon-sponsored pension plans in which ComEd participates. ComEd anticipates receiving tax refunds as a result of both the pension contribution and the Tax Relief Act of 2010 allowing for 100% bonus depreciation deductions in 2011 and 2012. As a result, the immediate use of the net proceeds to fund the planned contribution will allow those future cash receipts to be available to fund capital investment and for general corporate purposes.

On September 7, 2011, ComEd issued $250 million of 1.95% First Mortgage Bonds due September 1, 2016 and $350 million of 3.40% First Mortgage Bonds due September 1, 2021. The majority of the net proceeds of the bonds was used to refinance $191 million of ComEd's variable rate tax-exempt bonds on October 12, 2011 and $345 million of ComEd's 5.40% First Mortgage Bonds due December 15, 2011. The remainder of the net proceeds were used to fund other general corporate purposes.

***Credit Facilities.*** On March 23, 2011, Exelon Corporate, Generation and PECO replaced their unsecured revolving credit facilities with new facilities with aggregate bank commitments of $500 million, $5.3 billion and $600 million, respectively. Although the covenants are largely the same as the prior facilities, the new facilities have higher borrowing costs, reflecting current market pricing. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information regarding those costs.

ComEd's $1.0 billion unsecured revolving credit facility expires on March 25, 2013 unless extended in accordance with terms. ComEd plans to renew or replace the credit facility in 2012. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information regarding the credit facility terms.

On October 21, 2011, Generation, ComEd and PECO replaced their expiring minority and community bank credit facility agreements with new minority and community bank credit facility agreements in the amounts of $50 million, $34 million and $34 million, respectively. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information regarding the credit facilities.

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

### *Environmental Matters*

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

### *Environmental Legislative and Regulatory Developments*

Exelon supports the promulgation of environmental regulation by the U.S. EPA, including air, water and waste controls for electric generating units. See discussion below for further details. The air and waste regulations will have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and will likely result in the retirement of older, marginal facilities. Due to its low emission generation portfolio, Generation will not be significantly directly affected by these regulations, representing a competitive advantage for Generation relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. House of Representatives that would prohibit or impede the U.S. EPA's rulemaking efforts. The timing of the consideration of such legislation is unknown.

***Air.*** Beginning with the CSAPR, the air requirements are expected to be implemented through a series of increasingly stringent regulations relating to conventional air pollutants (e.g., $NO_x$, $SO_2$ and particulate matter) as well as HAPs (e.g., acid gases, mercury and other heavy metals). It is expected that the U.S. EPA will complete a review of NAAQS in the 2012 – 2013 timeframe for particulate matter, nitrogen dioxide, sulfur dioxide and lead. This review will likely result in more stringent emissions limits on fossil-fuel fired electric generating stations. There is opposition among fossil fuel-fuel fired generation owners to the potential stringency and timing of these air regulations, and the House Commerce and Energy Committee and several of its subcommittees have held a number of hearings on these issues.

On July 7, 2011, the U.S. EPA published a final rule known as CSAPR. The CSAPR requires 27 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states. On October 14, 2011, the EPA proposed for public comment certain technical corrections to CSAPR, including correction of data errors in determining generation unit allowances and state allowance budgets. These corrections will increase the number of emission allowances available under the CSAPR. In addition, the proposal defers until

2014 penalties that will involve surrender of additional allowances should states not meet certain levels of emission reductions. This deferral is intended to increase the liquidity of allowances during the initial years of transition from CAIR to CSAPR. Upon preliminary review, it is expected that implementation of the CSAPR will modestly increase power prices over the long term, which would result in a net benefit to Generation's results of operations and cash flows.

Several entities challenged the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit, and requested a stay of the rule pending the Court's consideration of the matter on the merits. On December 30, 2011, the Court granted a stay and directed the U.S. EPA to continue the administration of CAIR in the interim. The Court ordered an expedited briefing schedule that requires that final briefs be submitted by March 16, 2012, and scheduled oral argument for April 13, 2012. It is unknown when the Court will issue its decision on the merits. Exelon believes that CSAPR is a valid exercise of the U.S. EPA's authority and discretion under the CAA. Exelon has received permission from the Court to intervene in support of CSAPR and in opposition to the stay.

On December 16, 2011, the U.S. EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the new source performance standards for electric generating units. The final rule, known as the Mercury and Air Toxics (MATS) rule, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that owners of smaller, older, uncontrolled coal units will retire the units rather than make these investments. Coal units with existing controls that do not meet the MATS rule may need to upgrade existing controls or add new controls to comply. Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS by January 1, 2015. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units.

The cumulative impact of these regulations could be to require power plant operators to expend significant capital to install pollution control technologies, including wet flue gas desulfurization technology for $SO_2$ and acid gases, and selective catalytic reduction technology for $NO_x$.

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act, including permitting requirements under the PSD and Title V operating permit sections of the Clean Air Act for new and modified stationary sources that became effective on January 2, 2011.

Exelon supports comprehensive climate change legislation by the U.S Congress, including a mandatory, economy-wide cap-and-trade program for GHG emissions that balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions. Several bills containing provisions for legislation of GHG emissions were introduced in Congress from January 2009 through January 2011, but none were passed by both houses of Congress.

***Water.*** Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. Regulations adopted by the U.S. EPA in 2004 applicable to large electric generating stations were withdrawn in 2007 following a decision by the U.S. Second Circuit Court of Appeals that invalidated many of the rule's significant provisions and remanded the rule to the EPA for further consideration and revision. On March 28, 2011, the EPA issued a proposed rule, and is required under a Settlement Agreement to issue a final rule by July 27, 2012. The proposed rule does not require closed cycle cooling (e.g., cooling towers) as the best technology available, and also provides some flexibility in the use of cost-benefit considerations and site-specific factors. The proposed rule affords the state permitting agency wide discretion to determine the best technology available, which, depending on the site characteristics, could include closed cycle cooling, advanced screen technology at the intake, or retention of the current technology.

It is unknown at this time whether the final regulations or permit will require closed-cycle cooling at Salem. In addition, the economic viability of Generation's other power generation facilities without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Should the final rule not require the installation of cooling towers, and retain the flexibility afforded the state permitting agencies in applying a cost – benefit test and to consider site-specific factors, the impact of the rule would be minimized even though the costs of compliance could be material to Generation.

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

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

***Regulatory and Legislative Matters***

***Legislation to Modernize Electric Utility Infrastructure and to Update Illinois Ratemaking Process.*** On October 26, 2011, the Illinois General Assembly overrode the Governor's veto of the Illinois Energy Infrastructure Modernization Act (SB 1652), which became effective immediately. The Illinois General Assembly also passed House Bill 3036 (the Trailer Bill), which modifies and supplements SB 1652. The Governor signed the Trailer Bill into law on December 30, 2011. The combined legislation (EIMA) provides for substantial capital investment over a ten-year period to modernize Illinois' electric utility infrastructure and for greater certainty related to the recovery of costs by a utility through a pre-established formula rate tariff. Under the terms of EIMA, ComEd's target rate of return on common equity is subject to reduction if ComEd does not deliver the reliability and customer service benefits, as defined, it has committed to over the ten-year life of the investment program. In addition, ComEd will make contributions to fund customer assistance programs and for a new Science and Technology Innovation Trust fund as a result of the combined legislation. The legislation also contains a provision for the IPA to complete a procurement event for energy and REC requirements for the June 2013 through May 2017 period In order to protect consumers, EIMA contains several restrictions and potential criteria for the program to terminate prematurely, ending ComEd's investment commitment and the performance-based distribution formula rates.

On November 8, 2011, ComEd filed its initial formula rate tariff and associated testimony based on 2010 costs and 2011 plant additions. The ICC will review ComEd's rate filing to evaluate the prudence and reasonableness of the costs and issue its order in a shortened proceeding. This rate will take effect within 30 days after the ICC order, which must be issued by May 31, 2012.

The legislation provides for an annual reconciliation of the revenue requirement in effect to reflect the actual costs incurred in a given year. ComEd will make its initial reconciliation filing in May 2012, and the rate adjustments necessary to reconcile 2011 revenues to ComEd's actual 2011 costs incurred will take effect in January 2013 after the ICC's review. As of December 31, 2011, ComEd recorded an estimated regulatory asset of approximately $84 million and an offsetting increase in revenues for the 2011 reconciliation and net decrease in operating and maintenance expense for the deferral of certain storm costs of $29 million and $55 million, respectively. This regulatory asset represents ComEd's best estimate of the probable increase in distribution rates expected to be approved by the ICC to provide ComEd recovery of all prudently and reasonably incurred costs in 2011 and an earned rate of return on common equity, as defined in the legislation, for 2011. As the ICC proceeding to review ComEd's initially filed formula rate tariff progresses through May 2012, ComEd will adjust the estimated regulatory asset recorded as of December 31, 2011, to reflect any revisions made to the proposed formula by the ICC. ComEd currently does not anticipate any such adjustments would be material to its overall results of operations, financial position or cash flows. The positive impact of the reconciliation mechanism on ComEd's 2011 pre-tax income was partially offset by the recognition of $15 million contribution to be made to the Science and Technology Innovation Trust fund discussed above. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

***Appeal of 2007 Illinois Electric Distribution Rate Case.*** On September 30, 2010, the Illinois Appellate Court (Court) issued a decision in the appeals related to the ICC's order in ComEd's 2007 electric distribution rate case (2007 Rate Case). That decision ruled against ComEd on the treatment of post-test year accumulated depreciation and the recovery of costs for an AMI/Customer Applications pilot program via a rider (Rider SMP). On January 25, 2011, ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court that was denied on March 30 2011. The ICC has initiated a proceeding on remand. ComEd expects that the ICC will issue a final order in early 2012. ComEd filed testimony that no refunds should be required in this proceeding and in the event of any refund, the maximum refund should be $30 million. On November 10, 2011, the ALJ issued a proposed order in the remand proceeding agreeing with ComEd that the ICC does not have the legal authority to order a refund; a refund may only be ordered by a court. The ALJ also concluded that, to the extent that a court orders a refund, it should be in the amount of $37 million, including interest. As of December 31, 2011, ComEd has recognized for accounting purposes its best estimate of any refund obligation, subject to reconciliation when the ICC issues a final order. ComEd does not believe any of its other riders are affected by the Court's ruling. See Note 2 of the Combined Notes to Consolidated Financial Statements for further details related to the Court's order.

***2010 Illinois Electric Distribution Rate Case.*** On May 24, 2011, the ICC issued an order in ComEd's 2010 electric delivery services rate case. ComEd requested an increase in the annual revenue requirement to allow ComEd to recover the costs of substantial investments made in its distribution system since its last rate filing in 2007. The requested increase also reflected increased costs, most notably pension and other postretirement employee benefits, since ComEd's rates were last determined.

The ICC order, which became effective on June 1, 2011, approved a $143 million increase to ComEd's annual delivery services revenue requirement, which is approximately 42% of the $343 million requested by ComEd in its reply brief on February 23, 2011. The approved rate of return on common equity is 10.50%. As a result of the order, ComEd recorded a one-time net benefit of approximately $58 million that includes the reestablishment of previously expensed plant balances, the establishment of new regulatory assets, and the reversal of certain reserves. The benefit is reflected as an increase to operating revenues and a reduction in operating and maintenance expense and income tax expense for the nine months ended September 30, 2011. The order has been appealed to the Court by several parties. ComEd cannot predict the results of these appeals. See Note 2 of the Combined Notes to Consolidated Financial Statements for further details related to the 2010 Rate Case.

***PECO's Default Service Provider Programs.*** Beginning in January 2011, PECO procured electric supply for default electric service customers through contracts executed through competitive procurements conducted in accordance with its DSP Program approved by the PAPUC in 2009. PECO will conduct three additional competitive procurements under the term of this DSP Program, which expires May 31, 2013.

On January 13, 2012, PECO filed its second Default Service Plan for approval with the PAPUC, which outlined how PECO will purchase electric supply for default service customers from June 1, 2013 through May 31, 2015. The plan proposed to procure electric supply through a combination of one-year and two-year fixed full requirements contracts, reduce the amount of time between when the energy is purchased and when it is provided to customers and complete an annual, rather than quarterly, reconciliation of costs for actual versus forecasted energy use. The plan also proposed several new programs to continue PECO's support of retail market competition in Pennsylvania in accordance with the order issued by the PAPUC on December 15, 2011. Hearings on the filing will be held in the summer of 2012 with a PAPUC ruling expected in mid-October 2012.

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

***Smart Meter and Smart Grid Investments.*** In April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan under which PECO will deploy 600,000 smart meters within three years and deploy smart meters to all of its electric customers by 2020. Also in April 2010, PECO entered into a Financial Assistance Agreement with the DOE for a $200 million award for SGIG funds under the ARRA of 2009. In total, through 2020, PECO plans to spend up to a total of $650 million on its smart grid and smart meter infrastructure. The $200 million SGIG from the DOE is being used to reduce the impact of these investments on PECO ratepayers.

***Financial Reform Legislation.*** The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank) was enacted into law on July 21, 2010. Its primary objective is to eliminate from the financial system the systemic risk that Congress believed was in part the cause of the financial crisis in 2008. Dodd-Frank ushers in a new regulatory framework applicable to the over-the-counter (OTC) market for swaps. Generation relies on the OTC swaps markets as part of its program to hedge the price risk associated with its generation portfolio.

Since the Fall of 2010, the SEC, Commodity Futures Trading Commission (CFTC), and the Federal Reserve have issued hundreds of proposed rules designed to carry out the mandates contained in Dodd-Frank. With respect to non-banks such as Exelon, the primary regulator will be the CFTC. Although a few of the rules that will affect Exelon have become final, most will not until, at the earliest, the middle of 2012.

The starting point that will determine the ultimate impact on Generation is the definition of "swap dealer," as the regulation is aimed at dealers in a manner that is analogous to the CFTC's long-standing jurisdiction over the exchanges, such as the NYMEX, which are the clearinghouses for exchange-traded futures and options. The CFTC has not yet issued its final rule defining swap dealer. Although the regulation applicable to swap dealers will be far more extensive, end-users will also face new requirements that could have a material impact on Generation.

Swap dealers will be subject to significant reporting requirements, both in the normal course to the CFTC or its designee swap data repository (SDR), and in real-time to the CFTC or an SDR as they enter into transactions. Swap dealers will also be required to demand margin from other swap dealers and also entities that are major swap participants (MSPs) that could be above amounts parties' currently request based on current industry norms regarding credit quality. Swap dealers will also have to clear all transactions through CFTC-approved exchanges and clearinghouses, except for transactions that they enter into with end-users that elect to rely on the exception to the clearing requirement available only to end-users whose transactions are hedges of their commercial risk. Swap dealers will have to abide by specific business conduct standards, some of which are similar to fiduciary obligations that entities in other businesses owe to their customers under other laws. Swap dealers will be subject to position limits in a broad range of commodities. Finally, swap dealers will be subject to capitalization requirements that in some cases cannot be met through guarantees from their parent companies.

End-users will also have reporting obligations, but only with respect to some transactions done with other end-users. The clearing requirement will also be applicable to them, except that they will have the option not to clear a transaction that is a qualifying hedge of their commercial risk if they can demonstrate to the CFTC that it is capable of generally meeting its financial obligations associated with uncleared swaps. In addition, end-users will be subject to the same position limits as are applicable to swap dealers.

Although Exelon and Generation believe a swap dealer designation is unlikely for Generation. Generation estimates that a substantial shift from over-the-counter sales to exchange cleared sales would to require up to $1 billion of additional collateral postings by Generation based upon market conditions as of December 31, 2011. The level of collateral required would rely upon multiple factors, including but not limited to market conditions, derivative activity levels and Generation's credit ratings. Generation has adequate credit facilities and flexibility in its hedging program to accommodate these legislative or market changes. Generation continues to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on its results of operations, cash flows or financial position.

***New Jersey Capacity Legislation.*** New Jersey Senate Bill 2381 was enacted into law on January 28, 2011. This legislation established a long-term capacity pilot program under which the New Jersey Board of Public Utilities (NJBPU) administered an RFP process in the first quarter of 2011 to solicit offers for capacity agreements with mid-merit and/or base-load generation constructed after the effective date of the bill. In the first quarter of 2011, the NJBPU approved the RFP results, which included capacity agreements for a term of up to 15 years for 2,000 MWs. Generation and others filed a complaint in Federal district court requesting that the court declare the statute unconstitutional and that it enjoin implementation of the statute, and have filed a motion for summary judgment in that proceeding asking the court to find the state's actions preempted by the Federal Power Act. On December 14, 2011, the NJBPU Staff issued its report on New Jersey Capacity, Transmission Planning and Interconnection Issues. The Report makes several recommendations for NJBPU involvement in ongoing and anticipated PJM activities to revise interconnection and transmission planning processes and recommends continued actions to appeal PJM's MOPR.

The selected generators from the RFP process are required to bid in and clear the PJM RPM auction, likely causing them to bid in the PJM RPM auction at zero. Under the pilot program, generators are paid based on the RFP contract price; therefore, any difference between the RPM clearing price and the RFP contract price is either ultimately recovered from or refunded to New Jersey electric customers. This state-required customer subsidy for generation capacity is expected to artificially suppress capacity prices within the Mid-Atlantic region in future auctions, which could adversely affect Generation's results of operations and cash flows. Other states could seek to establish similar programs, which could substantially impair Exelon's market driven position.

PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. See Note 2 of the Combined Notes to Consolidated Financial Statements for further details related to PJM's MOPR.

***Tax Matters***

***Accounting for Electric Transmission and Distribution Property Repairs.*** On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for repair costs associated with electric transmission and distribution property. For the year ended December 31, 2011, the adoption of the safe harbor resulted in a $35 million reduction of income tax expense at PECO, while Generation incurred additional income tax expense in the amount of $28 million due to a decrease in its manufacturer's deduction. For Exelon, the adoption had a minimal effect on consolidated earnings. In addition, the adoption of the safe harbor will result in a cash tax benefit at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million and $95 million, respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million. See Notes 2 and 11 of the Combined Notes to Consolidated Financial Statements for additional information on the electric transmission and distribution property repairs.

***Nuclear Decommissioning Trust Fund Special Transfer Tax Deduction.*** 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 NDT fund to a qualified NDT fund. As a result of temporary guidance published by the U.S. Department of Treasury, Generation completed a special transfer in the first quarter of 2008 for tax year 2008. In December 2010, the U.S. Department of Treasury issued final regulations under IRC Section 468A. The final regulations included a transitional relief provision that allowed taxpayers to request permission from the IRS to designate a taxable year, as far back as 2006, during which the special transfer will be deemed to have occurred. Exelon determined, and confirmed with the IRS through the ruling process, that this provision allows a majority of Generation's 2008 special transfer deduction to be claimed in the 2006 tax year and the remaining portions claimed ratably in taxable years 2007 and 2008. On February 18, 2011, in order to preserve both the ability to designate the special transfer from 2008 to an earlier taxable year and the ability to complete future additional special transfers, Exelon filed ruling requests with the IRS. During 2011, Exelon received favorable rulings from the IRS on all of its ruling requests. As a result, Exelon recorded an interest and tax benefit of $46 million, net of tax including the impact on the manufacturer's deduction, in 2011 related to the special transfers completed in 2008 and 2011.

***Illinois State Income Tax Legislation.*** The Taxpayer Accountability and Budget Stabilization Act (SB 2505), enacted into law in Illinois on January 13, 2011, increases the corporate tax rate in Illinois from 7.3% to 9.5% for tax years 2011 – 2014, provides for a reduction in the rate from 9.5% to 7.75% for tax years 2015 – 2024 and further reduces the rate from 7.75% to 7.3% for tax years 2025 and thereafter. Pursuant to the rate change, Exelon reevaluated its deferred state income taxes during the first quarter of 2011. Illinois' corporate income tax rate changes resulted in a charge to state deferred taxes (net of Federal taxes) during the first quarter of 2011 of $7 million, $11 million and $4 million for Exelon, Generation and ComEd, respectively. Exelon's and ComEd's charge is net of a regulatory asset recorded of $15 million.

In 2011, the income tax rate change increased Exelon's Illinois income tax provision (net of federal taxes) by approximately $7 million, of which $12 million and $5 million of additional tax relates to Exelon Corporate and Generation, respectively, and a $10 million benefit for ComEd. The 2011 tax benefit at ComEd reflects the impact of a 2011 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010 and the electric transmission and distribution property repairs discussed in Note 11 of the Combined Notes to Consolidated Financial Statements.

### *Plant Retirements*

***Oyster Creek.*** On December 9, 2010, Generation agreed to permanently cease generation operations at Oyster Creek no later than December 31, 2019, in view of the costs that might have been associated with the installation of closed-cycle cooling had operations continued to the end of its current NRC license in 2029.

***Eddystone and Cromby.*** In 2009, Exelon announced its intention to permanently retire three coal-fired generating units and one oil/gas-fired generating unit effective May 31, 2011 in response to the economic outlook related to the continued operation of these four units. However, PJM determined that transmission reliability upgrades would be necessary to alleviate reliability impacts and that those upgrades would be completed in a manner that will permit Generation's retirement of two of the units on that date and two of the units subsequent to May 31, 2011. On May 31, 2011, Cromby Generating Station (Cromby) Unit 1 and Eddystone Generating Station (Eddystone) Unit 1 were retired; on December 31, 2011, Cromby Unit 2 was retired and Eddystone Unit 2 will retire on May 31, 2012. On May 27, 2011, the FERC approved a settlement providing for a reliability-must-run rate schedule, which defines compensation to be paid to Generation for continuing to operate these units. The monthly fixed-cost recovery during the reliability-must-run period for Eddystone Unit 2 is approximately $6 million. In addition, Generation is recovering variable costs including fuel, emissions costs, chemicals, auxiliary power and for project investment costs during the reliability-must-run period. Eddystone Unit 2 and Cromby Unit 2 began operating under the reliability-must-run agreement effective June 1, 2011.

### Critical Accounting Policies and Estimates

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

**Nuclear Decommissioning Asset Retirement Obligations**

Generation must make significant estimates and assumptions in accounting for its obligation to decommission its nuclear generating plants in accordance with the authoritative guidance for AROs. Generation's ARO associated with decommissioning its nuclear units was $3.7 billion at December 31, 2011.

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

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

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

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

***License Renewals.*** Generation assumes a successful 20-year renewal for each of its nuclear generating station licenses, except for Oyster Creek, in determining its nuclear decommissioning ARO. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information on Oyster Creek. Generation has successfully secured 20-year operating license renewal extensions for ten of its nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG), and none of Generation's applications for an operating license extension has been denied. Generation is in various stages of the process of pursuing similar extensions on its remaining nine operating nuclear units. Generation's assumption regarding license extension for ARO determination purposes is based in part on the good current physical condition and high performance of these nuclear units; the favorable status of the ongoing license renewal proceedings with the NRC, and the successful renewals for ten units to date. Generation estimates that the failure to obtain license renewals at any of these nuclear units (assuming all other assumptions remain constant) would increase its ARO on average approximately $170 million per unit as of December 31, 2011. The size of the increase to the ARO for a particular nuclear unit is dependent upon the current stage in its original license term and its specific decommissioning cost estimates. If Generation does not receive license renewal on a particular unit, the increase to the ARO may be mitigated by Generation's ability to delay ultimate decommissioning activities under a SAFSTOR method of decommissioning.

***Discount Rates.*** The probability-weighted estimated future cash flows using these various scenarios are discounted using credit-adjusted, risk-free rates (CARFR) applicable to the various businesses in which each of the nuclear units originally operated. Changes in the CARFR could result in significant changes in the ARO. If Generation used a 2010 CARFR instead of the 2011 CARFR in performing its third quarter 2011 ARO update, it would have resulted in a $140 million increase in the ARO. Additionally, if the CARFR used in performing the third quarter 2011 ARO update was increased or decreased by 25 basis points, the ARO would have decreased by $50 million or increased by $20 million, respectively.

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

| Change in ARO Assumption | Increase to ARO at December 31, 2011 |
|---|---|
| **Cost escalation studies** | |
| Uniform increase in escalation rates of 25 basis points | $410 |
| **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 | $120 |
| Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points | $180 |
| 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 | $340 |
| Extend the estimated date for DOE acceptance of SNF to 2025 | $150 |
| Extend the estimated date for DOE acceptance of SNF to 2035 | $250 |

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

**Goodwill**

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

ComEd did not recognize an impairment in 2011; however, a fully successful IRS challenge to Exelon's and ComEd's like-kind exchange income tax position or adverse regulatory actions such as early termination of EIMA in combination with changes in significant assumptions described above could potentially result in a future impairment loss of ComEd's goodwill, which could be material. If any combination of changes to significant assumptions resulted in a 5% reduction in the fair value of the reporting unit as of November 1, 2011, ComEd still would have passed the first step of the goodwill assessment. See Notes 2 and 7 of the Combined Notes to Consolidated Financial Statements for additional information.

**Purchase Accounting**

In accordance with the authoritative accounting guidance, the purchase price of an acquired business is generally allocated to the assets acquired and liabilities assumed at their estimated fair values on the date of acquisition. Any unallocated purchase price amount is recognized as goodwill on the balance sheet if it exceeds the estimated fair value and as a bargain purchase gain on the income statement if it is below the estimated fair value. Determining the fair value of assets acquired and liabilities assumed in a business combination is judgmental in nature and often involves the use of significant estimates and assumptions. Some of the more significant estimates and assumptions used in valuing Generation's acquisitions of Antelope Valley Solar Ranch One on September 28, 2011, Wolf Hollow, LLC on August 24, 2011 and Exelon Wind on December 10, 2010 include: projected future cash flows (including timing) which are estimated primarily utilizing the income approach; discount rates reflecting the risk inherent in the future cash flows; and future market prices. The determination of fair value is driven by both internal assumptions as well as information from various public, financial and industry sources. There are also judgments made to determine the expected useful lives assigned to each class of assets acquired and the duration of the liabilities assumed. The judgments made in the determination of the estimated fair value assigned to the assets acquired and liabilities assumed, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

**Impairment of Long-lived Assets**

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

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

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

**Depreciable Lives of Property, Plant and Equipment**

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

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

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

PECO is required to file a depreciation rate study at least every five years with the PAPUC. In April 2010, PECO filed a depreciation rate study with the PAPUC for both its electric and gas assets, which resulted in the implementation of new depreciation rates effective January 1, 2011.

**Defined Benefit Pension and Other Postretirement Benefits**

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

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

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

***Expected Rate of Return on Plan Assets.*** The long-term expected rate of return on plan assets assumption used in calculating pension costs was 8.00%, 8.50% and 8.50% for 2011, 2010 and 2009, respectively. The weighted average expected return on assets assumption used in calculating other postretirement benefit costs was 7.08%, 7.83% and 8.10% in 2011, 2010 and 2009, respectively. The pension trust activity is non-taxable, while other postretirement benefit trust activity is partially taxable. The current year EROA is based on asset allocations from the prior year end. In 2010, Exelon began implementation of a liability driven investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. As a result of this modification, over time, Exelon determined that it will decrease equity investments and increase investments in fixed income securities and alternative investments in order to achieve a balanced portfolio of liability hedging and return-generating assets. The change in the overall investment strategy would tend to lower the expected rate of return on plan assets in future years as compared to the previous strategy. See Note 13 of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's asset allocations. Exelon used an EROA of 7.50% and 6.68% to estimate its 2012 pension and other postretirement benefit costs, respectively.

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

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and other postretirement benefit plans. The actual asset returns for Exelon's pension and other postretirement benefit plans for the year ended December 31, 2011 were 9.8% and 2.0%, respectively, compared to an expected long-term return assumption of 8.00% and 7.08%, respectively.

***Discount Rate.*** The discount rates used to determine the pension and other postretirement benefit obligations at December 31, 2011 were 4.74% and 4.80%, respectively, and the discount rates for determining the pension and other postretirement benefit obligations at December 31, 2010 were 5.26% and 5.30%, respectively. At December 31, 2011 and 2010, the discount rates were determined by developing a spot rate curve based on the yield to maturity of a universe of high-quality non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and other postretirement benefit obligations. The spot rates are used to discount the estimated distributions under the pension and other postretirement benefit plans. The discount rate is the single level rate that produces the same result as the spot rate curve. Exelon utilizes an analytical tool developed by its actuaries to determine the discount rates.

The discount rate assumptions used to determine the obligation at year end are used to determine the cost for the following year. Exelon will use discount rates of 4.74% and 4.80% to estimate its 2012 pension and other postretirement benefit costs, respectively.

***Health Care Reform Legislation.*** In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers. One such provision reduces the deductibility, for Federal income tax purposes, of retiree health care costs to the extent an employer's postretirement health care plan receives Federal subsidies that provide retiree prescription drug benefits at least equivalent to those offered by Medicare. Although this change did not take effect immediately, Exelon was required to recognize the full accounting impact in their financial statements in the period in which the legislation was enacted. Additionally, as a result of this deductibility change for employers and other Health Care Reform provisions that impact the federal prescription drug subsidy options provided to employers, Exelon intends to make a change in the manner in which it receives prescription drug subsidies in 2013.

The Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Although the excise tax does not go into effect until 2018, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Certain key assumptions are required to estimate the impact of the excise tax on Exelon's other postretirement obligation, including projected inflation rates (based on the CPI) and whether pre- and post-65 retiree populations can be aggregated in determining the premium values of health care benefits. Exelon reflected its best estimate of the expected impact in its annual actuarial valuation.

***Health Care Cost Trend Rate.*** Assumed health care cost trend rates have a significant effect on the costs reported for Exelon's other postretirement benefit plans. Accounting guidance requires that annual health care cost estimates be developed using past and present health care cost trends (both for Exelon and across the broader economy), as well as expectations of health care cost escalation, changes in health care utilization and delivery patterns, technological advances and changes in the health status of plan participants. Therefore, the trend rate assumption is subject to significant uncertainty, particularly when considering potential impacts of the 2010 Health Care Reform Acts. Exelon assumed an initial health care cost trend rate of 6.50% at December 31, 2011, decreasing to an ultimate health care cost trend rate of 5.00% in 2017.

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

| Actuarial Assumption | Change in Assumption | Pension | Other Postretirement Benefits | Total |
|---|---|---|---|---|
| Change in 2011 cost: | | | | |
| Discount rate [a] | 0.5% | $ (54) | $ (23) | $ (77) |
| | (0.5%) | 54 | 30 | 84 |
| EROA | 0.5% | (59) | (8) | (67) |
| | (0.5%) | 59 | 8 | 67 |
| Health care cost trend rate | 1.00% | N/A | 75 | 75 |
| | (1.00%) | N/A | (57) | (57) |
| | Extend the year at which the ultimate health care trend rate of 5% is forecasted to be reached from 2015 to 2017 | N/A | 6 | 6 |
| Change in benefit obligation at December 31, 2011: | | | | |
| Discount rate [a] | 0.5% | (819) | (252) | (1,071) |
| | (0.5%) | 873 | 269 | 1,142 |
| Health care cost trend rate | 1.00% | N/A | 686 | 686 |
| | (1.00%) | N/A | (521) | (521) |
| | Extend the year at which the ultimate health care trend rate of 5% is forecasted to be reached from 2015 to 2017 | N/A | 61 | 61 |

(a) In general, the discount rate will have a larger impact on the pension and other postretirement benefit cost and obligation as the rate moves closer to 0%. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated for larger increases or decreases in the discount rate. Additionally, Exelon implemented a liability-driven investment strategy for a portion of its pension asset portfolio in 2010. The sensitivities shown above do not reflect the offsetting impact that changes in discount rates may have on pension asset returns.

***Average Remaining Service Period.*** For pension benefits, Exelon amortizes its unrecognized prior service costs and certain actuarial gains and losses, as applicable, based on participants' average remaining service periods. The average remaining service period of defined benefit pension plan participants was 12.1 years, 12.4 years and 12.7 years for the years ended December 31, 2011, 2010 and 2009, respectively.

For other postretirement benefits, Exelon amortizes its unrecognized estimated prior service costs over participants' average remaining service period to benefit eligibility age and amortizes its transition obligations and certain actuarial gains and losses over participants' average remaining service period to expected retirement. The average remaining service period of postretirement benefit plan participants related to benefit eligibility age was 6.6 years, 6.8 years and 6.8 years for the years ended December 31, 2011, 2010 and 2009, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 8.7 years, 9.0 years and 9.2 years for the years ended December 31, 2011, 2010 and 2009, respectively.

### Regulatory Accounting

Exelon, ComEd and PECO account for their regulated electric and gas operations in accordance with the authoritative guidance for accounting for certain types of regulations, which requires Exelon, ComEd, and PECO to reflect the effects of cost-based rate regulation in their financial statements. This guidance is applicable to entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) a reasonable expectation that rates are set at levels that will recover the entities costs from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent (1) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (2) billings in advance of expenditures for approved regulatory programs. As of December 31, 2011, Exelon, ComEd and PECO have concluded that the operations of ComEd and PECO meet the criteria to apply the authoritative guidance. If it is concluded in a future period that a separable portion of those operations no longer meets the criteria of this guidance, Exelon, ComEd and PECO would be required to eliminate any associated regulatory assets and liabilities and the impact would be recognized in the Consolidated Statements of Operations and could be material. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon, ComEd and PECO.

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

### Accounting for Derivative Instruments

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

Exelon accounts for derivative financial instruments under the applicable authoritative guidance. Determining whether or not a contract qualifies as a derivative under this guidance requires that management exercise significant judgment, including assessing the market liquidity as well as determining whether a contract has one or more underlyings and one or more notional amounts. Further, interpretive guidance related to the authoritative literature continues to evolve, including how it applies to energy and energy-related products. Changes in management's assessment of contracts and the liquidity of their markets, and changes in authoritative guidance related to derivatives, could result in previously excluded contracts being subject to the provisions of the authoritative derivative guidance. Generation has determined that contracts to purchase uranium and contracts to purchase and sell RECs do not meet the definition of a derivative under the current authoritative guidance since they do not provide for net settlement and neither the uranium nor the REC markets are sufficiently liquid to conclude that forward contracts are readily convertible to cash. If the uranium or REC markets do become sufficiently liquid in the future and Generation begins to account for uranium purchase contracts or REC sale and 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 current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value unless they qualify for a normal purchases and normal sales exception. Further, derivatives that qualify and are designated for hedge accounting are classified as fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting and for energy-related derivatives entered into for proprietary trading purposes, changes in the fair value of the derivatives are recognized in earnings each period except for ComEd and PECO, in which changes in the fair value each period are recorded as a regulatory asset or liability.

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

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

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

***Interest Rate Derivative Instruments.*** 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. Additionally, Exelon may use forward-starting interest rate swaps and treasury rate locks to lock in interest-rate levels in anticipation of future financings. The fair value of the swap agreements is calculated by discounting the future net cash flows to the present value based on the terms and conditions of the agreements and the forward interest rate curves. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy.

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

### Taxation

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

Exelon evaluates quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. Exelon also assesses 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. Exelon records valuation allowances for deferred tax assets when Exelon concludes it is more likely than not such benefit will not be realized in future periods.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, Exelon's forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. While Exelon believes the resulting tax balances as of December 31, 2011 and 2010 are appropriately accounted for in accordance with the applicable authoritative guidance, the ultimate outcome of tax matters could result in favorable or unfavorable adjustments to their consolidated financial statements and such adjustments could be material. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

### Accounting for Loss Contingencies

In the preparation of their financial statements, Exelon makes judgments regarding the future outcome of contingent events and record liabilities for loss contingencies that are probable and can be reasonably estimated based upon available information. The amounts recorded may differ from the actual expense incurred when the uncertainty is resolved. The estimates that Exelon makes in accounting for loss contingencies and the actual results that they record upon the ultimate resolution of these uncertainties could have a significant effect on the consolidated financial statements.

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

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

### Revenue Recognition

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

ComEd's distribution formula rate tariff, pursuant to EIMA, and ComEd's FERC-approved transmission formula rate tariff provide for annual reconciliations to the distribution and transmission revenue requirements, respectively. As of the balance sheet dates, ComEd has recorded its best estimates of the distribution and transmission revenue impacts resulting from changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with the formula rate mechanisms. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. Both estimated reconciliations can be impacted by, among other things, variances in costs incurred and investments made and actions by regulators or courts. The structure of ComEd's distribution formula rate tariff could change once the ICC proceeding to review ComEd's initially filed formula rate tariff is completed in May 2012. ComEd does not anticipate that any of the adjustments to the reconciliations discussed above would be material to ComEd's overall results of operations, financial position or cash flows.

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

### Allowance for Uncollectible Accounts

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

### Results of Operations by Business Segment

The comparisons of operating results and other statistical information for the years ended December 31, 2011, 2010 and 2009 set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

***Net Income (Loss) by Business Segment***

| | 2011 | 2010 | Favorable (unfavorable) 2011 vs. 2010 variance | 2009 | Favorable (unfavorable) 2010 vs. 2009 variance |
|---|---|---|---|---|---|
| Generation | $1,771 | $1,972 | $(201) | $2,122 | $(150) |
| ComEd | 416 | 337 | 79 | 374 | (37) |
| PECO | 389 | 324 | 65 | 353 | (29) |
| Other [(a)] | (81) | (70) | (11) | (142) | 72 |
| Total | $2,495 | $2,563 | $ (68) | $2,707 | $(144) |

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

*Results of Operations—Generation*

| | 2011 | 2010 | Favorable (unfavorable) 2011 vs. 2010 variance | 2009 | Favorable (unfavorable) 2010 vs. 2009 variance |
|---|---|---|---|---|---|
| **Operating revenues** | $10,308 | $10,025 | $ 283 | $9,703 | $ 322 |
| **Purchased power and fuel expense** | 3,450 | 3,463 | 13 | 2,932 | (531) |
| **Revenue net of purchased power and fuel expense** [(a)] | 6,858 | 6,562 | 296 | 6,771 | (209) |
| **Other operating expenses** | | | | | |
| Operating and maintenance | 3,148 | 2,812 | (336) | 2,938 | 126 |
| Depreciation and amortization | 570 | 474 | (96) | 333 | (141) |
| Taxes other than income | 264 | 230 | (34) | 205 | (25) |
| Total other operating expenses | 3,982 | 3,516 | (466) | 3,476 | (40) |
| **Operating income** | 2,876 | 3,046 | (170) | 3,295 | (249) |
| **Other income and deductions** | | | | | |
| Interest expense | (170) | (153) | (17) | (113) | (40) |
| Loss in equity method investments | (1) | — | (1) | (3) | 3 |
| Other, net | 122 | 257 | (135) | 376 | (119) |
| Total other income and deductions | (49) | 104 | (153) | 260 | (156) |
| **Income before income taxes** | 2,827 | 3,150 | (323) | 3,555 | (405) |
| **Income taxes** | 1,056 | 1,178 | 122 | 1,433 | 255 |
| **Net income** | $ 1,771 | $ 1,972 | $(201) | $2,122 | $(150) |

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

***Net Income***

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* Generation's net income decreased compared to the same period in 2010 primarily due to mark-to-market losses on economic hedging activities and higher operating and maintenance expenses. Generation's 2011 results were further affected by increased nuclear fuel costs, less favorable NDT fund performance in 2011 and higher nuclear refueling outage costs associated with the increased number of refueling outage days in 2011. These unfavorable impacts were partially offset by higher revenues due to the expiration of the PECO PPA on December 31, 2010 and favorable market and portfolio conditions in the South and West region.

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

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

### *Revenue Net of Purchased Power and Fuel Expense*

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

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

For the year ended December 31, 2011 compared to 2010 and 2010 compared to 2009, Generation's revenue net of purchased power and fuel expense by region were as follows:

| | 2011 | 2010 | 2011 vs. 2010 Variance | 2011 vs. 2010 % Change | 2009 | 2010 vs. 2009 Variance | 2010 vs. 2009 % Change |
|---|---|---|---|---|---|---|---|
| Mid-Atlantic [a][b] | $3,359 | $2,512 | $ 847 | 33.7% | $2,578 | $ (66) | (2.6)% |
| Midwest [b] | 3,547 | 4,081 | (534) | (13.1)% | 4,148 | (67) | (1.6)% |
| South and West | 70 | (131) | 201 | 153.4% | (117) | (14) | (12.0)% |
| Total electric revenue net of purchased power and fuel expense | $6,976 | $6,462 | $ 514 | 8.0% | $6,609 | $(147) | (2.2)% |
| Trading portfolio | 24 | 27 | (3) | (11.1)% | 1 | 26 | n.m. |
| Mark-to-market gains (losses) | (288) | 86 | (374) | n.m. | 181 | (95) | (52.5)% |
| Other [c][d] | 146 | (13) | 159 | n.m. | (20) | 7 | 35.0% |
| Total revenue net of purchased power and fuel expense | $6,858 | $6,562 | $ 296 | 4.5% | $6,771 | $(209) | (3.1)% |

(a) Included in the Mid-Atlantic are the results of generation in New England.

(b) Results of transactions with PECO and ComEd are included in the Mid-Atlantic and Midwest regions, respectively.

(c) Includes retail gas activities and other operating revenues, which primarily include fuel sales and compensation under the reliability-must-run rate schedule.

(d) In 2010, Other also includes a $57 million impairment charge for certain emission allowances further described in Note 18 of the Combined Notes to Consolidated Financial Statements.

Generation's supply sources by region are summarized below:

| Supply source (GWh) | 2011 | 2010 | 2011 vs. 2010 Variance | 2011 vs. 2010 % Change | 2009 | 2010 vs. 2009 Variance | 2010 vs. 2009 % Change |
|---|---|---|---|---|---|---|---|
| Nuclear generation [(a)] | | | | | | | |
| Mid-Atlantic | 47,287 | 47,517 | (230) | (0.5)% | 47,866 | (349) | (0.7)% |
| Midwest | 92,010 | 92,493 | (483) | (0.5)% | 91,804 | 689 | 0.8% |
| Fossil and renewables | | | | | | | |
| Mid-Atlantic [(a)(b)] | 7,580 | 9,436 | (1,856) | (19.7)% | 8,938 | 498 | 5.6% |
| Midwest [(c)] | 596 | 68 | 528 | n.m. | 4 | 64 | n.m. |
| South and West [(c)] | 3,462 | 1,213 | 2,249 | 185.4% | 1,247 | (34) | (2.7)% |
| Purchased power [(d)] | | | | | | | |
| Mid-Atlantic | 2,898 | 1,918 | 980 | 51.1% | 1,747 | 171 | 9.8% |
| Midwest | 5,970 | 7,032 | (1,062) | (15.1)% | 7,738 | (706) | (9.1)% |
| South and West | 10,040 | 12,112 | (2,072) | (17.1)% | 13,721 | (1,609) | (11.7)% |
| Total supply by region | | | | | | | |
| Mid-Atlantic | 57,765 | 58,871 | (1,106) | (1.9)% | 58,551 | 320 | 0.5% |
| Midwest | 98,576 | 99,593 | (1,017) | (1.0)% | 99,546 | 47 | 0.0% |
| South and West | 13,502 | 13,325 | 177 | 1.3% | 14,968 | (1,643) | (11.0)% |
| Total supply | 169,843 | 171,789 | (1,946) | (1.1)% | 173,065 | (1,276) | (0.7)% |

(a) Includes Generation's proportionate share of the output of its jointly owned generating plants.
(b) Includes generation in New England and excludes revenue under the reliability-must-run rate schedule.
(c) Includes generation from Exelon Wind, acquired in December 2010, of 570 GWh and 41 GWh in the Midwest and 1,432 GWh and 84 GWh in the South and West for the years ended December 31, 2011 and 2010, respectively.
(d) Includes non-PPA purchases of 3,815 GWh, 4,681 GWh and 3,535 GWh for the years ended December 31, 2011, 2010 and 2009, respectively.

Generation's sales are summarized below:

| Sales (GWh) [(a)] | 2011 | 2010 | 2011 vs. 2010 Variance | 2011 vs. 2010 % Change | 2009 | 2010 vs. 2009 Variance | 2010 vs. 2009 % Change |
|---|---|---|---|---|---|---|---|
| ComEd [(b)] | — | 5,323 | (5,323) | (100.0)% | 16,830 | (11,507) | (68.4)% |
| PECO [(c)] | — | 42,003 | (42,003) | (100.0)% | 39,897 | 2,106 | 5.3% |
| Market and retail [(d)] | 169,843 | 124,463 | 45,380 | 36.5% | 116,338 | 8,125 | 7.0% |
| Total electric sales | 169,843 | 171,789 | (1,946) | (1.1)% | 173,065 | (1,276) | (0.7)% |

(a) Excludes physical trading volumes of 5,742 GWh, 3,625 GWh and 7,578 GWh for the years ended December 31, 2011, 2010 and 2009, respectively.
(b) Represents sales under the 2006 ComEd auction.
(c) Represents sales under the full requirements PPA, which expired on December 31, 2010.
(d) Includes sales under the ComEd RFP, settlements under the ComEd swap and sales to PECO through the competitive procurement process.

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the year ended December 31, 2011 as compared to the same period in 2010 and 2010 as compared to the same period in 2009.

| $/MWh | 2011 | 2010 | 2011 vs. 2010 % Change | 2009 | 2010 vs. 2009 % Change |
|---|---|---|---|---|---|
| Mid-Atlantic [(a)(b)] | $58.15 | $42.67 | 36.3% | $44.03 | (3.1)% |
| Midwest [(a)(c)] | $35.98 | $40.98 | (12.2)% | $41.67 | (1.7)% |
| South and West | $ 5.18 | $ (9.83) | 152.7% | $ (7.82) | (25.7)% |
| Electric revenue net of purchased power and fuel expense per MWh [(d)] | $41.07 | $37.62 | 9.2% | $38.20 | (1.5)% |

(a) Results of transactions with PECO and ComEd are included in the Mid-Atlantic and Midwest regions, respectively.
(b) Includes sales to PECO of $508 million (7,041 GWh), $2,091 million (42,003 GWh) and $2,016 million (39,897 GWh) for the years ended December 31, 2011, 2010 and 2009, respectively. Excludes compensation under the reliability-must-run rate schedule.

(c) Includes sales to ComEd of $179 million (4,731 GWh), $288 million (8,218 GWh) and $88 million (1,916 GWh) and settlements of the ComEd swap of $474 million, $385 million and $292 million for the years ended December 31, 2011, 2010 and 2009, respectively.

(d) Revenue net of purchased power and fuel expense per MWh represents the average margin per MWh of electricity sold during the years ended December 31, 2011, 2010 and 2009 and excludes the mark-to-market impact of Generation's economic hedging activities, trading portfolio and other.

*Mid-Atlantic*

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* The $847 million increase in revenue net of purchased power and fuel expense in the Mid-Atlantic was primarily due to increased margins on the volumes previously sold under Generation's PPA with PECO, which expired on December 31, 2010, partially offset by increased nuclear fuel costs.

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

*Midwest*

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* The $534 million decrease in revenue net of purchased power and fuel expense in the Midwest was primarily due to decreased realized margins in 2011 for the volumes previously sold by Generation under the 2006 ComEd auction contracts and increased nuclear fuel costs. These decreases were partially offset by increased capacity revenues, favorable settlements under the ComEd swap and the additional revenue following the acquisition of Exelon Wind in December 2010.

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

*South and West*

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

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* The $201 million increase in revenue net of purchased power and fuel expense in the South and West was primarily driven by the performance of Generation's generating units during extreme weather events that occurred in Texas in February and August 2011, in addition to the impact of additional revenue from the acquisition of Exelon Wind in December 2010 and higher realized margins due to overall favorable market conditions.

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

*Mark-to-market Gains and Losses*

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

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* Mark-to-market losses on power hedging activities were $214 million in 2011, including the impact of the changes in ineffectiveness, compared to losses of $3 million in 2010. Mark-to-market losses on fuel hedging activities were $74 million in 2011 compared to gains of $89 million in 2010. In general, the mark-to-market losses incurred in 2011 represent the realization of in-the-money hedge transactions during the period. See Notes 8 and 9 of the Combined Notes to Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

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

*Other*

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* The increase in other revenue net of purchased power and fuel expense is primarily due to the impacts of the impairment charge of certain emission allowances recognized in 2010, additional other wholesale fuel sales in 2011 as well as compensation under the reliability-must-run rate schedule further described in Note 14 of the Combined Notes to Consolidated Financial Statements.

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

**Nuclear Fleet Capacity Factor and Production Costs**

The following table presents nuclear fleet operating data for 2011, as compared to 2010 and 2009, for the Exelon-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Nuclear fleet production cost is defined as the costs to produce one MWh of energy, including fuel, materials, labor, contracting and other miscellaneous costs, but excludes depreciation and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Nuclear fleet capacity factor [a] | 93.3% | 93.9% | 93.6% |
| Nuclear fleet production cost per MWh [a] | $18.86 | $17.31 | $16.07 |

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

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* The nuclear fleet capacity factor, which excludes Salem, decreased primarily due to a higher number of planned refueling outage days. For 2011 and 2010, scheduled refueling outage days totaled 283 and 261, respectively. Higher nuclear fuel costs and higher plant operating and maintenance costs resulted in a higher production cost per MWh during 2011 as compared to 2010.

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

***Operating and Maintenance Expense***

The changes in operating and maintenance expense for 2011 compared to 2010, consisted of the following:

| | Increase (Decrease) |
|---|---|
| Labor, other benefits, contracting and materials | $113 |
| Nuclear refueling outage costs, including the co-owned Salem plant [(a)] | 74 |
| Exelon Wind [(b)] | 39 |
| Asset retirement obligation increase [(c)] | 28 |
| 2010 nuclear insurance credit [(d)] | 20 |
| Corporate allocations [(e)] | 19 |
| Acquisition costs [(f)] | 14 |
| Other [(g)] | 29 |
| Increase in operating and maintenance expense | $336 |

(a) Reflects the impact of increased planned refueling outages during 2011.
(b) Includes costs of $30 million in 2011 associated with labor, other benefits, contracting and materials at Exelon Wind.
(c) Reflects an increase in Generation's decommissioning obligation for spent nuclear fuel at Zion. See Note 12 of the Combined Notes to Consolidated Financial Statements for further information regarding the ARO update in 2011.
(d) Reflects the impact of the return of property and business interruption insurance premiums in 2010. No premiums were returned for 2011.
(e) Primarily reflects increased lobbying expenses related to EPA and competitive market matters.
(f) Reflects the increase in certain costs associated with the acquisitions of Exelon Wind, Wolf Hollow, Antelope Valley and the proposed acquisition of Constellation incurred in 2011. See Note 3 of the Combined Notes to Consolidated Financial Statements for further information.
(g) Includes additional environmental remediation costs recorded during 2011.

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

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

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

***Depreciation and Amortization***

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the acquisition of Exelon Wind, capital additions and other upgrades to existing facilities. Higher plant balances resulted in an increase in depreciation and amortization expense of $61 million. The remaining increase in depreciation and amortization expense was due to the impact of increases in asset retirement costs (ARC) for Generation's nuclear generating facilities.

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

***Taxes Other Than Income***

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* The increase was primarily due to increased gross receipt taxes related to retail sales in the Mid-Atlantic region. These gross receipt taxes are recovered in revenue, and as a result, have no impact to Generation's results of operations.

*Year Ended December 31, 2010 Compared to Year Ended December 31, 2009.* The increase was primarily due to increased property taxes related to Generation's nuclear-fuel generating facilities.

***Interest Expense***

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* The increase in interest expense is primarily due to debt issuances in 2010, further described in Note 10 of the Combined Notes to Consolidated Financial Statements. The increase in long-term debt resulted in higher interest expense of approximately $27 million.

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

***Other, Net***

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* The decrease in other, net primarily reflects net unrealized losses related to the NDT funds of its Non-Regulatory Agreement Units compared to net unrealized gains in 2010, as described in the table below. Additionally, the decrease reflects the contractual elimination of $18 million of income tax expense associated with the NDT funds of the Regulatory Agreement Units in 2011 compared to the contractual elimination of $96 million of income tax expense in 2010. These decreases are partially offset by the $32 million impact of one-time interest income from the NDT fund special transfer tax deduction recognized in 2011 and a $36 million bargain purchase gain associated with the August 2011 acquisition of Wolf Hollow.

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

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in other, net for 2011, 2010 and 2009:

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Net unrealized gains (losses) on decommissioning trust funds | $ (4) | $104 | $227 |
| Net realized gains (losses) on sale of decommissioning trust funds | $(10) | $ 2 | $ (19) |

***Effective Income Tax Rate.***

Generation's effective income tax rates for the years ended December 31, 2011, 2010 and 2009 were 37.4%, 37.4% and 40.3%, respectively. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

**Results of Operations—ComEd**

| | 2011 | 2010 | Favorable (unfavorable) 2011 vs. 2010 variance | 2009 | Favorable (unfavorable) 2010 vs. 2009 variance |
|---|---|---|---|---|---|
| **Operating revenues** | $6,056 | $6,204 | $(148) | $5,774 | $ 430 |
| Purchased power expense | 3,035 | 3,307 | 272 | 3,065 | (242) |
| **Revenue net of purchased power expense** [(a)] | 3,021 | 2,897 | 124 | 2,709 | 188 |
| **Other operating expenses** | | | | | |
| Operating and maintenance | 1,086 | 975 | (111) | 1,028 | 53 |
| Operating and maintenance for regulatory required programs | 115 | 94 | (21) | 63 | (31) |
| Depreciation and amortization | 542 | 516 | (26) | 494 | (22) |
| Taxes other than income | 296 | 256 | (40) | 281 | 25 |
| Total other operating expenses | 2,039 | 1,841 | (198) | 1,866 | 25 |
| **Operating income** | 982 | 1,056 | (74) | 843 | 213 |
| **Other income and deductions** | | | | | |
| Interest expense, net | (345) | (386) | 41 | (319) | (67) |
| Other, net | 29 | 24 | 5 | 79 | (55) |
| Total other income and deductions | (316) | (362) | 46 | (240) | (122) |
| **Income before income taxes** | 666 | 694 | (28) | 603 | 91 |
| **Income taxes** | 250 | 357 | 107 | 229 | (128) |
| **Net income** | $ 416 | $ 337 | $ 79 | $ 374 | $ (37) |

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

***Net Income***

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* The increase in ComEd's net income was primarily due to higher electric distribution rates, effective June 1, 2011, pursuant to the ICC order in the 2010 Rate Case, and increased revenues resulting from the annual reconciliation of ComEd's distribution revenue requirement pursuant to EIMA, which became effective in the fourth quarter of 2011. Net income was also higher due to the remeasurement of uncertain income tax positions in 2010 related to the 1999 sale of ComEd's fossil generating assets. The remeasurement resulted in increased interest expense and income tax expense recorded in 2010. These increases to net income were partially offset by higher operating and maintenance expense and taxes other than income.

The increase in operating and maintenance expense reflects the benefit recorded in 2010 resulting from the ICC's approval of ComEd's uncollectible accounts expense rider mechanism, a reduction in ComEd's ARO reserve in 2010, and higher labor and contracting expenses incurred in 2011. These increases to operating and maintenance expense were partially offset by one-time net benefits recognized pursuant to the ICC order in ComEd's 2010 rate case.

*Year Ended December 31, 2010 Compared to Year Ended December 31, 2009.* The decrease in ComEd's net income was primarily due to the remeasurement of uncertain income tax positions in 2009 and 2010 related to the 1999 sale of ComEd's fossil generating assets. These remeasurements resulted in increased interest expense and income tax expense recorded in 2010, and increased interest income recorded in 2009. Net income was also reduced by higher incremental storm costs, higher depreciation and amortization expense reflecting higher plant balances, and the impact of Federal health care legislation signed into law in March 2010. These reductions to net income were partially offset by higher revenue net of purchased power expense primarily due to favorable weather conditions, a net reduction in operating and maintenance expense, and the accrual of estimated future refunds of the Illinois utility distribution tax for the 2008 and 2009 tax years.

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

***Operating Revenues Net of Purchased Power Expense***

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

Electric revenues and purchased power expense are affected by fluctuations in customers' purchases from competitive electric generation suppliers. All ComEd customers have the ability to purchase electricity from an alternative electric generation supplier. The customer choice of electric generation supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and generation services. The number of retail customers purchasing electricity from competitive electric generation suppliers was 380,300 and 66,200 at December 31, 2011 and 2010, respectively, representing 10% and 2% of total retail customers, respectively. The significant increase in 2011 is primarily associated with the residential customer class. Retail deliveries purchased from competitive electric generation suppliers represented 56% and 52% of ComEd's retail kWh sales at December 31, 2011 and 2010, respectively.

The changes in ComEd's electric revenue net of purchased power expense for 2011 compared to 2010 consisted of the following:

| | Increase (Decrease) |
|---|---|
| Pricing (2010 Rate Case) | $ 89 |
| Revenues subject to refund, net | 31 |
| Distribution formula rate reconciliation | 29 |
| Regulatory required programs cost recovery | 21 |
| Transmission | 18 |
| 2007 City of Chicago Settlement | 2 |
| Volume—delivery | (10) |
| Weather—delivery | (21) |
| Uncollectible accounts recovery, net | (33) |
| Other | (2) |
| Total increase | $124 |

*Pricing (2010 Rate Case)*

The ICC issued an order in the 2010 Rate Case approving an increase in ComEd's annual electric distribution revenue requirement. The order became effective June 1, 2011, resulting in higher revenues for the year ended December 31, 2011 compared to the same period in 2010. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

*Revenues subject to refund, net*

ComEd records revenues subject to refund based upon its best estimate of customer collections that may be required to be refunded. As a result of the September 30, 2010 Illinois Appellate Court (Court) decision in the 2007 Rate Case that ruled against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via Rider SMP, ComEd began recording revenue subject to refund prospectively. In addition, ComEd began recording revenue subject to refund on

June 1, 2010 relating to the recovery of Cash Working Capital (CWC) through its energy procurement rider. Based on the 2010 Rate Case order as well as ongoing proceedings associated with the Court order, ComEd has updated its revenue subject to refund reserve. As of December 31, 2011, ComEd has recorded its best estimate of any refund obligations. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

*Distribution formula rate reconciliation*

EIMA provides for a performance-based formula rate tariff. The legislation provides for an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. ComEd will make its initial reconciliation filing in May 2012 and the adjusted rates will take effect in January 2013 after ICC review. As of December 31, 2011, ComEd recorded an estimated reconciliation of approximately $29 million. This does not include the reconciliation of significant storm costs discussed under operating and maintenance expense below. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

*Regulatory required programs cost recovery*

Revenues related to regulatory required programs are the recoveries from customers of costs for various legislative and/or regulatory programs on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating and maintenance for regulatory required programs during the period presented. See Note 2 of the Combined Notes to Financial Statements for additional information.

*Transmission*

ComEd's transmission rates are established based on a FERC-approved formula. ComEd's most recent annual formula rate update, filed in May 2011, reflects actual 2010 expenses and investments plus forecasted 2011 capital additions. Transmission revenues net of purchased power expense vary from year to year based upon fluctuations in the underlying costs and investments being recovered. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

*2007 City of Chicago Settlement*

ComEd paid $1 million and $3 million in 2011 and 2010, respectively, under the terms of its 2007 settlement agreement with the City of Chicago. Payments were recorded as a reduction to revenues; therefore, the lower payment in 2011 resulted in a net increase in revenues net of purchased power expense for 2011 compared to 2010.

*Volume—delivery*

Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, reflecting decreased average usage per residential and small commercial and industrial customer for 2011, compared to 2010.

*Weather—delivery*

The increase in revenues net of purchased power expense in 2011 compared to 2010 were partially offset by unfavorable weather conditions, despite setting a new record for highest daily peak load of 23,753 MWs on July 20, 2011. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions" because these weather conditions result in increased customer usage and delivery of electricity. Conversely, mild weather reduces demand.

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

| Heating and Cooling Degree-Days | 2011 | 2010 | Normal | % Change From 2010 | % Change From Normal |
|---|---|---|---|---|---|
| Twelve Months Ended December 31, | | | | | |
| Heating Degree-Days | 6,134 | 5,991 | 6,362 | 2.4% | (3.6)% |
| Cooling Degree-Days | 1,036 | 1,181 | 855 | (12.3)% | 21.2% |

*Uncollectible accounts recovery, net*

Represents recoveries under ComEd's uncollectible accounts tariff. Refer to uncollectible accounts expense discussion below for further information.

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

| | Increase (Decrease) |
|---|---|
| Weather—delivery | $ 89 |
| Uncollectible accounts recovery | 59 |
| Regulatory required programs cost recovery | 31 |
| Rate relief programs | 7 |
| 2007 City of Chicago settlement | 5 |
| Volume—delivery | (3) |
| Revenues subject to refund (2007 Rate Case) | (17) |
| Other | 17 |
| Total increase | $188 |

*Weather—delivery*

Revenues net of purchased power expense were higher in 2010 compared to 2009 due to favorable weather conditions. The changes in heating and cooling degree days in ComEd's service territory consisted of the following:

| Heating and Cooling Degree-Days | 2010 | 2009 | Normal | % Change From 2009 | % Change From Normal |
|---|---|---|---|---|---|
| Twelve Months Ended December 31, | | | | | |
| Heating Degree-Days | 5,991 | 6,429 | 6,362 | (6.8)% | (5.8)% |
| Cooling Degree-Days | 1,181 | 589 | 855 | 100.5% | 38.1% |

*Uncollectible accounts recovery*

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

*Regulatory required programs cost recovery*

Revenues related to regulatory required programs are the recoveries from customers of costs for various legislative and/or regulatory programs on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating and maintenance for regulatory required programs during the period presented. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

*Rate relief programs*

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

*2007 City of Chicago Settlement*

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

*Volume—delivery*

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

*Revenues subject to refund (2007 Rate Case)*

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

*Other*

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

***Operating and Maintenance Expense***

The changes in operating and maintenance expense for 2011 compared to 2010, consisted of the following:

| | Increase (Decrease) |
|---|---|
| Uncollectible accounts expense [(a)]: | |
| One-time impact of 2010 ICC Order [(b)] | $ 60 |
| Provision | 9 |
| Recovery, net [(c)] | (42) |
| | 27 |
| Labor, other benefits, contracting and materials | 72 |
| Storm-related costs | 70 |
| Accrued contribution to Science and Technology Innovation Trust [(d)] | 15 |
| Corporate allocations | 8 |
| Deferral of storm costs pursuant to EIMA, net of amortization [(d)] | (55) |
| Discrete impacts from 2010 Rate Case order [(e)] | (32) |
| Other | 6 |
| Increase in operating and maintenance expense | $111 |

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

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

(c) Represents impacts on recoveries under ComEd's uncollectible accounts tariff.

(d) Under EIMA, ComEd may recover costs associated with certain one-time events, such as large storms, over a five-year period. During the fourth quarter, ComEd recorded a net reduction in operating and maintenance expense for costs related to three significant 2011 storms. In addition, ComEd recorded an accrual in 2011, pursuant to EIMA, for a contribution to a new Science and Technology Innovation Trust fund that will be used to fund energy innovation.
(e) In May 2011, as a result of the 2010 Rate Case order, ComEd recorded one-time net benefits to reestablish previously expensed plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan.

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

| | Increase (Decrease) |
|---|---|
| Uncollectible accounts expense [(a)]: | |
| Amortization [(b)] | $ 59 |
| One-time impact of 2010 ICC Order [(c)] | (60) |
| Provision [(d)] | (37) |
| (Under) over-recovered | (3) |
| | (41) |
| Storm-related costs | 20 |
| Pension and non-pension postretirement benefits expense | 7 |
| Injuries and damages | 6 |
| Rider SMP regulatory asset write off [(e)] | 4 |
| Corporate allocations | (8) |
| Labor, other benefits, contracting and materials | (9) |
| ARO adjustment | (10) |
| 2009 restructuring plan severance charges | (19) |
| Other | (3) |
| Decrease in operating and maintenance expense | $(53) |

(a) On February 2, 2010, the ICC issued an order adopting ComEd's proposed tariffs filed in accordance with Illinois legislation providing public utilities the ability to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and amounts collected in rates annually through a rider mechanism starting with 2008 and prospectively.
(b) In 2010, ComEd recovered $59 million of operating revenues through its uncollectible accounts expense rider mechanism. An equal amount of amortization of regulatory assets was recorded in operating and maintenance expense. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.
(c) As a result of the February 2010 ICC order, ComEd recorded a regulatory asset of $70 million and an offsetting reduction in operating and maintenance expense for the cumulative under-collections in 2008 and 2009. In addition, ComEd recorded a one time contribution of $10 million associated with this legislation.
(d) Uncollectible accounts expense decreased in 2010 compared to 2009 as a result of ComEd's increased collection activities.
(e) In 2010, ComEd recorded a write off to operation and maintenance expense of the regulatory asset associated with the AMI pilot program of $4 million as a result of the September 30, 2010 Illinois Appellate Court ruling. In addition, ComEd recorded $5 million of operation and maintenance for regulatory required programs, and $2 million of depreciation expense associated with the AMI pilot program. In 2010, ComEd recorded $11 million of operating revenues associated with the AMI pilot program recovered under Rider SMP. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information on the Illinois Appellate Court ruling.

***Operating and maintenance expense for regulatory required programs***

Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

### *Depreciation and Amortization Expense*

The changes in depreciation and amortization expense for 2011 compared to 2010 and 2010 compared to 2009, consisted of the following:

| | Increase 2011 vs. 2010 | Increase 2010 vs. 2009 |
|---|---|---|
| Depreciation expense associated with higher plant balances [a] | $20 | $16 |
| Other | 6 | 6 |
| Increase in depreciation and amortization expense | $26 | $22 |

(a) Depreciation and amortization expense increased due to higher plant balances year over year.

### *Taxes Other Than Income*

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* Taxes other than income taxes increased primarily due to the accrual of estimated future refunds of Illinois utility distribution tax recorded in 2010 for the 2008 and 2009 tax years. Previously, ComEd had recorded refunds of the Illinois utility distribution tax when received. Due to sufficient, reliable evidence, ComEd began in June 2010 recording an estimated receivable associated with anticipated Illinois utility distribution tax refunds prospectively.

*Year Ended December 31, 2010 Compared to Year Ended December 31, 2009.* Taxes other than income taxes decreased, reflecting the accrual of estimated future refunds of Illinois utility distribution tax recorded in 2010 relating to prior tax years.

### *Interest Expense, Net*

The changes in interest expense, net for 2011 compared to 2010 and 2010 compared to 2009 consisted of the following:

| | Increase (Decrease) 2011 vs. 2010 | Increase (Decrease) 2010 vs. 2009 |
|---|---|---|
| Interest expense related to uncertain tax positions [a] | $(63) | $61 |
| Interest expense on debt (including financing trusts) [b] | 20 | 5 |
| Other | 2 | 1 |
| (Decrease) increase in interest expense, net | $(41) | $67 |

(a) During 2010, ComEd recorded $59 million of interest expense associated with the remeasurement of uncertain income tax positions related to the 1999 sale of Fossil Generating Assets.

(b) Interest expense on debt increased due to higher outstanding long-term debt balances year over year.

### *Other, Net*

The changes in other, net for 2011 compared to 2010 and 2010 compared to 2009 consisted of the following:

| | Increase (Decrease) 2011 vs. 2010 | Increase (Decrease) 2010 vs. 2009 |
|---|---|---|
| Interest income related to uncertain tax positions [a] | $ 8 | $(59) |
| Other-than-temporary impairment of investments | — | 7 |
| Other | (3) | (3) |
| Increase (decrease) in Other, net | $ 5 | $(55) |

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

***Effective Income Tax Rate***

ComEd's effective income tax rate for the years ended December 31, 2011, 2010, and 2009 was 37.5%, 51.4% and 38.0%, respectively. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

***ComEd Electric Operating Statistics and Revenue Detail***

| Retail Deliveries to customers (in GWhs) | 2011 | 2010 | % Change 2011 vs. 2010 | Weather-Normal % Change | 2009 | % Change 2010 vs. 2009 | Weather-Normal % Change |
|---|---|---|---|---|---|---|---|
| **Retail Delivery and Sales** (a) | | | | | | | |
| Residential | 28,273 | 29,171 | (3.1)% | (1.3)% | 26,621 | 9.6% | (1.2)% |
| Small commercial & industrial | 32,281 | 32,904 | (1.9)% | (0.8)% | 32,234 | 2.1% | (0.6)% |
| Large commercial & industrial | 27,732 | 27,717 | 0.1% | 0.6% | 26,668 | 3.9% | 2.6% |
| Public authorities & electric railroads | 1,235 | 1,273 | (3.0)% | (1.2)% | 1,237 | 2.9% | 2.4% |
| Total Retail | 89,521 | 91,065 | (1.7)% | (0.5)% | 86,760 | 5.0% | 0.2% |

| Number of Electric Customers | As of December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| Residential | 3,448,481 | 3,438,677 | 3,425,570 |
| Small commercial & industrial | 365,824 | 363,393 | 360,779 |
| Large commercial & industrial | 2,032 | 2,005 | 1,985 |
| Public authorities & electric railroads | 4,797 | 5,078 | 5,008 |
| Total | 3,821,134 | 3,809,153 | 3,793,342 |

| Electric Revenue | 2011 | 2010 | % Change 2011 vs. 2010 | 2009 | % Change 2010 vs. 2009 |
|---|---|---|---|---|---|
| **Retail Delivery and Sales** (a) | | | | | |
| Residential | $3,510 | $3,549 | (1.1)% | $3,115 | 13.9% |
| Small commercial & industrial | 1,517 | 1,639 | (7.4)% | 1,660 | (1.3)% |
| Large commercial & industrial | 383 | 397 | (3.5)% | 387 | 2.6% |
| Public authorities & electric railroads | 50 | 62 | (19.4)% | 57 | 8.8% |
| Total Retail | 5,460 | 5,647 | (3.3)% | 5,219 | 8.2% |
| Other Revenue (b) | 596 | 557 | 7.0% | 555 | 0.4% |
| Total Electric Revenues | $6,056 | $6,204 | (2.4)% | $5,774 | 7.4% |

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

(b) Other revenue primarily includes transmission revenue from PJM.

***Results of Operations—PECO***

| | 2011 | 2010 | Favorable (unfavorable) 2011 vs. 2010 variance | 2009 | Favorable (unfavorable) 2010 vs. 2009 variance |
|---|---|---|---|---|---|
| **Operating revenues** | $3,720 | $5,519 | $(1,799) | $5,311 | $ 208 |
| Purchased power and fuel expense | 1,864 | 2,762 | 898 | 2,746 | (16) |
| **Revenue net of purchased power and fuel expense** [(a)] | 1,856 | 2,757 | (901) | 2,565 | 192 |
| **Other operating expenses** | | | | | |
| Operating and maintenance | 725 | 680 | (45) | 640 | (40) |
| Operating and maintenance for regulatory required programs | 69 | 53 | (16) | — | (53) |
| Depreciation and amortization | 202 | 1,060 | 858 | 952 | (108) |
| Taxes other than income | 205 | 303 | 98 | 276 | (27) |
| Total other operating expenses | 1,201 | 2,096 | 895 | 1,868 | (228) |
| **Operating income** | 655 | 661 | (6) | 697 | (36) |
| **Other income and deductions** | | | | | |
| Interest expense, net | (134) | (193) | 59 | (187) | (6) |
| Loss in equity method investments | — | — | — | (24) | 24 |
| Other, net | 14 | 8 | 6 | 13 | (5) |
| Total other income and deductions | (120) | (185) | 65 | (198) | 13 |
| **Income before income taxes** | 535 | 476 | 59 | 499 | (23) |
| **Income taxes** | 146 | 152 | 6 | 146 | (6) |
| **Net income** | 389 | 324 | 65 | 353 | (29) |
| Preferred security dividends | 4 | 4 | — | 4 | — |
| **Net income on common stock** | $ 385 | $ 320 | $ 65 | $ 349 | $ (29) |

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

***Net Income***

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* The increase in net income was primarily driven by new distribution rates effective January 1, 2011 as a result of the 2010 electric and natural gas rate case settlements, decreased interest expense and decreased income tax expense. The increase in net income was partially offset by increased storm costs, increased depreciation expense and the net impact of the 2010 CTC recoveries reflected in electric operating revenues net of purchased power expense and CTC amortization expense, both of which ceased at the end of the transition period on December 31, 2010. The decreased interest expense related to the retirement of PETT transition bonds on September 1, 2010 and the impact of the change in measurement of uncertain tax positions in the second quarter of 2010. The decrease in income tax expense was primarily a result of the election of the safe harbor method of tax accounting for electric distribution property. See Note 11 of the Combined Notes to the Consolidated Financial Statements for further discussion of the election of the safe harbor method.

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

***Operating Revenues Net of Purchased Power and Fuel Expense***

There are certain drivers to operating revenue that are offset by their impact on purchased power and fuel expense, such as commodity procurement costs and customer choice programs. PECO's electric generation rates charged to customers were capped until December 31, 2010 in accordance with the 1998 restructuring settlement. Beginning January 1, 2011, PECO's electric generation rates are based on actual costs incurred through its approved competitive market procurement process. Electric and gas revenues and purchased power and fuel expenses are affected by fluctuations in commodity procurement costs. PECO's electric generation and natural gas cost rates charged to customers are subject to adjustments at least quarterly and are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with the PAPUC's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and gas revenues net of purchased power and fuel expenses.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the customer choice program. All PECO customers have the choice to purchase energy from a competitive electric generation supplier. The customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service. Customer choice program activity has no impact on net income. The number of retail customers purchasing energy from a competitive electric generation supplier was 387,600, 36,600 and 21,700 at December 31, 2011, 2010 and 2009, respectively, representing 25%, 2% and 1% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 57%, 1% and 1% of PECO's retail kWh sales for the years ended December 31, 2011, 2010 and 2009, respectively.

The changes in PECO's operating revenues net of purchased power and fuel expense for the year ended December 31, 2011 compared to the same period in 2010 consisted of the following:

| | Increase (Decrease) | | |
|---|---|---|---|
| | Electric | Gas | Total |
| Weather | $ (33) | $(13) | $ (46) |
| Volume | (11) | 3 | (8) |
| CTC recoveries | (995) | — | (995) |
| Regulatory program cost recovery | 17 | — | 17 |
| Pricing | 139 | 16 | 155 |
| Other | (29) | 5 | (24) |
| Total increase (decrease) | $(912) | $ 11 | $(901) |

*Weather*

The demand for electricity and gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. Electric and gas revenues net of purchased power and fuel expense were lower due to unfavorable weather conditions during 2011 in PECO's service territory compared to 2010 despite setting a new record for highest electric peak load of 8,983 MWs on July 22, 2011.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the year ended December 31, 2011 compared to the same period in 2010 and normal weather consisted of the following:

| | | | | % Change | |
|---|---|---|---|---|---|
| **Heating and Cooling Degree-Days** | **2011** | **2010** | **Normal** | **From 2010** | **From Normal** |
| Twelve Months Ended December 31, | | | | | |
| Heating Degree-Days | 4,157 | 4,396 | 4,638 | (5.4)% | (10.4)% |
| Cooling Degree-Days | 1,617 | 1,817 | 1,292 | (11.0)% | 25.2% |

*Volume*

The decrease in electric operating revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflected weak economic growth, the impact of energy efficiency initiatives on customer usage and the ramp-down of two oil refineries. See Note 2 of the Combined Notes to Consolidated Financial Statements for further information regarding energy efficiency initiatives.

The increase in gas operating revenues net of fuel expense related to delivery volume, exclusive of the effects of weather, reflected increased usage per customer across all customer classes.

*CTC Recoveries*

The decrease in electric revenues net of purchased power expense related to CTC recoveries reflected the absence of the CTC charge component that was included in rates charged to customers in 2010. PECO fully recovered all stranded costs during the final year of the transition period that expired on December 31, 2010.

*Regulatory Program Cost Recovery*

The increase in electric revenues net of purchased power expense relating to regulatory program cost recovery was due to increased recovery of costs associated with the energy efficiency and smart meter programs as well as administrative costs for the GSA and AEPS programs. The costs of these programs are recoverable from customers on a full and current basis through approved regulated rates and equal and offsetting expenses are included in operating and maintenance for regulatory required programs, depreciation and amortization expense, and income taxes.

*Pricing*

The increase in operating revenues net of purchased power and fuel expense as a result of pricing primarily reflected an increase of the new electric and natural gas distribution rates charged to customers that became effective January 1, 2011 in accordance with the 2010 PAPUC approved electric and natural gas distribution rate case settlements. See Note 2 of the Combined Notes to the Consolidated Financial Statements for further information.

*Other*

The decrease in electric operating revenues net of purchased power expense primarily reflected a decrease in GRT revenue as a result of lower supplied energy service and retail transmission revenues earned by PECO due to increased participation in the customer choice program. There is an equal and offsetting decrease in GRT expense included in taxes other than income. This decrease was partially offset by an increase in wholesale transmission revenue earned by PECO as a transmission owner for the use of PECO's transmission facilities in PJM. The rates charged for wholesale transmission are based on the prior year's peak, and the peak in 2010 was higher than in 2009.

The increase in gas operating revenues net of fuel expense primarily reflected an increase in off-system gas sales activity. Off-system gas sales revenues represent sales of excess gas supply on the wholesale market and the release of pipeline capacity.

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

| | Increase (Decrease) | | |
|---|---|---|---|
| | **Electric** | **Gas** | **Total** |
| Weather | $ 81 | $ (2) | $ 79 |
| CTC recoveries | 66 | — | 66 |
| Regulatory program cost recovery | 53 | — | 53 |
| Pricing | 12 | — | 12 |
| Other | (17) | (1) | (18) |
| Total increase (decrease) | $195 | $ (3) | $192 |

*Weather*

Electric revenues net of purchased power expense were higher due to favorable weather conditions during the summer months of 2010 in PECO's service territory. The increase was partially offset by lower gas revenues net of fuel expense primarily as a result of unfavorable weather conditions in the winters months of 2010 compared to 2009. The changes in heating and cooling degree days for the twelve months ended 2010 and 2009, consisted of the following:

| Heating and Cooling Degree-Days (a) | 2010 | 2009 | Normal | % Change From 2009 | % Change From Normal |
|---|---|---|---|---|---|
| Twelve Months Ended December 31, | | | | | |
| Heating Degree-Days | 4,396 | 4,534 | 4,638 | (3.0)% | (5.2)% |
| Cooling Degree-Days | 1,817 | 1,246 | 1,292 | 45.8% | 40.6% |

*CTC Recoveries*

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

*Regulatory Program Cost Recovery*

The increase in electric revenues relating to regulatory program cost recovery was due to the recovery of costs associated with the energy efficiency program and the consumer education program, respectively. The costs of these programs are recoverable from customers on a full and current basis through approved regulated rates and have been reflected in operating and maintenance expense for regulatory required programs during the period.

*Pricing*

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

*Other*

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

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

***Operating and Maintenance Expense***

The increase in operating and maintenance expense for 2011 compared to 2010 consisted of the following:

| | Increase (Decrease) |
|---|---|
| Labor, other benefits, contracting and materials | $26 |
| Storm-related costs | 13 |
| Uncollectible accounts expense | 4 |
| 2010 non-cash charge resulting from Health Care Legislation | (2) |
| Other | 4 |
| Increase in operating and maintenance expense | $45 |

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

| | Increase (Decrease) |
|---|---|
| Storm-related costs | $22 |
| Labor, other benefits, contracting and materials | 25 |
| Uncollectible accounts expense | (3) |
| Severance | (3) |
| Other | (1) |
| Increase in operating and maintenance expense | $40 |

***Operating and Maintenance for Regulatory Required Programs***

Operating and maintenance expense related to regulatory required programs for the years ended December 31, 2011 and 2010 consisted of costs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues during the current period. The increase in operating and maintenance expense for regulatory required programs for 2011 compared to 2010 and 2010 compared to 2009 consisted of the following:

| | Increase (Decrease) 2011 vs. 2010 | Increase (Decrease) 2010 vs. 2009 |
|---|---|---|
| Smart meter program | $ 9 | $— |
| EE&C program | 2 | 50 |
| GSA administrative costs | 5 | — |
| AEPS administrative costs | 1 | — |
| Consumer education program | (1) | 3 |
| Increase in operating and maintenance expense for regulatory required programs | $16 | $ 53 |

***Depreciation and Amortization Expense***

The changes in depreciation and amortization expense for 2011 compared to 2010 and 2010 compared to 2009 consisted of the following:

| | Increase (Decrease) 2011 vs. 2010 | Increase (Decrease) 2010 vs. 2009 |
|---|---|---|
| CTC amortization [(a)] | $(885) | $ 98 |
| Other | 27 | 10 |
| Increase (decrease) in depreciation and amortization expense | $(858) | $108 |

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

***Taxes Other Than Income***

The change in taxes other than income for 2011 compared to 2010 and 2010 compared to 2009 consisted of the following:

| | Increase (Decrease) 2011 vs. 2010 | Increase (Decrease) 2010 vs. 2009 |
|---|---|---|
| PURTA amortization | $ (4)[(a)] | $ 2[(b)] |
| GRT expense | (97)[(c)] | 22 |
| Other | 3 | 3 |
| Increase (decrease) in taxes other than income | $(98) | $27 |

(a) The decrease in taxes other than income related to PURTA amortization reflects the impact of regulatory liability amortization recorded in 2011 that offsets the distribution rate reduction made to refund a 2009 PURTA Supplemental Tax settlement to customers.

(b) The increase in taxes other than income related to PURTA amortization reflects the impact of regulatory liability amortization recorded in 2009 and 2008 that offsets the distribution rate reduction made to refund the 2007 PURTA settlement to customers.

(c) The decrease in GRT expense for 2011 compared to 2010 was a result of lower operating revenues.

### Interest Expense, Net

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* The decrease in interest expense, net for 2011 compared to 2010 was primarily due to decreased interest expense as a result of the retirement of PETT transition bonds on September 1, 2010 and the impact of interest expense incurred in June 2010 related to the change in measurement of uncertain tax positions in accordance with accounting guidance.

*Year Ended December 31, 2010 Compared to Year Ended December 31, 2009.* The increase in interest expense, net for 2010 compared to 2009 was primarily due to a change in measurement of uncertain tax positions in accordance with accounting guidance. The increase was partially offset by a decrease in interest expense resulting from the retirement of the PETT transition bonds on September 1, 2010.

See Notes 1 and 11 of the Combined Notes to Consolidated Financial Statements for further information.

### Loss in Equity Method Investments

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

### Other, Net

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010.* The increase in Other, net for 2011 compared to 2010 was primarily due to increased investment income and AFUDC—Equity. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional details of the components of Other, net.

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

### Effective Income Tax Rate

PECO's effective income tax rates for the years ended December 31, 2011, 2010 and 2009 were 27.3%, 31.9% and 29.3%, respectively. The decrease in effective income tax rate in 2011 compared to 2010 primarily related to the impact of electing the safe harbor method of tax accounting for electric distribution property. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

## *PECO Electric Operating Statistics and Revenue Detail*

| Retail Deliveries to customers (in GWhs) | 2011 | 2010 | % Change 2011 vs. 2010 | Weather-Normal % Change | 2009 | % Change 2010 vs. 2009 | Weather-Normal % Change |
|---|---|---|---|---|---|---|---|
| **Retail Delivery and Sales** (a) | | | | | | | |
| Residential | 13,687 | 13,913 | (1.6)% | 1.7% | 12,893 | 7.9% | 0.5% |
| Small commercial & industrial | 8,321 | 8,503 | (2.1)% | (0.7)% | 8,397 | 1.3% | (1.9)% |
| Large commercial & industrial | 15,677 | 16,372 | (4.2)% | (3.3)% | 15,848 | 3.3% | 0.8% |
| Public authorities & electric railroads | 945 | 925 | 2.2% | 4.6% | 930 | (0.5)% | (0.3)% |
| Total Electric Retail | 38,630 | 39,713 | (2.7)% | (0.9)% | 38,068 | 4.3% | 0.1% |

| Number of Electric Customers | As of December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| Residential | 1,415,681 | 1,411,643 | 1,404,416 |
| Small commercial & industrial | 157,137 | 156,865 | 156,305 |
| Large commercial & industrial | 3,110 | 3,071 | 3,094 |
| Public authorities & electric railroads | 1,122 | 1,102 | 1,085 |
| Total | 1,577,050 | 1,572,681 | 1,564,900 |

| Electric Revenue | 2011 | 2010 | % Change 2011 vs. 2010 | 2009 | % Change 2010 vs. 2009 |
|---|---|---|---|---|---|
| **Retail Delivery and Sales** (a) | | | | | |
| Residential | $1,934 | $2,069 | (6.5)% | $1,859 | 11.3% |
| Small commercial & industrial | 584 | 1,060 | (44.9)% | 1,034 | 2.5% |
| Large commercial & industrial | 304 | 1,362 | (77.7)% | 1,307 | 4.2% |
| Public authorities & electric railroads | 38 | 89 | (57.3)% | 90 | (1.1)% |
| Total Retail | 2,860 | 4,580 | (37.6)% | 4,290 | 6.8% |
| Other Revenue | 249 | 255 | (2.4)% | 259 | (1.5)% |
| Total Electric Revenues | $3,109 | $4,835 | (35.7)% | $4,549 | 6.3% |

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

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

## *PECO Gas Operating Statistics and Revenue Detail*

| Deliveries to customers (in mmcf) | 2011 | 2010 | % Change 2011 vs. 2010 | Weather-Normal % Change | 2009 | % Change 2010 vs. 2009 | Weather-Normal % Change |
|---|---|---|---|---|---|---|---|
| **Retail Delivery and Sales** (b) | | | | | | | |
| Retail sales | 54,239 | 56,833 | (4.6)% | 1.2% | 57,103 | (0.5)% | 0.9% |
| Transportation and other | 28,204 | 30,911 | (8.8)% | (7.5)% | 27,206 | 13.6% | 10.8% |
| **Total Gas Deliveries** | 82,443 | 87,744 | (6.0)% | (1.8)% | 84,309 | 4.1% | 4.1% |

| Number of Gas Customers | As of December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| Residential | 451,382 | 448,391 | 444,923 |
| Commercial & industrial | 41,373 | 41,303 | 40,991 |
| Total Retail | 492,755 | 489,694 | 485,914 |
| Transportation | 879 | 838 | 778 |
| Total | 493,634 | 490,532 | 486,692 |

| Gas revenue | 2011 | 2010 | % Change 2011 vs. 2010 | 2009 | % Change 2010 vs. 2009 |
|---|---|---|---|---|---|
| **Retail Delivery and Sales** [(a)] | | | | | |
| Retail sales | $575 | $656 | (12.3)% | $732 | (10.4)% |
| Transportation and other | 36 | 28 | 28.6% | 30 | (6.7)% |
| **Total Gas Deliveries** | $611 | $684 | (10.7)% | $762 | (10.2)% |

(a) Reflects delivery revenues and volumes from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. The cost of natural gas is charged to customers purchasing natural gas from PECO.

### Liquidity and Capital Resources

Exelon's 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. Exelon's 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 $0.5 billion, $5.3 billion, $1.0 billion and $0.6 billion, respectively. Additionally, Generation has access to a supplemental credit facility with an aggregate available commitment of $0.3 billion. The Registrant's credit facilities extend through March 2016 for Exelon, Generation and PECO and March 2013 for ComEd. Availability under the supplemental facility extends through December 2015 for $150 million of the $300 million commitment and March 2016 for the remaining $150 million. Exelon utilizes their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the "Credit Matters" section below for further discussion. Exelon expects cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon primarily uses their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. Exelon spends 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 delayed or limited and where such recovery takes place over an extended period of time. See Note 10 of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

#### *Proposed Merger Commitments*

As part of the application for approval of the merger by the MDPSC and related settlements, Exelon and Constellation have proposed a package of benefits to Baltimore Gas and Electric Company customers, the City of Baltimore and the State of Maryland, which results in a direct investment, including capital projects, in the State of Maryland of more than $1 billion. Exelon will evaluate the funding sources for these commitments at the time the specific investments or contributions are made. The funding may be through a combination of cash on the balance sheet, cash from operations or external financing. Of the $1 billion, Exelon estimates that approximately $150-200 million will be funded in 2012 with the remainder funded in 2013 and beyond. See Note 3 of the Combined Notes to Consolidated Financial Statements for further discussion of the proposed merger with Constellation.

### *Cash Flows from Operating Activities*

*General*

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

*Pension and Other Postretirement Benefits*

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. Exelon expects to contribute approximately $139 million to its pension plans in 2012, of which Generation, ComEd and PECO expect to contribute $60 million, $22 million and $16 million, respectively. Exelon contributed approximately $2.1 billion to its pension plans in January 2011 of which Generation, ComEd and PECO contributed $954 million, $873 million and $110 million, respectively. Exelon funded the $2.1 billion contribution with approximately $500 million from cash from operations, $750 million from the tax benefits of making the pension contributions and $850 million associated with the accelerated cash tax benefits from the 100% bonus depreciation provision enacted as part of the Tax Relief Act of 2010. Exelon contributed $766 million and $441 million to its pension plans in 2010 and 2009, respectively. See Note 13 of the Combined Notes to Consolidated Financial Statements for Exelon's 2011 and 2010 pension contributions.

Unlike the qualified pension plans, Exelon's other postretirement plans are not subject to regulatory minimum contribution requirements. Management considers several factors in determining the level of contributions to Exelon's other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued recovery). Exelon expects to contribute approximately $302 million to the other postretirement benefit plans in 2012, of which Generation, ComEd and PECO expect to contribute $132 million, $114 million and $34 million, respectively. Exelon contributed $277 million, $213 million and $167 million in 2011, 2010 and 2009, respectively. These amounts do not reflect Federal prescription drug subsidy payments received of $11 million, $10 million and $10 million in 2011, 2010 and 2009, respectively. See Note 13 of the Combined Notes to Consolidated Financial Statements for Exelon's 2011 and 2010 other postretirement benefit contributions.

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

*Tax Matters*

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

- In the third quarter of 2010, Exelon and IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions. Under the terms of the preliminary agreement, Exelon estimates that the IRS will assess tax and interest of approximately $300 million in 2012, and that Exelon will receive additional tax refunds of approximately $365 million between 2012 and 2014. In order to stop additional interest from accruing on the IRS expected assessment, Exelon made a payment in December 2010 to the IRS of $302 million. During 2010, Exelon and IRS Appeals failed to reach a settlement with respect to the like-kind exchange position and the related substantial understatement penalty. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding potential cash flows impacts of a fully successful IRS challenge to Exelon's like-kind exchange position.
- On August 19, 2011, the IRS issued Revenue Procedure 2011-43 that provides a safe harbor method of tax accounting for electric transmission and distribution property. ComEd intends to adopt the safe harbor in the Revenue Procedure in future periods as the associated tax cash benefits are received for the 2011 tax year. PECO adopted the safe harbor for the 2010 tax year. This change to the newly prescribed method will result in an initial cash tax benefit (primarily in 2011) at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million and $95 million, respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million. See Note 2 of the Combined Notes to Consolidated Financial Statements for discussion of the regulatory treatment prescribed in the 2010 electric distribution rate case settlement for PECO's cash tax benefit resulting from the application of the method change to years prior to 2010. The IRS anticipates issuing guidance in 2012 on the appropriate tax treatment of repair costs for gas distribution assets. Upon issuance of this guidance, PECO will assess its impact, and if it results in a cash benefit to Exelon, PECO will file a request for change in method of tax accounting for repair costs. PECO's approved 2010 natural gas distribution rate case settlement stipulates that the expected cash benefit resulting from the application of the new methodology to prior tax years must be refunded to customers over a seven-year period. The prospective tax benefit claimed as a result of the new methodology should be reflected in tax expense in the year in which it is claimed on the tax return and will be reflected in the determination of revenue requirements in the next natural gas distribution base rate case.
- The Tax Relief Act of 2010, enacted into law on December 17, 2010, includes provisions accelerating the depreciation of certain property for tax purposes. Qualifying property placed into service after September 8, 2010, and before January 1, 2012, is eligible for 100% bonus depreciation. Additionally, qualifying property placed into service during 2012 is eligible for

50% bonus depreciation. These provisions will generate approximately $1.1 billion of cash for Exelon (approximately $850 million in 2011 and approximately $300 million in 2012). The cash generated is an acceleration of tax benefits that Exelon would have otherwise received over 20 years. Additionally, while the capital additions at ComEd and PECO generally increase future revenue requirements, the bonus depreciation associated with these capital additions will partially mitigate any future rate increases through the ratemaking process. See the "Pension and Other Postretirement Benefits" section above for further details regarding the use of the cash generated under the Tax Relief Act of 2010.

- Given the current economic environment, state and local governments are facing increasing financial challenges, which may increase the risk of additional income tax levies, property taxes, and other taxes. See Note 11 of the Combined Notes to Consolidated Financial Statements for further details regarding the 2011 Illinois State Tax Rate Legislation, which increases the corporate income tax rate in Illinois.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the years ended December 31, 2011, 2010 and 2009:

| | 2011 | 2010 | 2011 vs. 2010 Variance | 2009 | 2010 vs. 2009 Variance |
|---|---|---|---|---|---|
| Net income | $ 2,495 | $2,563 | $ (68) | $2,707 | $(144) |
| Add (subtract): | | | | | |
| Non-cash operating activities [(a)] | 4,848 | 4,340 | 508 | 3,930 | 410 |
| Pension and non-pension postretirement benefit contributions | (2,360) | (959) | (1,401) | (588) | (371) |
| Income taxes | 492 | (543) | 1,035 | (29) | (514) |
| Changes in working capital and other noncurrent assets and liabilities [(b)] | (275) | 122 | (397) | (82) | 204 |
| Option premiums paid, net | (3) | (124) | 121 | (40) | (84) |
| Counterparty collateral received (paid), net | (344) | (155) | (189) | 196 | (351) |
| Net cash flows provided by operations | $ 4,853 | $5,244 | $ (391) | $6,094 | $(850) |

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

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

Cash flows provided by operations for 2011, 2010 and 2009 by Registrant were as follows:

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Exelon | $4,853 | $5,244 | $6,094 |
| Generation | 3,313 | 3,032 | 3,930 |
| ComEd | 836 | 1,077 | 1,020 |
| PECO | 818 | 1,150 | 1,166 |

Changes in Exelon's, Generation's, ComEd's and PECO's cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business. In addition, significant operating cash flow impacts for the Registrants for 2011, 2010 and 2009 were as follows:

*Generation*

- During 2011, 2010 and 2009, Generation had net (payments) receipts of counterparty collateral of $(410) million, $(1) million and $195 million, respectively. Net payments during 2011 and 2010 were primarily due to market conditions that resulted in changes to Generation's net mark-to-market position. Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted or collected from its counterparties. This collateral may be in various forms, such as cash, which may be obtained through the issuance of commercial paper, or letters of credit.
- During 2007, Generation, along with ComEd and other generators and utilities, reached an agreement with various representatives from the State of Illinois to address concerns about higher electric bills in Illinois. Generation committed to

contributing approximately $747 million over four years. As part of the agreement, Generation contributed cash of approximately $23 million in 2010 and $118 million in 2009. As of December 31, 2010, Generation had fulfilled its commitments under the Illinois Settlement Legislation.

- During 2011, 2010 and 2009, Generation's accounts receivable from ComEd increased (decreased) by $12 million, $(65) million and $(28) million, respectively, primarily due to changes in receivables for energy purchases related to its SFC, ICC-approved RFP contracts and financial swap contract.
- During 2011, 2010 and 2009, Generation's accounts receivable from PECO primarily due to the PPA increased (decreased) by $(210) million, $74 million and $48 million, respectively.
- During 2011, 2010 and 2009, Generation had net payments of approximately $3 million, $124 million and $40 million, respectively, related to purchases and sales of options. The level of option activity in a given year may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

*ComEd*

- During 2011, 2010 and 2009, ComEd's net payables to Generation for energy purchases related to its supplier forward contract, ICC-approved RFP contracts and financial swap contract settlements increased (decreased) by $12 million, $(65) million and $(28) million, respectively. During 2011, 2010 and 2009, ComEd's payables to other energy suppliers for energy purchases increased (decreased) by $(43) million, $58 million and $(68) million, respectively.
- During 2011 and 2010, ComEd received $63 million and posted $153 million, respectively, of incremental cash collateral with PJM due to seasonal variations in its energy transmission activity levels. As of December 31, 2011 and December 31, 2010, ComEd had $90 million and $153 million of cash collateral remaining at PJM. Prior to the second quarter of 2010, ComEd used letters of credit to cover all PJM collateral requirements.

*PECO*

- During 2011, 2010 and 2009, PECO's payables to Generation for energy purchases increased (decreased) by $(210) million, $74 million and $48 million, respectively, and payables to other energy suppliers for energy purchases increased (decreased) by $97 million, $1 million and $(43) million, respectively. PECO's decrease in payables to Generation and increase in payables to other energy suppliers in 2011 is due to the expiration of the PPA with Generation on December 31, 2010.

### *Cash Flows from Investing Activities*

Cash flows used in investing activities for 2011, 2010, and 2009 by Registrant were as follows:

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Exelon (a)(b)(d) | $(4,603) | $(3,894) | $(3,458) |
| Generation (a)(d) | (3,077) | (2,896) | (2,220) |
| ComEd | (1,007) | (939) | (821) |
| PECO (b) | (557) | (120) | (377) |

Capital expenditures by Registrant for 2011, 2010 and 2009 and projected amounts for 2012 are as follows:

| | Projected 2012 (c) | 2011 | 2010 | 2009 |
|---|---|---|---|---|
| Generation (d) | $3,768 | $2,491 | $1,883 | $1,977 |
| ComEd (e) | 1,330 | 1,028 | 962 | 854 |
| PECO | 436 | 481 | 545 | 388 |
| Other (f) | 48 | 42 | (64) | 54 |
| Total Exelon capital expenditures | $5,582 | $4,042 | $3,326 | $3,273 |

(a) Includes $387 million in 2011 related to acquisitions, principally acquisition of Wolf Hollow, Antelope Valley and Shooting Star; and $893 million in 2010, related to the acquisition of Exelon Wind. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

(b) Includes a cash inflow of $413 million in 2010 as a result of the consolidation of PETT on January 1, 2010. See Note 1 of the Combined Notes to Consolidated Financial Statements for additional information.
(c) The projected capital expenditures do not include adjustments for non-cash activity.
(d) Includes nuclear fuel.
(e) The projected capital expenditures include $233 million in incremental spending related to ComEd's 2012 investment plan filed with the ICC on January 6, 2012. Pursuant to EIMA, under which ComEd has committed to invest approximately $2.6 billion over the next ten years to modernize and storm-harden its distribution system and to implement smart grid technology.
(f) Other primarily consists of corporate operations and BSC. The negative capital expenditures for Other in 2010 primarily relate to the transfer of information technology hardware and software assets from BSC to Generation, ComEd and PECO.

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

*Generation*

Approximately 34% and 31% of the projected 2012 capital expenditures at Generation are for investments in renewable energy generation, including Antelope Valley and Exelon Wind construction costs; and the acquisition of nuclear fuel, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Also included in the projected 2012 capital expenditures are a portion of the costs of a series of planned power uprates across Generation's nuclear fleet. See "Executive Overview" for more information on nuclear uprates.

*ComEd and PECO*

Approximately 80% and 69% of the projected 2012 capital expenditures at ComEd and PECO, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA and ComEd and PECO's construction commitments under PJM's RTEP. The remaining amounts are for capital additions to support new business and customer growth, which for ComEd includes capital expenditures related to smart grid/smart meter technology required under EIMA and for PECO includes capital expenditures related to its smart meter program and SGIG project, net of DOE expected reimbursements. See Notes 2 and 5 of the Combined Notes to Consolidated Financial Statements for additional information.

In 2010, NERC provided guidance to transmission owners that recommends ComEd and PECO perform assessments of all their transmission lines, with the highest priority lines assessed by December 31, 2011, medium priority lines by December 31, 2012, and the lowest priority lines by December 31, 2013. In compliance with this guidance, ComEd and PECO submitted their most recent bi-annual reports to NERC in January 2012. ComEd and PECO will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's and PECO's forecasted 2012 capital expenditures above reflect capital spending for remediation pursuant to the assessments completed as of December 31, 2011.

ComEd and PECO anticipate that they will fund capital expenditures with internally generated funds and borrowings, including ComEd's capital expenditures associated with EIMA as further discussed in Note 2 of the Combined Notes to Consolidated Financial Statements.

***Cash Flows from Financing Activities***

Cash flows provided by (used in) financing activities for 2011, 2010 and 2009 by Registrant were as follows:

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Exelon | $(846) | $(1,748) | $(1,897) |
| Generation | (196) | (779) | (1,746) |
| ComEd | 355 | (179) | (155) |
| PECO | (589) | (811) | (525) |

***Debt.*** Debt activity for 2011, 2010 and 2009 by Registrant was as follows:

| Company | Issuances of long-term debt in 2011 | Use of proceeds |
|---|---|---|
| ComEd | $600 million of First Mortgage 1.625% Bonds, Series 110, due January 15, 2014 | Used as an interim source of liquidity for a January 2011 contribution to Exelon-sponsored pension plans. |
| ComEd | $250 million of First Mortgage 1.95% Bonds, Series 111, due September 1, 2016 | Used to retire $191 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, E, and F, retire $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes. |
| ComEd | $350 million of First Mortgage 3.40% Bonds, Series 112, due September 1, 2021 | Used to retire $191 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, E, and F, retire $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes. |

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

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

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

| Company | Retirement of long-term debt in 2011 |
|---|---|
| Generation | $2 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020 |
| ComEd | $2 million of 4.75% sinking fund debentures, due December 1, 2011 |
| ComEd | $50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, due March 1, 2020 |
| ComEd | $50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 E, due May 1, 2021 |
| ComEd | $91 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 F, due March 1, 2017 |
| ComEd | $345 million of 5.40% First Mortgage Bonds, Series 105, due December 15, 2011 |
| PECO | $250 million of 5.95% First and Refunding Mortgage Bonds, due November 1, 2011 |

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

| Company | Retirement of long-term debt in 2009 |
|---|---|
| Exelon Corporate | $500 million of 6.75% Senior Notes, due May 1, 2011 |
| Generation | $700 million of 6.95% Senior Notes, due June 15, 2011 |
| Generation | $46 million of Pollution Control Notes with variable interest rates, due December 1, 2042 [a] |
| Generation | $51 million of Pollution Control Notes with variable interest rates, due April 1, 2021 |
| Generation | $39 million of Pollution Control Notes with variable interest rates, due April 1, 2021 |
| Generation | $30 million of Pollution Control Notes with variable interest rates, due December 1, 2029 |
| Generation | $92 million of Pollution Control Notes with variable interest rates, due October 1, 2030 |
| Generation | $69 million of Pollution Control Notes with variable interest rates, due October 1, 2030 |
| Generation | $14 million of Pollution Control Notes with variable interest rates, due October 1, 2034 |
| Generation | $13 million of Pollution Control Notes with variable interest rates, due October 1, 2034 |
| Generation | $10 million of 6.33% notes payable, due August 8, 2009 |
| Generation | $1 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020 |
| ComEd | $91 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 F, due March 1, 2017 [b] |

| Company | Retirement of long-term debt in 2011 |
|---|---|
| ComEd | $50 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, due March 1, 2020 (b) |
| ComEd | $50 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 E, due May 21, 2021 (b) |
| ComEd | $16 million of 5.70% First Mortgage Bonds, Series 1994 B, due January 15, 2009 |
| ComEd | $1 million of 4.625-4.75% sinking fund debentures, due at various dates |
| PECO | $319 million of 7.65% PETT Transition Bonds, due September 1, 2009 |
| PECO | $390 million of 6.52% PETT Transition Bonds, due September 1, 2010 |

(a) Repurchased due to a failed remarketing and remarketed in February 2009.

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

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

***Dividends.*** Cash dividend payments and distributions during 2011, 2010 and 2009 by Registrant were as follows:

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Exelon | $1,393 | $1,389 | $1,385 |
| Generation | 172 | 1,508 | 2,276 |
| ComEd | 300 | 310 | 240 |
| PECO | 352 | 228 | 316 |

***First Quarter 2012 Dividend.*** On October 25, 2011, the Exelon Board of Directors declared a first quarter 2012 regular quarterly dividend of $0.525 per share on Exelon's common stock payable on March 9, 2012, to shareholders of record of Exelon at the end of the day on February 15, 2012.

***Second Quarter 2012 Dividend.*** In addition, on January 24, 2012, the Exelon Board of Directors declared a second quarter 2012 regular quarterly dividend of $0.525 per share on Exelon's common stock contingent on the pending merger with Constellation. If the effective date of the merger is after May 15, 2012, the Board of Directors declared a regular quarterly dividend of $0.525 per share on Exelon's common stock, payable on June 8, 2012, to shareholders of record of Exelon at the end of the day on May 15, 2012.

If the effective date of the merger is on or before May 15, 2012, shareholders will receive two separate dividend payments totaling $0.525 per share:

- The first of the dividend payments will be pro-rated, with shareholders of record as of the end of day before the effective date of the merger receiving $0.00583 per share per day for the period from and including February 16, 2012, the day after the record date for the previous dividend, through and including the day before the effective date of the merger. This portion of the dividend will be paid within 30 days after the effective date of the merger.
- The second of the dividend payments will also be pro-rated, with all Exelon shareholders, including the former Constellation shareholders, of record at the end of the day on May 15, 2012, receiving $0.00583 per share per day for the period from and including the effective date of the merger through and including May 15, 2012. This portion of the dividend will be paid on June 8, 2012.

**Short-Term Borrowings.** Short-term borrowings incurred (repaid) during 2011, 2010 and 2009 by Registrant were as follows:

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| ComEd | $— | $(155) | $ 95 |
| PECO | — | — | (95) |
| Other (a) | 161 | — | (56) |
| Exelon | $161 | $(155) | $(56) |

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

***Retirement of Long-Term Debt to Financing Affiliates.*** Retirement of long-term debt to financing affiliates during 2011, 2010 and 2009 by Registrant were as follows:

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Exelon | $— | $— | $709 |
| PECO | — | — | 709 |

***Other.*** Other significant financing activities for Exelon for 2011, 2010 and 2009 were as follows:

- Exelon received proceeds from employee stock plans of $38 million, $48 million and $42 million during 2011, 2010 and 2009, respectively.

***Credit Matters***

*Market Conditions*

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large diversified credit facilities. The credit facilities include $7.7 billion in aggregate total commitments of which $6.8 billion was available as of December 31, 2011, and of which no financial institution has more than 10% of the aggregate commitments for Exelon, Generation, ComEd and PECO. The Registrants had access to the commercial paper market during 2011 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels, and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A Risk Factors of Exelon's 2011 Form 10-K for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flows from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of December 31, 2011, it would have been required to provide incremental collateral of approximately $1,819 million, which is well within its current available credit facility capacities of approximately $4.7 billion. The $1,819 million includes $1,612 million of collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements and $207 million of financial assurances that Generation would be required to provide NEIL related to annual retrospective premium obligations. If ComEd lost its investment grade credit rating as of December 31, 2011, it would have been required to provide incremental collateral of approximately $227 million, which is well within its current available credit facility capacity of approximately $1.0 billion. If PECO lost its investment grade credit rating as of December 31, 2011, it would have been required to provide collateral of $1 million pursuant to PJM's credit policy and could have been required to provide collateral of approximately $54 million related to its natural gas procurement contracts, which, in the aggregate, is well within PECO's current available credit facility capacity of approximately $600 million.

*Exelon Credit Facilities*

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

*Other Credit Matters*

***Capital Structure.*** At December 31, 2011, the capital structures of the Registrants consisted of the following:

| | Exelon | Generation | ComEd | PECO |
|---|---|---|---|---|
| Long-term debt | 45% | 30% | 44% | 37% |
| Long-term debt to affiliates (a) | 2 | — | 2 | 3 |
| Common equity | 52 | — | 54 | 54 |
| Member's equity | — | 70 | — | — |
| Preferred securities | — | — | — | 2 |
| Commercial paper and notes payable | 1 | — | — | 4 |

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

***Shelf Registration Statements.*** Each of the Registrants has a current shelf registration statement effective with the SEC that provides for the sale of unspecified amounts of securities. The ability of each Registrant to sell securities off its shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

***Regulatory Authorizations.*** The issuance by ComEd and PECO of long-term debt or equity securities requires the prior authorization of the ICC and PAPUC, respectively. ComEd and PECO normally obtain the required approvals on a periodic basis to cover their anticipated financing needs for a period of time or in connection with a specific financing. As of December 31, 2011, ComEd had $41 million in long-term debt refinancing authority from the ICC and $456 million in new money long-term debt financing authority. As of December 31, 2011, PECO had $1.9 billion in long-term debt financing authority from the PAPUC.

FERC has financing jurisdiction over ComEd's and PECO's short-term financings and all of Generation's financings. As of December 31, 2011, ComEd and PECO had short-term financing authority from FERC that expires on December 31, 2013 of $2.5 billion and $1.5 billion, respectively. Generation currently has blanket financing authority that it received from FERC in connection with its market-based rate authority. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Exelon's ability to pay dividends on its common stock depends on the receipt of dividends paid 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, 2011, Exelon had retained earnings of $10,055 million, including Generation's undistributed earnings of $4,232 million, ComEd's retained earnings of $447 million consisting of retained earnings appropriated for future dividends of $2,086 million partially offset by $1,639 million of unappropriated retained deficit, and PECO's retained earnings of $559 million. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

## Contractual Obligations and Off-Balance Sheet Arrangements

The following tables summarizes Exelon's future estimated cash payments as of December 31, 2011 under existing contractual obligations, including payments due by period. See Note 18 of the Combined Notes to Consolidated Financial Statements for information regarding Exelon's commercial and other commitments, representing commitments potentially triggered by future events.

*Exelon*

| | | Payment due within | | | | |
|---|---|---|---|---|---|---|
| | Total | 2012 | 2013-2014 | 2015-2016 | Due 2017 and beyond | All Other |
| Long-term debt [(a)] | $13,000 | $ 825 | $1,919 | $1,725 | $ 8,531 | $— |
| Interest payments on long-term debt [(b)] | 8,454 | 663 | 1,197 | 1,023 | 5,571 | — |
| Liability and interest for uncertain tax positions [(c)] | 191 | 1 | — | — | — | 190 |
| Capital leases | 34 | 3 | 6 | 7 | 18 | — |
| Operating leases [(d)] | 669 | 72 | 118 | 92 | 387 | — |
| Purchase power obligations [(e)] | 922 | 188 | 134 | 122 | 478 | — |
| Fuel purchase agreements [(f)] | 8,722 | 1,491 | 2,092 | 1,870 | 3,269 | — |
| Electric supply procurement [(f)] | 682 | 469 | 193 | 20 | — | — |
| REC and AEC purchase commitments [(f)] | 15 | 3 | 5 | 2 | 5 | — |
| Curtailment services commitments [(f)] | 13 | 13 | — | — | — | — |
| Long-term renewable energy and REC commitments [(g)] | 1,692 | 36 | 142 | 153 | 1,361 | — |
| Other purchase obligations [(h)] [(i)] | 595 | 282 | 232 | 66 | 15 | — |
| City of Chicago agreement—2003 [(j)] | 6 | 6 | — | — | — | — |
| Spent nuclear fuel obligation | 1,019 | — | — | — | 1,019 | — |
| Pension minimum funding requirement [(k)] | 1,950 | 96 | 239 | 1,352 | 263 | — |
| Total contractual obligations | $37,964 | $4,148 | $6,277 | $6,432 | $20,917 | $190 |

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

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2011 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, 2011. Includes estimated interest payments due to ComEd and PECO financing trusts.

(c) As of December 31, 2011, Exelon's liability for uncertain tax positions and related net interest payable were $191 million and $10 million, respectively. Exelon was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. Exelon has other unrecognized tax positions that were not recorded on the Consolidated Balance Sheets in accordance with authoritative guidance. See Note 11 of the Combined Notes to Consolidated Financial Statements for further information regarding unrecognized tax positions.

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

(e) Purchase power obligations include PPAs and other capacity contracts that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2011. Expected payments include certain capacity charges that are contingent on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. These obligations do not include ComEd's SFCs as these contracts do not require purchases of fixed or minimum quantities. See Notes 2 and 18 of the Combined Notes to Consolidated Financial Statements.

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

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

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

(i) Excludes obligations associated with the January 25, 2012 materials agreement between ComEd and Silver Springs Network, Inc. (Silver Spring) by which Silver Spring will deliver a smart grid platform to ComEd's system. ComEd has the right to terminate the agreement upon written notice to Silver Spring if ComEd fails to obtain required regulatory approvals, including ICC approval of ComEd's AMI Deployment Plan associated with EIMA.

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

(k) These amounts represent Exelon's estimated minimum pension contributions to its qualified plans required under ERISA and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2016 are currently not reliably estimable. See Note 13 of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

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

For additional information regarding:

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

## QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

### Commodity Price Risk

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

#### *Generation*

***Normal Operations and Hedging Activities.*** Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of ComEd's and PECO's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into physical contracts as well as financial derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges, including the ComEd financial swap contract, will occur during 2012 through 2014. Generation's energy contracts are accounted for under the accounting guidance for derivatives as further discussed in Note 9 of the Combined Notes to Consolidated Financial Statements.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Generation hedges commodity risk on a ratable basis over the three years leading to the spot market. As of December 31, 2011, the percentage of expected generation hedged was 88%-91%, 61%-64% and 32%-35% for 2012, 2013 and 2014, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include cash flow hedges, other derivatives and certain non-derivative contracts including sales to ComEd and PECO to serve their retail load.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's non-trading portfolio associated with a $5 reduction in the annual average Ni-Hub and PJM-West around-the-clock energy price based on December 31, 2011 market conditions and hedged position would be a decrease in pre-tax net income of approximately $45 million, $289 million and $535 million, respectively, for 2012, 2013 and 2014. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

***Proprietary Trading Activities.*** Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into purely to profit from market price changes as opposed to hedging an exposure and is subject to limits established by Exelon's RMC. The trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 5,742 GWh, 3,625 GWh and 7,578 GWh for the years ended December 31, 2011, 2010 and 2009 respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Trading portfolio activity for the year ended December 31, 2011 resulted in pre-tax gains of $24 million due to net mark-to-market losses of $3 million and realized gains of $27 million. Generation uses a 95% confidence interval, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $80,000 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, 2011 of $6,858 million, Generation has not segregated proprietary trading activity in the following tables.

***Fuel Procurement.*** Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained primarily through long-term contracts for uranium concentrates, and long-term contracts for conversion services, enrichment services and fuel fabrication services. The supply markets for coal, natural gas, uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 55% of Generation's uranium concentrate requirements from 2012 through 2016 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information regarding uranium and coal supply agreement matters.

***ComEd***

The financial swap contract between Generation and ComEd was deemed prudent by the Illinois Settlement Legislation, thereby ensuring that ComEd will be entitled to receive full cost recovery in rates. The change in fair value each period is recorded by ComEd with an offset to a regulatory asset or liability. This financial swap contract between Generation and ComEd expires on May 31, 2013.

ComEd's RFP contracts are deemed to be derivatives that qualify for the normal purchases and normal sales exception under derivative accounting guidance. ComEd does not enter into derivatives for speculative or trading purposes.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. Delivery under these contracts begins in June 2012. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Notes 2 and 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

***PECO***

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

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

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

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

The following table provides detail on changes in Exelon's, Generation's, ComEd's and PECO's mark-to-market net asset or liability balance sheet position from January 1, 2010 to December 31, 2011. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings, as well as the settlements from OCI to earnings and changes in fair value for the hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts. For additional information on the cash flow hedge gains and losses included within accumulated OCI and the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2011 and December 31, 2010 refer to Note 9 of the Combined Notes to Consolidated Financial Statements.

| | Generation | ComEd | PECO | Intercompany Eliminations (g) | Exelon |
|---|---|---|---|---|---|
| Total mark-to-market energy contract net assets (liabilities) at January 1, 2010 (a) | $ 1,769 | $(971) | $ (4) | $ — | $ 794 |
| Total change in fair value during 2010 of contracts recorded in result of operations | 415 | — | — | — | 415 |
| Reclassification to realized at settlement of contracts recorded in results of operations | (328) | — | — | — | (328) |
| Ineffective portion recognized in income (b) | 1 | — | — | — | 1 |
| Reclassification to realized at settlement from accumulated OCI (c) | (1,125) | — | — | 371 | (754) |
| Effective portion of changes in fair value—recorded in OCI (d) | 883 | — | — | (378) | 505 |
| Changes in fair value—energy derivatives (e) | — | — | (5) | 7 | 2 |
| Changes in collateral | (4) | — | — | — | (4) |
| Changes in net option premium paid/(received) | 124 | — | — | — | 124 |
| Other income statement reclassifications (f) | 73 | — | — | — | 73 |
| Other balance sheet reclassifications | (5) | — | — | — | (5) |
| Total mark-to-market energy contract net assets (liabilities) at December 31, 2010 (a) | $ 1,803 | $(971) | $ (9) | $ — | $ 823 |
| Total change in fair value during 2011 of contracts recorded in result of operations | 241 | — | — | — | 241 |
| Reclassification to realized at settlement of contracts recorded in results of operations | (541) | — | — | — | (541) |
| Ineffective portion recognized in income (b) | 9 | — | — | — | 9 |
| Reclassification to realized at settlement from accumulated OCI (c) | (968) | — | — | 456 | (512) |
| Effective portion of changes in fair value—recorded in OCI (d) | 827 | — | — | (170) | 657 |
| Changes in fair value—energy derivatives (e) | — | 171 | 9 | (286) | (106) |
| Changes in collateral | 411 | — | — | — | 411 |
| Changes in net option premium paid/(received) | 3 | — | — | — | 3 |
| Other income statement reclassifications (f) | (137) | — | — | — | (137) |
| Other balance sheet reclassifications | — | — | — | — | — |
| Total mark-to-market energy contract net assets (liabilities) at December 31, 2011 (a) | $ 1,648 | $(800) | $— | $ — | $ 848 |

(a) Amounts are shown net of collateral paid to and received from counterparties.

(b) For Generation, reflects $9 million and $1 million of changes in cash flow hedge ineffectiveness, of which none was related to Generation's financial swap contract with ComEd or Generation's block contracts with PECO for the years ended December 31, 2011 and 2010, respectively.

(c) For Generation, includes $451 million and $371 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the years ended December 31, 2011 and 2010, respectively, and $5 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlements of the PECO block contracts for the year ended December 31, 2011.

(d) For Generation, includes $170 million and $375 million of gains related to the changes in fair value of the five-year financial swap with ComEd for the years ended December 31, 2011 and 2010, respectively, and $3 million of gains related to the changes in fair value of the block contracts with PECO for the year ended December 31, 2010. The PECO block contracts were designated as normal sales as of May 31, 2010. As such, no additional changes in the fair value of PECO's block contracts were recorded and the mark-to-market balances previously recorded were amortized over the terms of the contracts, which ended December 31, 2011.

(e) For ComEd and PECO, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2011 and 2010, ComEd recorded a regulatory asset of $800 million and $975 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of December 31, 2010, ComEd also had a regulatory liability of $4 million related to mark-to-market derivative assets with unaffiliated suppliers. During 2011 and 2010, this includes $170 million and $375 million of decreases in fair value, respectively, and $451 million and $371 million of realized gains, respectively, due to settlements of ComEd's five-year financial swap with Generation. During 2011 and 2010 ComEd also recorded a $110 million decrease and a $4 million increase, respectively, in fair value associated with floating-to-fixed energy swap contracts with unaffiliated suppliers. As of December 31, 2010, PECO recorded a regulatory asset of $9 million related to its mark-to-market derivative liabilities. During the year ended December 31, 2010, PECO's change included $3 million related to the change in fair value of PECO's block contracts with Generation. PECO's block contracts were designated as normal sales as of May 31, 2010 and, as such, no additional changes in the fair value of PECO's block contracts were recorded. During the year ended December 31, 2011, PECO's mark-to-market derivative liability was fully amortized, including $5 million related to PECO's block contracts with Generation, in accordance with the terms of the contracts.

(f) Includes $137 million and $73 million of amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of the underlying transactions for the years ended December 31, 2011 and 2010, respectively.

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

### *Fair Values*

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

### *Exelon*

| | Maturities Within | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 and Beyond | Total Fair Value |
| *Normal Operations, qualifying cash flow hedge contracts* (a)(c): | | | | | | | |
| Prices provided by external sources | $339 | $246 | $ 99 | $ 1 | $— | $— | $685 |
| Total | $339 | $246 | $ 99 | $ 1 | $— | $— | $685 |
| *Normal Operations, other derivative contracts* (b)(c): | | | | | | | |
| Actively quoted prices | $ (1) | $— | $— | $— | $— | $— | $ (1) |
| Prices provided by external sources | (84) | 88 | 111 | 32 | — | — | 147 |
| Prices based on model or other valuation methods (d) | 67 | 13 | (5) | (1) | (11) | (46) | 17 |
| Total | $ (18) | $101 | $106 | $ 31 | $(11) | $(46) | $163 |

(a) Mark-to-market gains and losses on contracts that qualify as cash flow hedges are recorded in OCI.

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

(c) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $540 million at December 31, 2011.

(d) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

***Generation***

| | Maturities Within | | | | | | |
|---|---|---|---|---|---|---|---|
| | **2012** | **2013** | **2014** | **2015** | **2016** | **2017 and Beyond** | **Total Fair Value** |
| *Normal Operations, qualifying cash flow hedge contracts [(a)(c)]:* | | | | | | | |
| Prices provided by external sources | $339 | $246 | $ 99 | $ 1 | $— | $— | $ 685 |
| Prices based on model or other valuation methods | 503 | 191 | — | — | — | — | 694 |
| Total | $842 | $437 | $ 99 | $ 1 | $— | $— | $1,379 |
| *Normal Operations, other derivative contracts [(b)(c)] :* | | | | | | | |
| Actively quoted prices | $ (1) | $— | $— | $— | $— | $— | $ (1) |
| Prices provided by external sources | (84) | 88 | 111 | 32 | — | — | 147 |
| Prices based on model or other valuation methods | 76 | 29 | 9 | 10 | (1) | — | 123 |
| Total | $ (9) | $117 | $120 | $ 42 | $ (1) | $— | $ 269 |

(a) Mark-to-market gains and losses on contracts that qualify as cash flow hedges are recorded in OCI. Amounts include a $694 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 (and offset against mark-to-market assets and liabilities) of $540 million at December 31, 2011.

***ComEd***

| | Maturities Within | | | | | | |
|---|---|---|---|---|---|---|---|
| | **2012** | **2013** | **2014** | **2015** | **2016** | **2017 and Beyond** | **Fair Value** |
| Prices based on model or other valuation methods [(a)] | $(512) | $(207) | $(14) | $(11) | $(10) | $(46) | $(800) |

(a) Represents ComEd's net assets (liabilities) associated with the five-year financial swap with Generation and the floating-to-fixed energy swap contracts with unaffiliated suppliers.

**Credit Risk, Collateral, and Contingent Related Features**

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

### *Generation*

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2011. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs and NYMEX and ICE commodity exchanges, which are discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd and PECO of $70 million and $39 million, respectively. See Note 21 of the Combined Notes to Consolidated Financial Statements for further information.

| Rating as of December 31, 2011 | 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 | $1,581 | $351 | $1,230 | 1 | $179 |
| Non-investment grade | 5 | 2 | 3 | — | — |
| No external ratings | | | | | |
| Internally rated—investment grade | 63 | 14 | 49 | — | — |
| Internally rated—non-investment grade | 1 | — | 1 | — | — |
| Total | $1,650 | $367 | $1,283 | 1 | $179 |

| Rating as of December 31, 2011 | Maturity of Credit Risk Exposure | | | |
|---|---|---|---|---|
| | Less than 2 Years | 2-5 Years | Exposure Greater than 5 Years | Total Exposure Before Credit Collateral |
| Investment grade | $1,127 | $359 | $ 95 | $1,581 |
| Non-investment grade | 5 | — | — | 5 |
| No external ratings | | | | |
| Internally rated—investment grade | 49 | 10 | 4 | 63 |
| Internally rated—non-investment grade | 1 | — | — | 1 |
| Total | $1,182 | $369 | $ 99 | $1,650 |

| Net Credit Exposure by Type of Counterparty | As of December 31, 2011 |
|---|---|
| Financial Institutions | $ 391 |
| Investor-owned utilities, marketers and power producers | 552 |
| Energy cooperatives and municipalities | 282 |
| Other | 58 |
| Total | $1,283 |

### ComEd

Credit risk for ComEd is managed by credit and collection policies, which are consistent with state regulatory requirements. ComEd is currently obligated to provide service to all electric customers within its franchised territory. ComEd records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. ComEd will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. In February 2010, the ICC approved ComEd's tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense. The Illinois Settlement Legislation prohibits utilities, including ComEd, from terminating electric service to a residential electric space heat customer due to nonpayment between December 1 of any year through March 1 of the following year. ComEd's ability to disconnect non space-heating residential customers is also impacted by certain weather restrictions, at any time of year, under the Illinois Public Utilities Act. ComEd will monitor the impact of its disconnection practices and will make any necessary adjustments to the provision for uncollectible accounts. ComEd did not have any customers representing over 10% of its revenues as of December 31, 2011. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information regarding ComEd's recently approved tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion. The unsecured credit used by the suppliers represents ComEd's credit exposure. As of December 31, 2011, ComEd's credit exposure to energy suppliers was immaterial.

***PECO***

Credit risk for PECO is managed by credit and collection policies, which are consistent with state regulatory requirements. PECO is currently obligated to provide service to all retail electric customers within its franchised territory. PECO records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1 of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with PAPUC regulations, after November 30 and before April 1, an electric distribution utility or natural gas distribution utility shall not terminate service to customers with household incomes at or below 250% of the Federal poverty level. PECO's provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in PAPUC regulations. PECO did not have any customers representing over 10% of its revenues as of December 31, 2011.

PECO's supplier master agreements that govern the terms of its DSP Program contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2011, PECO had no net credit exposure to suppliers.

PECO does not obtain cash collateral from suppliers under its natural gas supply and asset management agreements; however, the natural gas asset managers have provided $14 million in parental guarantees related to these agreements. As of December 31, 2011, PECO had credit exposure of $11 million under its natural gas supply and asset management agreements with investment grade suppliers.

**Collateral**

**Generation**

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

Generation sells output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities which serve as liquidity sources to fund collateral requirements. On March 23, 2011, Generation replaced their unsecured revolving credit facility with new a new facility with aggregate bank commitments of $5.3 billion. In addition, on

February 22, 2011, Generation satisfied all conditions precedent to the effectiveness and availability of credit under a bilateral credit facility for loans and letters of credit in the aggregate maximum amount of $300 million, which is the limit currently authorized by the board of directors of Exelon. See Note 10 – Debt and Credit Agreements for additional information.

As of December 31, 2011, Generation was holding $542 million of cash collateral deposits received from counterparties. Net cash collateral deposits received of $540 million were offset against mark-to-market assets and liabilities. As of December 31, 2011, $2 million of cash collateral received was not offset against net derivative positions because it was not associated with energy-related derivatives. As of December 31, 2010, Generation was holding $955 million of cash collateral deposits received from counterparties and Generation had sent $3 million of cash collateral to counterparties. Net cash collateral deposits received of $951 million were offset mark-to-market assets and liabilities. As of December 31, 2010, $1 million of cash collateral received was not offset against net mark-to-market assets and liabilities. See Note 18 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

**ComEd**

As of December 31, 2011, ComEd held an immaterial amount of cash and letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for both annual and long-term renewable energy contracts. See Notes 2 and 9 of the Combined Notes to Consolidated Financial Statements for further information.

**PECO**

As of December 31, 2011, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 9 of the Combined Notes to Consolidated Financial Statements for further information.

***RTOs and ISOs***

Generation, ComEd and PECO 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 Exelon's 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 act as the counterparty to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX and ICE are significantly collateralized and have limited counterparty credit risk.

***Long-Term Leases***

Exelon's Consolidated Balance Sheets, as of December 31, 2011, included a $656 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of approximately $1.5 billion, less unearned income of $836 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms which are set at prices above the then expected fair market value of the plants. If the lessees do not exercise the fixed purchase options the lessees return the leasehold interests to Exelon and Exelon has the ability to require the lessees to arrange a service contract with a third party for a period following the lease term. In any event, Exelon is subject to residual value risk to the extent the fair value of the assets are less than the residual value. This risk is mitigated by the fair value of the fixed payments under the service contract. The term of the service contract, however, is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures including letters of credit, surety bonds and credit swaps. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Since 2008, the entity providing the credit enhancement for one of the lessees did not meet the credit rating requirements of the lease. Consequently, Exelon has indefinitely extended a waiver and reduction of the rating requirement, which Exelon may terminate by giving 90 days notice to the lessee. Exelon monitors the continuing credit quality of the credit enhancement party.

Exelon performed annual assessments as of July 31, 2011 and 2010 of the estimated fair value of long-term lease investments and concluded that the estimated fair values at the end of the lease terms exceeded the residual values ($1.5 billion as noted above) established at the lease dates and recorded as investments on Exelon's balance sheet. Through December 31, 2011, no events have occurred or circumstances have changed that would require any formal reassessment subsequent to the July 2011 review.

**Interest-Rate Risk**

Exelon uses a combination of fixed-rate and variable-rate debt to manage interest-rate exposure. Exelon may also use interest rate swaps when deemed appropriate to adjust exposure based upon market conditions. Additionally, Exelon 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, 2011, Exelon had $100 million of notional amounts of fair value hedges outstanding and Generation had $485 million of notional amounts of cash flow hedges outstanding. A hypothetical 10% increase in the interest rates associated with variable-rate debt would result in less than a $1 million decrease in Exelon's, Generation's and ComEd's pre-tax earnings for the year ended December 31, 2011. This calculation holds all other variables constant and assumes only the discussed changes in interest rates.

**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, 2011, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets in Exelon's 2011 Form 10-K. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $342 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See Management's Discussion and Analysis of Financial Condition and Results of Operations, for further discussion of equity price risk as a result of the current capital and credit market conditions.

## CERTIFICATIONS

The CEO of Exelon has made the required annual certifications for 2011 to the New York Stock Exchange and the Philadelphia Stock Exchange is in compliance with the listing standards of those exchanges. The CEO and CFO have filed with the SEC all required certifications under section 302 of the Sarbanes—Oxley Act of 2002. These certifications are filed as Exhibits 31-1 and 31-2 to Exelon's 2011 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, 2011. 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, 2011, Exelon's internal control over financial reporting was effective.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2012

## Report of Independent Registered Public Accounting Firm

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

In our opinion, the consolidated financial statements listed in the accompanying index appearing under Item 15(a)(1)(i) present fairly, in all material respects, the financial position of Exelon Corporation and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the accompanying index appearing under item 15(a)(1)(ii) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, 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 and financial statement schedules, 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, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP
Chicago, Illinois
February 9, 2012

**Exelon Corporation and Subsidiary Companies**

**Consolidated Statements of Operations and Comprehensive Income**

| (In millions, except per share data) | For the Years Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| **Operating revenues** | $18,924 | $18,644 | $17,318 |
| **Operating expenses** | | | |
| Purchased power | 5,284 | 4,425 | 3,215 |
| Fuel | 1,844 | 2,010 | 2,066 |
| Operating and maintenance | 5,012 | 4,453 | 4,612 |
| Operating and maintenance for regulatory required programs | 184 | 147 | 63 |
| Depreciation and amortization | 1,335 | 2,075 | 1,834 |
| Taxes other than income | 785 | 808 | 778 |
| Total operating expenses | 14,444 | 13,918 | 12,568 |
| **Operating income** | 4,480 | 4,726 | 4,750 |
| **Other income and deductions** | | | |
| Interest expense, net | (701) | (792) | (654) |
| Interest expense to affiliates, net | (25) | (25) | (77) |
| Loss in equity method investments | (1) | — | (27) |
| Other, net | 199 | 312 | 427 |
| Total other income and deductions | (528) | (505) | (331) |
| **Income before income taxes** | 3,952 | 4,221 | 4,419 |
| **Income taxes** | 1,457 | 1,658 | 1,712 |
| **Net income** | 2,495 | 2,563 | 2,707 |
| **Other comprehensive income (loss)** | | | |
| Pension and non-pension postretirement benefit plans: | | | |
| Prior service benefit reclassified to periodic costs, net of taxes of $(4), $(7) and $(6), respectively | (5) | (11) | (13) |
| Actuarial loss reclassified to periodic cost, net of taxes of $93, $79 and $74, respectively | 136 | 114 | 93 |
| Transition obligation reclassified to periodic cost, net of taxes of $2, $2 and $2, respectively | 4 | 3 | 3 |
| Pension and non-pension postretirement benefit plan valuation adjustment, net of taxes of $(171), $(188) and $47, respectively | (250) | (288) | 86 |
| Change in unrealized gain (loss) on cash flow hedges, net of taxes of $39, $(107) and $(2), respectively | 88 | (151) | (12) |
| Change in unrealized gain (loss) on marketable securities, net of taxes of $0, $0 and $3, respectively | — | (1) | 5 |
| Other comprehensive income (loss) | (27) | (334) | 162 |
| **Comprehensive income** | $ 2,468 | $ 2,229 | $ 2,869 |
| **Average shares of common stock outstanding:** | | | |
| Basic | 663 | 661 | 659 |
| Diluted | 665 | 663 | 662 |
| **Earnings per average common share:** | | | |
| Basic | $ 3.76 | $ 3.88 | $ 4.10 |
| Diluted | $ 3.75 | $ 3.87 | $ 4.09 |
| **Dividends per common share** | $ 2.10 | $ 2.10 | $ 2.10 |

See the Combined Notes to Consolidated Financial Statements

## Exelon Corporation and Subsidiary Companies

## Consolidated Statements of Cash Flows

| (In millions) | For the Years Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| **Cash flows from operating activities** | | | |
| Net income | $ 2,495 | $ 2,563 | $ 2,707 |
| Adjustments to reconcile net income to net cash flows provided by operating activities: | | | |
| Depreciation, amortization and accretion, including nuclear fuel amortization | 2,304 | 2,943 | 2,601 |
| Impairment of long-lived assets | — | — | 223 |
| Deferred income taxes and amortization of investment tax credits | 1,457 | 981 | 756 |
| Net fair value changes related to derivatives | 291 | (88) | (95) |
| Net realized and unrealized losses (gains) on nuclear decommissioning trust fund investments | 14 | (105) | (207) |
| Other non-cash operating activities | 782 | 609 | 652 |
| Changes in assets and liabilities: | | | |
| Accounts receivable | 57 | (232) | 234 |
| Inventories | (58) | (62) | 51 |
| Accounts payable, accrued expenses and other current liabilities | (254) | 472 | (254) |
| Option premiums paid, net | (3) | (124) | (40) |
| Counterparty collateral (posted) received, net | (344) | (155) | 196 |
| Income taxes | 492 | (543) | (29) |
| Pension and non-pension postretirement benefit contributions | (2,360) | (959) | (588) |
| Other assets and liabilities | (20) | (56) | (113) |
| **Net cash flows provided by operating activities** | 4,853 | 5,244 | 6,094 |
| **Cash flows from investing activities** | | | |
| Capital expenditures | (4,042) | (3,326) | (3,273) |
| Proceeds from nuclear decommissioning trust fund sales | 6,139 | 3,764 | 4,292 |
| Investment in nuclear decommissioning trust funds | (6,332) | (3,907) | (4,531) |
| Acquisitions | (387) | (893) | — |
| Proceeds from sales of investments | 6 | 28 | 41 |
| Purchases of investments | (4) | (22) | (28) |
| Change in restricted cash | (3) | 423 | 35 |
| Other investing activities | 20 | 39 | 6 |
| **Net cash flows used in investing activities** | (4,603) | (3,894) | (3,458) |
| **Cash flows from financing activities** | | | |
| Changes in short-term debt | 161 | (155) | (56) |
| Issuance of long-term debt | 1,199 | 1,398 | 1,987 |
| Retirement of long-term debt | (789) | (828) | (1,773) |
| Retirement of long-term debt of variable interest entity | — | (806) | — |
| Retirement of long-term debt to financing affiliates | — | — | (709) |
| Dividends paid on common stock | (1,393) | (1,389) | (1,385) |
| Proceeds from employee stock plans | 38 | 48 | 42 |
| Other financing activities | (62) | (16) | (3) |
| **Net cash flows used in financing activities** | (846) | (1,748) | (1,897) |
| **Increase (decrease) in cash and cash equivalents** | (596) | (398) | 739 |
| **Cash and cash equivalents at beginning of period** | 1,612 | 2,010 | 1,271 |
| **Cash and cash equivalents at end of period** | $ 1,016 | $ 1,612 | $ 2,010 |

See the Combined Notes to Consolidated Financial Statements

**Exelon Corporation and Subsidiary Companies**

**Consolidated Balance Sheets**

| (In millions) | December 31, 2011 | December 31, 2010 |
|---|---|---|
| **ASSETS** | | |
| **Current assets** | | |
| Cash and cash equivalents | $ 1,016 | $ 1,612 |
| Restricted cash and investments | 40 | 30 |
| Accounts receivable, net | | |
| Customer ($329 and $346 gross accounts receivables pledged as collateral as of December 31, 2011 and 2010, respectively) | 1,613 | 1,932 |
| Other | 1,000 | 1,196 |
| Mark-to-market derivative assets | 432 | 487 |
| Inventories, net | | |
| Fossil fuel | 208 | 216 |
| Materials and supplies | 656 | 590 |
| Deferred income taxes | 97 | — |
| Regulatory assets | 69 | 10 |
| Other | 358 | 325 |
| Total current assets | 5,489 | 6,398 |
| **Property, plant and equipment, net** | 32,570 | 29,941 |
| **Deferred debits and other assets** | | |
| Regulatory assets | 4,839 | 4,140 |
| Nuclear decommissioning trust funds | 6,507 | 6,408 |
| Investments | 751 | 717 |
| Investments in affiliates | 15 | 15 |
| Goodwill | 2,625 | 2,625 |
| Mark-to-market derivative assets | 650 | 409 |
| Pledged assets for Zion Station decommissioning | 734 | 824 |
| Other | 912 | 763 |
| Total deferred debits and other assets | 17,033 | 15,901 |
| **Total assets** | $55,092 | $52,240 |

See the Combined Notes to Consolidated Financial Statements

## Exelon Corporation and Subsidiary Companies

## Consolidated Balance Sheets

| (In millions) | December 31, 2011 | December 31, 2010 |
|---|---|---|
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current liabilities** | | |
| Short-term borrowings | $ 163 | $ — |
| Short-term notes payable—accounts receivable agreement | 225 | 225 |
| Long-term debt due within one year | 828 | 599 |
| Accounts payable | 1,444 | 1,373 |
| Mark-to-market derivative liabilities | 112 | 38 |
| Accrued expenses | 1,255 | 1,040 |
| Deferred income taxes | — | 85 |
| Regulatory liabilities | 53 | 44 |
| Dividends payable | 349 | 1 |
| Other | 560 | 835 |
| Total current liabilities | 4,989 | 4,240 |
| **Long-term debt** | 11,799 | 11,614 |
| **Long-term debt to other financing trusts** | 390 | 390 |
| **Deferred credits and other liabilities** | | |
| Deferred income taxes and unamortized investment tax credits | 8,351 | 6,621 |
| Asset retirement obligations | 3,884 | 3,494 |
| Pension obligations | 2,194 | 3,658 |
| Non-pension postretirement benefit obligations | 2,263 | 2,218 |
| Spent nuclear fuel obligation | 1,019 | 1,018 |
| Regulatory liabilities | 3,771 | 3,555 |
| Mark-to-market derivative liabilities | 126 | 21 |
| Payable for Zion Station decommissioning | 563 | 659 |
| Other | 1,268 | 1,102 |
| Total deferred credits and other liabilities | 23,439 | 22,346 |
| Total liabilities | 40,617 | 38,590 |
| **Commitments and contingencies** | | |
| **Preferred securities of subsidiary** | 87 | 87 |
| **Shareholders' equity** | | |
| Common stock (No par value, 2,000 shares authorized, 663 and 662 shares outstanding at December 31, 2011 and 2010, respectively) | 9,107 | 9,006 |
| Treasury stock, at cost (35 shares held at December 31, 2011 and 2010, respectively) | (2,327) | (2,327) |
| Retained earnings | 10,055 | 9,304 |
| Accumulated other comprehensive loss, net | (2,450) | (2,423) |
| Total shareholders' equity | 14,385 | 13,560 |
| Noncontrolling interest | 3 | 3 |
| Total equity | 14,388 | 13,563 |
| **Total liabilities and shareholders' equity** | $55,092 | $52,240 |

See the Combined Notes to Consolidated Financial Statements

## Exelon Corporation and Subsidiary Companies

## Consolidated Statements of Changes in Shareholders' Equity

| (In millions, shares in thousands) | Issued Shares | Common Stock | Treasury Stock | Retained Earnings | Accumulated Other Comprehensive Loss | Noncontrolling Interest | Total Shareholders' Equity |
|---|---|---|---|---|---|---|---|
| **Balance, December 31, 2008** | 692,953 | $8,816 | $(2,338) | $ 6,820 | $(2,251) | $— | $11,047 |
| Net income | — | — | — | 2,707 | — | — | 2,707 |
| Long-term incentive plan activity | 1,088 | 85 | 10 | (5) | — | — | 90 |
| Employee stock purchase plan issuances | 524 | 22 | — | — | — | — | 22 |
| Common stock dividends | — | — | — | (1,388) | — | — | (1,388) |
| Other comprehensive income, net of income taxes of $119 | — | — | — | — | 162 | — | 162 |
| **Balance, December 31, 2009** | 694,565 | $8,923 | $(2,328) | $ 8,134 | $(2,089) | $— | $12,640 |
| Net income | — | — | — | 2,563 | — | — | 2,563 |
| Long-term incentive plan activity | 1,380 | 60 | 1 | (1) | — | — | 60 |
| Employee stock purchase plan issuances | 644 | 23 | — | — | — | — | 23 |
| Common stock dividends | — | — | — | (1,392) | — | — | (1,392) |
| Acquisition of Exelon Wind | — | — | — | — | — | 3 | 3 |
| Other comprehensive loss, net of income taxes of $(221) | — | — | — | — | (334) | — | (334) |
| **Balance, December 31, 2010** | 696,589 | $9,006 | $(2,327) | $ 9,304 | $(2,423) | $ 3 | $13,563 |
| Net income | — | — | — | 2,495 | — | — | 2,495 |
| Long-term incentive plan activity | 861 | 76 | — | — | — | — | 76 |
| Employee stock purchase plan issuances | 662 | 25 | — | — | — | — | 25 |
| Common stock dividends | — | — | — | (1,744) | — | — | (1,744) |
| Other comprehensive loss, net of income taxes of $(41) | — | — | — | — | (27) | — | (27) |
| **Balance, December 31, 2011** | 698,112 | $9,107 | $(2,327) | $10,055 | $(2,450) | $ 3 | $14,388 |

See the Combined Notes to Consolidated Financial Statements

## Combined Notes to Consolidated Financial Statements

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

### 1. Significant Accounting Policies

### Description of Business

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

### Basis of Presentation

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

Exelon owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for ComEd, of which Exelon owns more than 99%, and PECO, of which Exelon owns 100% of the common stock but none of PECO's preferred securities. Exelon has reflected the third-party interests in ComEd, which totaled less than $1 million at December 31, 2011 and December 31, 2010, as equity and PECO's preferred securities as preferred securities of subsidiary in its consolidated financial statements.

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

ComEd owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for RITELine Illinois, LLC of which ComEd owns 75% and 12.5% is indirectly owned by Exelon, which is eliminated in Exelon's consolidated financial statements. Exelon and ComEd have reflected the third-party interests of 12.5% and 25%, respectively, in RITELine Illinois, LLC, which both totaled less than $1 million at December 31, 2011, as equity.

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

Each of Generation's, ComEd's and PECO's consolidated financial statements in the 2011 Form 10-K includes the accounts of their subsidiaries. All intercompany transactions have been eliminated.

### Use of Estimates

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

### Reclassifications

Certain prior year amounts in Exelon's Consolidated Balance Sheets have been reclassified between line items for comparative purposes. The reclassifications did not affect net income or cash flows from operating activities of Exelon.

### Accounting for the Effects of Regulation

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

### Variable Interest Entities

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

#### *Generation*

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

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

Generation has historically aggregated its contracts with VIEs into two categories, energy commitments and fuel purchase obligations, based on similar risk characteristics and significance to Generation. As of the balance sheet date, the carrying amount of assets and liabilities in Generation's Consolidated Balance Sheets in Exelon's 2011 Form 10-K that relate to its involvement with these VIEs are predominately related to working capital accounts and generally represent the amounts owed by Generation for the deliveries associated with the current billing cycles under the contracts. Further, Generation has not provided or guaranteed any debt or equity support, or any liquidity arrangements, performance guarantees or other commitments associated with these contracts, so there is no significant potential exposure to loss as a result of its involvement with the VIEs.

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

On December 9, 2010, Generation completed the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind), discussed further in Note 3—Acquisition. Generation evaluated the significant agreements and ownership structures and risks of each of the wind projects and underlying entities acquired, and determined that the entities are VIEs for which Generation is the primary beneficiary and consolidation is required. Each project was designed to develop, construct and operate a wind generation facility. Generation owns 100% of most projects acquired; however, 12 of the projects have noncontrolling equity interests held by others (which range between 1% and 6%). Of the 12 projects, Generation's economic interests in nine of the projects are significantly greater than its stated contractual governance rights. However, Generation has determined that its significant economic interests in the projects include the power to direct the activities most significant to the projects. The primary factors considered in determining that Generation is the primary beneficiary were that Generation has the power to direct the operations and maintenance of the wind facilities, which is considered the activity that most significantly affects the economic performance of the projects, and the obligation to absorb losses and right to receive benefits that are significant to the projects. The ownership agreements with the noncontrolling interests state that Generation is to provide financial support to the projects in proportion to its economic interests in the projects (which range between 99% and 94%). No additional support to these projects beyond what was contractually required has been provided during 2011. As of December 31, 2011, the carrying amount of the assets and liabilities that are consolidated as a result of Generation being the primary beneficiary of these entities primarily relate to the wind generating assets, PPA intangible assets and working capital amounts.

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

***ComEd and PECO***

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

For contracts where ComEd or PECO has a variable interest, consideration has been given to which interest holder has the power to direct the activities that most significantly affect the economic performance of the VIE. In general, the most significant activity of the VIEs is the operation and maintenance of their production or procurement processes related to electricity, RECs, AECs or natural gas. ComEd and PECO do not have control over the operation and maintenance of the entities considered VIEs and they do not bear operational risk related to the associated activities. Furthermore, ComEd and PECO have no debt or equity investments in the VIEs and do not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 18—Commitments and Contingencies. Accordingly, neither ComEd nor PECO considers itself to be the primary beneficiary of these VIEs.

As of the balance sheet date, the carrying amounts of assets and liabilities in ComEd's and PECO's Consolidated Balance Sheets in Exelon's 2011 Form 10-K that relate to their involvement with these VIEs were predominately related to working capital accounts and generally represented the amounts owed by ComEd and PECO for the purchases associated with the current billing cycles under the contracts.

The financing trust of ComEd, ComEd Financing III, and the financing trusts of PECO, PECO Trust III and PECO Trust IV, are not consolidated in Exelon's, ComEd's or PECO's financial statements. These financing trusts were created to issue mandatorily redeemable trust preferred securities. ComEd and PECO have concluded that they do not have a variable interest in ComEd Financing III, PECO Trust III or PECO Trust IV as each Registrant financed its equity interest in the financing trusts through the issuance of subordinated debt and, therefore, has no equity at risk. ComEd and PECO, as the sponsors of the financing trusts, are obligated to pay the operating expenses of the trusts.

***PECO***

PETT, a financing trust, was created in 1998 by PECO to purchase and own intangible transition property (ITP) and to issue transition bonds to securitize $5 billion of PECO's stranded cost recovery authorized by the PAPUC pursuant to the Competition Act. PECO made an initial capital contribution of $25 million to PETT. ITP represented the irrevocable right of PECO to collect intangible transition charges (ITC). ITC consisted of the portion of CTCs that were sold by PECO to PETT and securitized through the various issuances of PETT's transition bonds from 1999 through 2001 as authorized by the PAPUC. ITC provided PETT with an asset sufficient to recover the aggregate principal amount of the transition bonds issued, plus amounts sufficient to provide for the credit enhancement, interest payments, servicing fees and other expenses relating to the transition bonds. PETT's assets were restricted for the sole purpose of satisfying PETT's obligation to its transition bondholders and payment of various administrative fees. PECO did not provide ongoing financial support to PETT or guarantee PETT's performance, and the transition bondholders did not have recourse to PECO. PECO had continuing involvement in PETT in its role as the servicer of the ITC collections, for which PECO received a fee.

PETT was consolidated in Exelon's and PECO's financial statements on January 1, 2010 pursuant to authoritative guidance relating to the consolidation of VIEs that became effective on that date. Under previously issued authoritative guidance, PETT was deconsolidated in accordance with a prescribed quantitative approach, based on expected losses, for determining the primary beneficiary. Under the new guidance, PECO concluded that it was the primary beneficiary of PETT due to PECO's involvement in the design of PETT, its role as servicer, and its right to dissolve PETT and receive any of its remaining assets following retirement of the transition bonds and payment of PETT's other expenses. The consolidation of PETT did not have a significant impact on PECO's results of operations or statement of cash flows. Upon retirement of the outstanding transition bonds on September 1, 2010, the remaining cash balance was remitted to PECO, and PETT was dissolved on September 20, 2010.

**Revenues**

***Operating Revenues***. Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, Exelon accrues an estimate for the unbilled amount of energy delivered or services provided to customers. ComEd records its best estimates of the distribution and transmission revenue impacts resulting from changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. See Notes 2—Regulatory Matters and 4—Accounts Receivable for further information.

***RTOs and ISOs.*** In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, Exelon generally reports sales and purchases conducted on a net hourly basis in either revenues or purchased power on their Consolidated Statements of Operations, the classification of which depends on the net hourly activity.

***Option Contracts, Swaps and Commodity Derivatives.*** Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense, unless hedge accounting is applied. Premiums received and paid on option contracts are recognized as revenue or expense over the terms of the contracts. If the derivatives meet hedging criteria, changes in fair value are recorded in OCI. ComEd has not elected hedge accounting for its financial swap contract with Generation. Since ComEd is entitled to full recovery of the costs of the financial swap contract in rates as settlements occur, ComEd records the fair value of the swap as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets in Exelon's 2011 Form 10-K.

***Trading Activities.*** Exelon and Generation account for Generation's trading activities under the provisions of the authoritative guidance for accounting for contracts involved in energy trading and risk management activities, which require energy revenues and costs related to energy trading contracts to be presented on a net basis in the income statement. Commodity derivatives used for trading purposes are accounted for using the mark-to-market method with unrealized gains and losses recognized in operating revenues.

**Income Taxes**

Deferred Federal and state income taxes are provided on all significant temporary differences between the book basis and the tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits previously utilized for income tax purposes have been deferred on Exelon's Consolidated Balance Sheets and are recognized in book income over the life of the related property. In accordance with applicable authoritative guidance, Exelon accounts for uncertain income tax positions using a benefit recognition model with a two-step approach; a more-likely-than-not recognition criterion and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more likely than not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. Exelon recognizes accrued interest related to unrecognized tax benefits in interest expense or in other income and deductions (interest income) on their Consolidated Statements of Operations.

Pursuant to the IRC and relevant state taxing authorities, Exelon and its subsidiaries file consolidated or combined income tax returns for Federal and certain state jurisdictions where allowed or required. See Note 11—Income Taxes for further information.

### Taxes Directly Imposed on Revenue-Producing Transactions

Exelon, Generation, ComEd and PECO present any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer on a gross (included in revenues and costs) basis. See Note 19—Supplemental Financial Information for Generation's, ComEd's and PECO's utility taxes that are presented on a gross basis.

### Cash and Cash Equivalents

Exelon considers investments purchased with an original maturity of three months or less to be cash equivalents.

### Restricted Cash and Investments

Restricted cash and investments represent restricted funds to satisfy designated current liabilities. As of December 31, 2011 and 2010, 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, 2011 and 2010, Generation's restricted cash and investments represented funds in escrow related to the acquisition of Shooting Star Wind Project, LLC, and for payment of certain environmental liabilities. As of December 31, 2010, Generation's restricted cash and investments represented funds for payment of certain environmental liabilities. As of December 31, 2011, ComEd's restricted cash primarily represented cash collateral held from suppliers associated with ComEd's energy and REC procurement contracts. As of December 31, 2011, PECO's restricted cash primarily represented funds from the sales of assets that were subject to PECO's mortgage indenture.

Restricted cash and investments not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2011 and 2010, Exelon and Generation's NDT funds, which are designated to satisfy future decommissioning obligations, were classified as noncurrent assets. As of December 31, 2011 and 2010, ComEd had short-term investments in Rabbi trusts classified as noncurrent assets.

### Allowance for Uncollectible Accounts

The allowance for uncollectible accounts reflects Exelon's best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable agings, historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balance by risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. ComEd and PECO customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd and PECO customer accounts are written off consistent with approved regulatory requirements. ComEd's and PECO's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC and PAPUC regulations, respectively. See Note 2—Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd.

### Inventories

Inventory is recorded at the lower of cost or market. Provisions are recorded for excess and obsolete inventory.

***Fossil Fuel.*** Fossil fuel inventory includes the weighted average costs of stored natural gas, propane, coal and oil. The costs of natural gas, propane, coal and oil are generally included in inventory when purchased and charged to fuel expense when used or sold.

***Materials and Supplies.*** Materials and supplies inventory generally includes the weighted average costs of transmission, distribution and generating plant materials. Materials are generally charged to inventory when purchased and expensed or capitalized to property, plant and equipment, as appropriate, when installed or used.

***Emission Allowances.*** Emission allowances are included in inventory and other deferred debits and are carried at the lower of weighted average cost or market and charged to fuel expense as they are used in operations.

**Marketable Securities**

All marketable securities are reported at fair value. Marketable securities held in the NDT funds are classified as trading securities and all securities that are not held by the NDT funds are classified as available-for-sale securities. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the former ComEd and former PECO nuclear generating units (Regulatory Agreement Units) are included in regulatory liabilities at Exelon, ComEd and PECO and in noncurrent payables to affiliates at Generation and in noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the former AmerGen nuclear generating units and the portions of the Peach Bottom nuclear generating units not subject to a regulatory agreement (Non-Regulatory Agreement Units) are included in earnings at Exelon and Generation. Unrealized gains and losses, net of tax, for ComEd's and PECO's available-for-sale securities are reported in OCI. Any decline in the fair value of ComEd's and PECO's available-for-sale securities below the cost basis is reviewed to determine if such decline is other-than-temporary. If the decline is determined to be other-than-temporary, the cost basis of the available-for-sale securities is written down to fair value as a new cost basis and the amount of the write-down is included in earnings. See Note 12—Asset Retirement Obligations for information regarding marketable securities held by NDT funds and Note 19—Supplemental Financial Information for additional information regarding ComEd's and PECO's regulatory assets and liabilities.

**Property, Plant and Equipment**

Property, plant and equipment is recorded at original cost. Original cost includes labor, materials and construction overhead. When appropriate, original cost also includes capitalized interest for Generation and Exelon Corporate and AFUDC for regulated property at ComEd and PECO. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to maintenance expense as incurred.

Third parties reimburse ComEd and PECO for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are netted against the project costs. DOE SGIG funds reimbursed to PECO by the DOE are accounted for as CIAC.

For Generation, upon retirement, the cost of property is charged to accumulated depreciation in accordance with the composite method of depreciation. Upon replacement of an asset, the costs to remove the asset, net of salvage, are capitalized when incurred to gross plant as part of the cost of the newly-installed asset and recorded to depreciation expense over the life of the new asset. Removal costs, net of salvage, incurred for property that will not be replaced is charged to expense as incurred.

For ComEd and PECO, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation in accordance with the composite method of depreciation. ComEd's depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with ComEd's regulatory recovery method. ComEd's actual incurred removal costs are applied against the related regulatory liability. PECO's removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method.

See Note 5—Property, Plant and Equipment, Note 6—Jointly Owned Electric Utility Plant and Note 19—Supplemental Financial Information for additional information regarding property, plant and equipment.

**Nuclear Fuel**

The cost of nuclear fuel is capitalized and charged to fuel expense using the unit-of-production method. The estimated disposal cost of SNF is established per the Standard Waste Contract with the DOE and is expensed through fuel expense at one mill ($0.001) per kWh of net nuclear generation. On-site SNF storage costs are capitalized or expensed as incurred based upon the nature of the costs. A portion of the storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed.

### Nuclear Outage Costs

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to operating and maintenance expense or capitalized to property, plant and equipment (based on the nature of the activities) 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 facilities. Such costs are capitalized when management considers project completion to be probable, primarily based on management's determination that the project is economically and operationally feasible, management and/or the Board of Directors has approved the project and has committed to a plan to develop it, and Exelon and Generation have received the required regulatory approvals or management believes the receipt of required regulatory approvals is probable. Upon commencement of construction, these costs will be charged to construction work in progress. Capitalized development costs are charged to operating and maintenance expense when project completion is no longer probable. At December 31, 2011 and 2010, Exelon and Generation's capitalized development costs totaled approximately $376 million and $20 million, respectively, which are included in Property, Plant and Equipment on Exelon's Consolidated Balance Sheets. These costs primarily include land rights and other third-party costs directly associated with the development of certain Exelon Wind projects. Approximately $2 million, $6 million and $23 million of costs were expensed by Exelon and Generation for the years ended December 31, 2011, 2010 and 2009, respectively. The 2011 and 2010 costs primarily related to the possible development of new renewable energy projects while the 2009 costs primarily related to the possible construction of a new nuclear plant in Texas.

### Capitalized Software Costs

Costs incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life or pursuant to prescribed regulatory requirements. The following table presents net unamortized capitalized software costs and amortization of capitalized software costs by year:

| Net unamortized software costs | |
|---|---|
| December 31, 2011 | $280 |
| December 31, 2010 | 312 |

| Amortization of capitalized software costs | |
|---|---|
| 2011 | $122 |
| 2010 | 104 |
| 2009 | 105 |

### Depreciation and Amortization

Except for the amortization of nuclear fuel, depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the composite method. ComEd's depreciation includes a provision for estimated removal costs as authorized by the ICC. The estimated service lives for ComEd and PECO are primarily based on the average service lives from the most recent depreciation study for each respective company. The estimated service lives of the nuclear-fuel generating facilities are based on the remaining useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses (to the extent that such renewal has not yet been granted) for all of Generation's operating nuclear generating stations except for Oyster Creek. See Note 18—Commitments and Contingencies for information regarding Oyster Creek. The estimated service lives of the hydroelectric generating facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the operating licenses. The estimated service lives of the fossil fuel and other renewable generating facilities are based on the remaining useful lives of the stations, which Generation periodically evaluates based on feasibility assessments taking into account economic and capital requirement considerations. See Note 5—Property, Plant and Equipment for further information regarding depreciation.

Amortization of regulatory assets is recorded over the recovery period specified in the related legislation or regulatory agreement. See Note 2—Regulatory Matters and 19—Supplemental Financial Information for additional information regarding Generation's nuclear fuel, Generation's ARC and the amortization of ComEd's and PECO's regulatory assets.

### Asset Retirement Obligations

The authoritative guidance for accounting for AROs requires the recognition of a liability for a legal obligation to perform an asset retirement activity even though the timing and/or method of settlement may be conditional on a future event. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years. Generation generally updates its ARO annually based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios. The liabilities associated with Exelon's non-nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years. Changes result from the passage of new laws and regulations and revisions to either the timing or amount of estimates of undiscounted cash flows and estimates of cost escalation factors. AROs are accreted each year to reflect the time value of money for these present value obligations through a charge to operating and maintenance expense in the Consolidated Statements of Operations or, in the case of the majority of ComEd's and PECO's accretion, through an increase to regulatory assets. See Note 12—Asset Retirement Obligations for additional information.

### Capitalized Interest and AFUDC

During construction, Exelon and Generation capitalize the costs of debt funds used to finance non-regulated construction projects. Capitalization of debt funds is recorded as a charge to construction work in progress and as a non-cash credit to interest expense.

Exelon, ComEd and PECO apply the authoritative guidance for accounting for certain types of regulation to calculate AFUDC, which is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded as a charge to construction work in progress and as a non-cash credit to AFUDC that is included in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

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

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Total incurred interest (a) | 783 | 861 | 786 |
| Capitalized interest | 49 | 38 | 50 |
| Credits to AFUDC debt and equity | 25 | 16 | 14 |

(a) Includes interest expense to affiliates.

### Guarantees

Exelon recognizes, 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 Exelon is released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of Exelon may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 18—Commitments and Contingencies for additional information.

### Asset Impairments

***Long-Lived Assets.*** Exelon evaluates the carrying value of their long-lived assets, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. See Note 5—Property, Plant and Equipment for a discussion of asset impairment evaluations made by Generation.

***Goodwill.*** Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is tested for impairment at least annually or on an interim basis if an event occurs or circumstances change that could reduce the fair value of a reporting unit below its carrying value. See Note 7—Intangible Assets for additional information regarding Exelon's and ComEd's goodwill.

**Derivative Financial Instruments**

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For other derivative contracts that do not qualify or are not designated for hedge accounting, changes in the fair value of the derivatives are recognized in earnings each period. For energy-related derivatives entered into for proprietary trading purposes, which are subject to Exelon's Risk Management Policy, changes in the fair value of the derivatives are recognized in earnings each period. Amounts classified in earnings are included in revenue, purchased power and fuel, or other, net on the Consolidated Statements of Operations. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the underlying nature of Exelon's hedged items.

Revenues and expenses on contracts that qualify, and are designated, as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and price is not tied to an unrelated underlying derivative. As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the exceptions, the fair value of the related contract would be recorded on the balance sheet and immediately recognized through earnings at Generation or offset by a regulatory asset or liability at ComEd and PECO. See Note 9—Derivative Financial Instruments for additional information.

**Retirement Benefits**

Generation, ComEd and PECO participate in Exelon's defined benefit pension plans and other postretirement plans. AmerGen sponsored a separate defined benefit pension plan and postretirement plan for its employees until the merger of AmerGen into Generation on January 8, 2009. Exelon became the sponsor of those plans at that date.

The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, including numerous assumptions and accounting elections. The assumptions are reviewed annually and at any interim remeasurement of the plan obligations. The impact of assumption changes on pension and other postretirement benefit obligations is generally recognized over the expected average remaining service period of the employees rather than immediately recognized in the income statement. See Note 13—Retirement Benefits for additional discussion of Exelon's accounting for retirement benefits.

**New Accounting Pronouncements**

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

***Fair Value Measurements***

In May 2011, the FASB issued authoritative guidance amending existing guidance for measuring fair value and for disclosing information about fair value measurements. The FASB indicated that for many of the requirements it does not intend for the amendments to result in a change to current accounting. Required disclosures are expanded under the new guidance, especially for fair value measurements that are categorized within Level 3 of the fair value hierarchy, for which quantitative information about the unobservable inputs, the valuation processes used by the entity, and the sensitivity of the measurement to the unobservable inputs will be required. In addition, entities will be required to disclose the categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed. The guidance is effective for Exelon for periods beginning after December 15, 2011 and is required to be applied prospectively. Exelon is not currently impacted by the changes regarding the measurement of fair value and will include the required disclosures in their March 31, 2012 Form 10-Q.

***Statement of Comprehensive Income***

In June 2011, the FASB issued authoritative guidance requiring entities to present net income and other comprehensive income in a single continuous statement of comprehensive income or in two separate, but consecutive, statements. The new guidance does not change the components that are recognized in net income and the components that are recognized in other comprehensive income. The guidance originally required entities to present reclassifications between net income and other comprehensive income at the financial statement line item level; however, in December 2011, the FASB deferred this requirement. This guidance is effective for Exelon for periods beginning after December 15, 2011 and is required to be applied retroactively. Exelon currently presents a single statement of comprehensive income, consistent with the new guidance.

***Goodwill Impairment Assessments***

In September 2011, the FASB issued authoritative guidance amending existing guidance on the annual assessment of goodwill for impairment. Under the revised guidance, entities assessing goodwill for impairment have the option of performing a qualitative assessment before calculating the fair value of the reporting unit (i.e., step one of the two-step fair value based impairment test). If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not less than the carrying amount, the two-step fair value based impairment test is required. Otherwise, no further testing is required. This guidance is effective for Exelon for periods beginning after December 15, 2011 and is not expected to have an impact on their consolidated financial statements.

***Disclosures About Offsetting Assets and Liabilities***

In December 2011, the FASB issued authoritative guidance requiring entities to expand disclosures about instruments and transactions eligible for offset in the Balance Sheet, and instruments and transactions subject to an agreement similar to a master netting arrangement. The required disclosures will include both gross and net information about instruments to which the guidance applies, including derivatives and securities borrowing and securities lending arrangements. This guidance is effective for the Registrants for periods beginning on or after January 1, 2013 and is required to be applied retroactively. As this guidance provides only disclosure requirements, the adoption of this standard will not impact Exelon's results of operations, cash flows or financial positions.

## 2. Regulatory Matters

The following matters below discuss, in all material respects, the current status of Exelon's regulatory and legislative proceedings.

### Illinois Regulatory Matters

***Legislation to Modernize Electric Utility Infrastructure and to Update Illinois Ratemaking Process.*** On October 26, 2011, the Illinois General Assembly overrode the Governor's veto of the Illinois Energy Infrastructure Modernization Act (SB 1652), which became effective immediately. The Illinois General Assembly also passed House Bill 3036 (the Trailer Bill), which modifies and supplements SB 1652. The Governor signed the Trailer Bill into law on December 30, 2011. The combined legislation (EIMA) provides for substantial capital investment over a ten-year period to modernize Illinois' electric utility infrastructure and for greater certainty related to the recovery of costs by a utility through a pre-established formula rate tariff. On January 6, 2012, ComEd filed its Infrastructure Investment Plan with the ICC. Under the plan, ComEd will invest approximately $2.6 billion over the next ten years to modernize and storm-harden its distribution system and to implement smart grid technology. These investments will be incremental to ComEd's historical level of capital expenditures. Approximately $1.3 billion will be invested in smart grid/smart meter technology that will place a smart meter with all customers and provide extensive customer education over the next nine years. The smart meter/smart grid technology is designed to significantly improve meter reading and to reduce the frequency and duration of outages. Approximately $1.3 billion will be invested to improve ComEd's infrastructure, including $200 million for storm hardening the distribution system. The January 6, 2012 filing with the ICC also included ComEd's $233 million investment plan for 2012. Implementation of the investment plan began in early 2012 and smart meter installation in homes and businesses is expected to begin later in 2012, subject to approval of ComEd's AMI Deployment Plan by the ICC. Additionally, ComEd will contribute $10 million per year for five years, as long as EIMA remains in effect, to fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates. ComEd will also make an initial contribution of $15 million to a new Science and Technology Innovation Trust fund that will be used to fund energy innovation. Subsequently, ComEd will make annual contributions to the fund of approximately $4 million for as long as the AMI Deployment Plan remains in effect.

EIMA provides for a performance-based distribution formula rate tariff. On November 8, 2011, ComEd filed its initial formula rate tariff and associated testimony based on 2010 costs and 2011 plant additions. The primary purpose of this initial proceeding is to establish the formula under which rates will be calculated going-forward. The initial rate, which is expected to be lower than current rates but will be subject to reconciliation, will take effect within 30 days after the ICC order, which must be issued by May 31, 2012.

The legislation provides for an annual reconciliation of the revenue requirement in effect to reflect the actual costs that the ICC determines are prudently and reasonably incurred in a given year. The first year for which the reconciliation will be performed is 2011. ComEd will make its initial reconciliation filing in May 2012, and the rate adjustments necessary to reconcile 2011 revenues to ComEd's actual 2011 costs incurred will take effect in January 2013 after the ICC's review. As of December 31, 2011, ComEd recorded an estimated regulatory asset of $84 million and an offsetting increase in revenues for the 2011 reconciliation and net decrease in operating and maintenance expense for the deferral of certain storm costs of $29 million and $55 million, respectively. This regulatory asset represents ComEd's best estimate of the probable increase in distribution rates expected to be approved by the ICC to provide ComEd recovery of all prudently and reasonably incurred costs in 2011 and an earned rate of return on common equity, as defined in the legislation, for 2011. As the ICC proceeding to review ComEd's initially filed formula rate tariff progresses through May 2012, ComEd will adjust the estimated regulatory asset recorded as of December 31, 2011, to reflect any revisions made to the proposed formula by the ICC. ComEd currently does not anticipate any such adjustments would be material to its overall results of operations, financial position or cash flows. The positive impact of the reconciliation mechanism on ComEd's 2011 pre-tax income was partially offset by the recognition of the $15 million contribution to be made to the Science and Technology Innovation Trust fund discussed above.

Under the terms of EIMA, for the 2011 annual reconciliation period, ComEd's earned rate of return on common equity is required to be within plus or minus 50 basis points ("the collar") of the target rate determined as the annual average rate on 30-year treasury notes plus 590 basis points. Subsequent to the 2011 annual reconciliation period, the earned rate of return on common equity is required to be within the collar of the target rate determined as the annual average rate on 30-year treasury notes plus 580 basis points. In addition, the target rate of return on common equity is subject to reduction by up to 30 basis points each year beginning in 2013, gradually increasing to 38 basis points for each of the last four years, if ComEd does not deliver the reliability and customer service benefits, as defined, it has committed to over the ten-year life of the investment program. The reliability metrics relate to improvements in outage frequency and duration and the customer service metrics relate to reductions in estimated bills, unaccounted for energy and uncollectible expense. EIMA also specifies the rate treatment for pension, incentive compensation and severance costs. In order to protect consumers, the legislation will terminate, ending ComEd's investment commitment, contribution commitments and the performance-based formula rates, (a) if the average residential rate increases by more than 2.5% annually from June 2011 through May 2014 or (b) at December 31, 2017 unless approved to continue by the Illinois General Assembly. There are additional restrictions and potential criteria for the program to end earlier than December 31, 2017.

***Appeal of 2007 Illinois Electric Distribution Rate Case.*** The ICC issued an order in ComEd's 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd's annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a 10.3% rate of return on common equity. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). The Court issued a decision on September 30, 2010, ruling against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via a rider (Rider SMP). On January 25, 2011, ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court which was denied on March 30, 2011. The ICC has initiated a proceeding on remand. ComEd expects that the ICC will issue a final order in that proceeding in early 2012.

The Court held the ICC abused its discretion in not reducing ComEd's rate base to account for an additional 18 months of accumulated depreciation while including post-test year pro forma plant additions through that period (the same position ComEd took in its 2010 electric distribution rate case (2010 Rate Case) discussed below). The Court's ruling may trigger a refund obligation. An interest charge may accrue on any refund amount. The impact on ComEd's rates and any associated refund obligation should be prospective from no earlier than the date of the Court's ruling on September 30, 2010. ComEd continued to bill rates as established under the ICC's order in the 2007 Rate Case until June 1, 2011 when the rates set in the 2010 Rate Case became effective. In August 2011, ComEd filed testimony in the remand proceeding that no refunds should be required. If the ICC decides that refunds are required, ComEd's testimony stated that the maximum potential refund should be approximately $30 million. On November 10, 2011, the ALJ issued a proposed order in the remand proceeding agreeing with ComEd that the ICC does not have the legal authority to order a refund; a refund may only be ordered by a court. The ALJ also concluded that, to the extent that a court orders a refund, it should be in the amount of $37 million, including interest.

The Court also reversed the ICC's approval of ComEd's Rider SMP, a program which included the installation of 131,000 smart meters in the Chicago area. In 2009, the ICC approved a modified version of Rider SMP (Rider AMP). The Court held that the ICC's approval of Rider SMP constituted illegal single-issue ratemaking. The Court's decision prescribes a new, more stringent, standard for cost recovery riders not specifically authorized by statute. Such riders would be allowed only if: (1) the pass-through cost is imposed by an "external circumstance" and is unexpected, volatile, or fluctuating; and (2) recovery via rider does not change other expenses or increase utility income. Rider AMP is the subject of a separate appeal that is still pending. ComEd does not believe any of its other riders are affected by the Court's ruling.

Subsequent to the Court's ruling, ComEd filed a request with the ICC to allow it to request recovery, through inclusion in the 2010 Rate Case, of operating and maintenance costs that would have been recovered through Rider AMP, as well as continued rider recovery of carrying costs associated with capital investment in the ICC-approved AMI/Customer Applications pilot program until the conclusion of the 2010 Rate Case. The unrecovered Rider AMP pilot program costs had already been requested in rate base in the 2010 Rate Case. On December 2, 2010, the ICC approved ComEd's request. The investment and the pilot program costs were approved in the 2010 Rate Case proceeding.

ComEd has recognized for accounting purposes its best estimate of any refund obligation, subject to reconciliation when the ICC issues an order in the remand proceedings.

***2010 Illinois Electric Distribution Rate Case.*** On June 30, 2010, ComEd requested ICC approval for an increase of $396 million to its annual delivery services revenue requirement. This request was subsequently reduced to $343 million to account for changes in tax law, corrections, acceptance of limited adjustments proposed by certain parties and the amounts expected to be recovered in the AMI pilot program tariff discussed above. The request to increase the annual revenue requirement was to allow ComEd to recover the costs of substantial investments made since its last rate filing in 2007. The requested increase also reflected increased costs, most notably pension and OPEB, since ComEd's rates were last determined. The original requested rate of return on common equity was 11.5%. In addition, ComEd requested future recovery of certain amounts that were previously recorded as expense that would allow ComEd to recognize a one-time benefit of up to $40 million (pre-tax). The requested increase also included $22 million for increased uncollectible accounts expense, which would increase the threshold for determining over/under recoveries under ComEd's uncollectible accounts tariff.

On May 24, 2011, the ICC issued an order in ComEd's 2010 rate case, which became effective on June 1, 2011. The order approved a $143 million increase to ComEd's annual delivery services revenue requirement and a 10.5% rate of return on common equity. As expected, the ICC followed the Court's position on the post-test year accumulated depreciation issue. The order allowed ComEd to establish or reestablish a net amount of approximately $40 million of previously expensed plant balances or new regulatory assets, which is reflected as a reduction in operating and maintenance expense and income tax expense for the year ended December 31, 2011. The order also affirmed the current regulatory asset for severance costs, which was challenged by an intervenor in the 2010 Rate Case. The order has been appealed to the Court by several parties. ComEd cannot predict the result of these appeals.

***Utility Consolidated Billing and Purchase of Receivables.*** In November 2008, the Illinois Public Utilities Act was amended to require ComEd to file tariffs establishing Utility Consolidated Billing and Purchase of Receivables services. On December 15, 2010, the ICC approved ComEd's tariff offering Purchase of Receivables with Consolidated Billing (PORCB) services for RES. Since the first quarter of 2011, ComEd has been required to buy certain RES receivables, primarily residential and small commercial and industrial customers, at the option of the RES, for electric supply service and then include those amounts on ComEd's bill to customers. Receivables are purchased at a discount to compensate ComEd for uncollectible accounts. ComEd produces consolidated bills for the aforementioned retail customers reflecting charges for electric delivery service and purchased receivables. As of December 31, 2011, the balance of purchased accounts receivable associated with PORCB was $16 million. Under the tariff, ComEd recovers from RES and customers the costs for implementing and operating the program.

***Recovery of Uncollectible Accounts.*** On February 2, 2010, the ICC issued an order adopting tariffs for ComEd to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and amounts collected in rates annually. As a result of the ICC order, ComEd recorded a regulatory asset of $70 million and an offsetting reduction in operating and maintenance expense in the first quarter of 2010 for the cumulative under-collections in 2008 and 2009. In addition, ComEd recorded a one-time charge of $10 million to operating and maintenance expense in the first quarter of 2010 for a contribution to the Supplemental Low-Income Energy Assistance Fund, which is used to assist low-income residential customers.

***Illinois Procurement Proceedings.*** ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, under the Illinois Settlement Legislation, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. In order to fulfill a requirement of the Illinois Settlement Legislation, ComEd hedged the price of a significant portion of energy purchased in the spot market with a five-year variable-to-fixed financial swap contract with Generation that expires on May 31, 2013. On December 21, 2010, the ICC approved the IPA's procurement plan covering the period June 2011 through May 2016. As of December 31, 2011, ComEd had completed the ICC-approved procurement process for its energy requirements through May 2012 as well as a portion of its requirements for each of the years ending in May 2013 and May 2014.

EIMA discussed above contains a provision for the IPA to conduct procurement events for energy and REC requirements for the June 2013 through December 2017 period. ComEd expects that the procurement events will take place during February 2012.

The Illinois Settlement Legislation discussed below requires ComEd to purchase an increasing percentage of its electricity requirements from renewable energy resources. On December 17, 2010, ComEd entered into 20-year contracts with several unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. The long-term renewables purchased will count towards satisfying ComEd's obligation under the state's RPS and all associated costs will be recoverable from customers. As of December 31, 2011, ComEd has completed the ICC-approved procurement process for RECs through May 2012. See Notes 9—Derivative Financial Instruments for additional information regarding ComEd's financial swap contract with Generation and long-term renewable energy contracts.

On May 25, 2010, the ICC approved a Cash Working Capital (CWC) adjustment to be included in ComEd's energy procurement tariff; however, the ICC did not specify the amount of the allowed recovery, which will ultimately be determined in an annual procurement reconciliation proceeding, based on information from ComEd's most recent rate case. The approved CWC adjustment allows ComEd to recover the time value of money between when it is required to pay for supply-related costs and when those funds are actually received from customers. ComEd began billing customers for CWC through its energy procurement rider on June 1, 2010 reflecting the costs included in ComEd's original request to amend the tariff. Because of the uncertainty regarding the amount of CWC recovery, ComEd had been recording a reserve against a portion of these billings. The ICC order in the 2010 Rate Case clarified the method for determining CWC and, as a result, ComEd reversed a $17 million reserve during the second quarter of 2011.

***Illinois Settlement Legislation.*** The Illinois Settlement Legislation was signed into law in August 2007 following a settlement resulting from extensive discussions with legislative leaders in Illinois, ComEd, Generation and other utilities and generators in Illinois to address concerns about higher electric bills without rate freeze, generation tax or other legislation that Exelon believes would be harmful to consumers of electricity, electric utilities, generators of electricity and the State of Illinois. Various Illinois electric utilities, their affiliates and generators of electricity agreed to contribute approximately $1 billion over a period of four years that ended in 2010 to programs to provide rate relief to Illinois electricity customers and funding for the IPA. ComEd committed to issue $64 million in rate relief credits to customers or to fund various programs to assist customers. Generation committed to contribute an aggregate of $747 million, consisting of $435 million to pay ComEd for rate relief programs for ComEd customers, approximately $308 million for rate relief programs for customers of other Illinois utilities and approximately $5 million for partially funding operations of the IPA. The contributions were recognized in the financial statements of Generation and ComEd as rate relief credits were applied to customer bills by ComEd and other Illinois utilities or as operating expenses associated with the programs were incurred. As of December 31, 2010, Generation and ComEd had fulfilled their commitments under the Illinois Settlement Legislation.

During the years ended 2010 and 2009, Generation and ComEd recognized net costs from their contributions pursuant to the Illinois Settlement Legislation in their Consolidated Statements of Operations as follows:

| Year Ended December 31, 2010 | Generation | ComEd | Total Credits Issued to ComEd Customers |
|---|---|---|---|
| Credits to ComEd customers [(a)] | $ 14 | $ 1 | $ 15 |
| Credits to other Illinois utilities' customers [(a)] | 7 | n/a | n/a |
| Total incurred costs | $ 21 | $ 1 | $ 15 |

| Year Ended December 31, 2009 | Generation | ComEd | Total Credits Issued to ComEd Customers |
|---|---|---|---|
| Credits to ComEd customers [(a)] | $ 45 | $ 8 | $ 53 |
| Credits to other Illinois utilities' customers [(a)] | 53 | n/a | n/a |
| Other rate relief programs [(b)] | — | 1 | n/a |
| Total incurred costs | $ 98 | $ 9 | $ 53 |

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

***Energy Efficiency and Renewable Energy Resources.*** As a result of the Illinois Settlement Legislation, electric utilities in Illinois are required to include cost-effective energy efficiency resources in their plans to meet an incremental annual program energy savings requirement of 0.2% of energy delivered to retail customers for the year ended June 1, 2009, which increases annually to 2.0% of energy delivered in the year commencing June 1, 2015 and each year thereafter. Additionally, during the ten-year period that began June 1, 2008, electric utilities must implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers. The energy efficiency and demand response goals are subject to rate impact caps each year. Utilities are allowed recovery of costs for energy efficiency and demand response programs, subject to approval by the ICC. In February 2008, the ICC issued an order approving substantially all of ComEd's initial three-year Energy Efficiency and Demand Response Plan, including cost recovery, covering the period from June 2008 through May 2011. In December 2010, the ICC approved ComEd's second three-year Energy Efficiency and Demand Response Plan covering the period June 2011 through May 2014. The plans are designed to meet the Illinois Settlement Legislation's energy efficiency and demand response goals through May 2014, including reductions in delivered energy to all retail customers and in the peak demand of eligible retail customers.

Since June 1, 2008, utilities have been required to procure cost-effective renewable energy resources in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers. ComEd is also required to acquire amounts of renewable energy resources that will cumulatively increase this percentage to at least 10% by June 1, 2015, with an ultimate target of at least 25% by June 1, 2025, subject to customer rate cap limitations. All goals are subject to rate impact criteria set forth in the Illinois Settlement Legislation. As of December 31, 2011, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates. See Note 18—Commitments and Contingencies for information regarding ComEd's future commitments for the procurement of RECs.

**Pennsylvania Regulatory Matters**

***2010 Pennsylvania Electric and Natural Gas Distribution Rate Cases.*** On December 16, 2010, the PAPUC approved the settlement of PECO's electric and natural gas distribution rate cases, which were filed in March 2010, providing increases in annual service revenue of $225 million and $20 million, respectively. The electric settlement provides for recovery of PJM transmission service costs on a full and current basis through a rider. The approved electric and natural gas distribution rates became effective on January 1, 2011.

In addition, the settlements included a stipulation regarding how tax benefits related to the application of any new IRS guidance on repairs deduction methodology are to be handled from a rate-making perspective. The settlements require that the expected cash benefit from the application of any new guidance to prior tax years be refunded to customers over a seven-year period. On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for electric transmission and distribution property. PECO adopted the safe harbor and elected a method change for the 2010 tax year. The expected total refund to customers for the tax cash benefit from the application of the safe harbor to costs incurred prior to 2010 is $171 million. On October 4, 2011, PECO filed a supplement to its electric distribution tariff to execute the refund to customers of the tax cash benefit related to the IRC Section 481(a) "catch-up" adjustment claimed on the 2010 income tax return, which is subject to adjustment based on the outcome of IRS examinations. Credits will be reflected in customer bills beginning January 1, 2012. Tax benefits claimed prospectively as a result of Revenue Procedure 2011-43 will be reflected as a reduction to income tax expense in the year in which it is claimed on the tax return and will be reflected in the determination of revenue requirements in the next electric distribution base rate case. The IRS anticipates issuing guidance in 2012 on the appropriate tax treatment of repair costs for gas distribution assets. See Note 11 for additional information.

The 2010 electric and natural gas distribution rate case settlements did not specify the rate of return upon which the settlement rates are based, but rather provided for an increase in annual revenue. PECO has not filed a transmission rate case since rates have been unbundled.

***Pennsylvania Procurement Proceedings.*** PECO's PAPUC approved DSP Program, under which PECO is providing default electric service, has a 29-month term that began on January 1, 2011 and ends May 31, 2013. Under the DSP Program, PECO is permitted to recover its electric procurement costs from retail default service customers without mark-up through the GSA. The GSA provides for the recovery of energy, capacity, ancillary costs and administrative costs and is subject to adjustments at least quarterly for any over or under collections. The filing and implementation costs of the DSP Program were recorded as a noncurrent regulatory asset and are being recovered through the GSA over its 29-month term. During 2011, PECO entered into contracts with PAPUC-approved bidders for its fifth and sixth competitive procurements of electric supply for default electric service, which included hourly spot market price full requirements contracts for its large commercial and industrial procurement classes that commenced June 2011, block contracts for the residential procurement class that commenced June and December 2011, and full requirements fixed price contracts for the residential, small and medium commercial procurement classes commencing June 2012. Under the full requirements contracts, default service suppliers must provide electric supply, capacity, transmission other than Network Integration Transmission Service, ancillary services, transmission and distribution losses, congestion management costs and AECs for compliance with the AEPS Act. PECO will conduct three additional competitive procurements over the remainder of the term of the DSP Program.

On April 15, 2011, the PAPUC issued an order approving the joint petition for partial settlement of the initial dynamic pricing and customer acceptance plan and ruled that the administrative costs be recovered from default service customers through the GSA.

On January 13, 2012, PECO filed its second Default Service Plan for approval with the PAPUC. The plan outlined how PECO will purchase electricity for default customers from June 1, 2013 through May 31, 2015. To continue to ensure a competitive procurement process for residential customers, PECO proposed to procure electricity through a combination of one-year and two-year fixed full requirements contracts, reduce the amount of time between when the energy is purchased and when it is provided to customers and complete an annual, rather than quarterly, reconciliation of costs for actual versus forecasted energy use. Hearings on the filing will be held in the summer of 2012, with a PAPUC ruling expected in mid-October 2012.

***Purchase of Receivables Program.*** PECO's revised electric and gas POR programs, approved by the PAPUC in June and December 2010, respectively, require PECO to purchase the customer accounts receivable of EGSs and natural gas suppliers that participate in customer choice programs and have elected consolidated billing by PECO. The revised POR programs provide for full recovery of PECO's system implementation costs for program administration through a temporary discount on purchased receivables and allow PECO to terminate service to customers beginning on the effective date, based on unpaid charges for electric supply or natural gas, and permit recovery of uncollectible accounts expense from customers through distribution rates. PECO's revised electric POR program became effective on January 1, 2011. PECO's gas POR program became effective on January 1, 2012.

Purchased receivables at December 31, 2011 were $47 million, net of an allowance for uncollectible accounts of $5 million. Purchased receivables at December 31, 2010 were $3 million, net of an allowance for uncollectible accounts of less than $1 million. The increase in the purchased receivables balance is a result of increased electric customer choice program participation following the expiration of the transition period. Prior to participation in the customer choice program, these receivables would have been recorded in customer accounts receivable. Purchased receivables are classified in other accounts receivable, net on Exelon's and PECO's Consolidated Balance Sheets.

***Smart Meter and Smart Grid Investments.*** In April 2010, the PAPUC approved PECO's $550 million Smart Meter Procurement and Installation Plan under which PECO will install more than 1.6 million smart meters and deploy advanced communication networks by 2020. Also, in April 2010, PECO entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA of 2009. Under the SGIG, PECO has been awarded $200 million, the maximum grant allowable under the program, for its SGIG project—Smart Future Greater Philadelphia. As a result of the SGIG funding, PECO will deploy 600,000 smart meters by 2013, deploy more than 1.6 million smart meters by 2020 and increase smart grid investments to approximately $100 million by 2013. The $200 million SGIG funds will be reimbursed ratably based on projected spending of more than $400 million, which includes approximately $7 million related to demonstration projects by two sub-recipients. The SGIG is non-taxable based on IRS guidance. The DOE has a conditional ownership interest in Federally-funded project property and equipment, which is subordinate to PECO's existing mortgage. In total, through 2020, PECO plans to spend up to $650 million on its smart grid and smart meter infrastructure. The $200 million SGIG from the DOE will be used to significantly reduce the impact of those investments on PECO ratepayers.

As of December 31, 2011, PECO received $64 million in reimbursements and had $29 million in outstanding receivables from the DOE for reimbursable costs, which are recorded in other accounts receivable, net on Exelon's Consolidated Balance Sheets.

***Energy Efficiency Programs.*** PECO's PAPUC-approved EE&C Plan has a four-year term that began on June 1, 2009 and totals more than $328 million pursuant to Act 129's EE&C reduction targets. The plan sets forth how PECO will reduce electric consumption by 1% and 3% in its service territory by May 31, 2011 and May 31, 2013, respectively and reduce peak demand by a minimum of 4.5% of PECO's annual system peak demand in the 100 hours of highest demand by May 31, 2013, measured against its peak demand during the period of June 1, 2007 through May 31, 2008. If PECO fails to achieve the required reductions in consumption within the stated deadlines, PECO will be subject to civil penalties of up to $20 million, which would not be recoverable from ratepayers.

The plan also includes a CFL program, weatherization programs, an energy efficiency appliance rebate and recycling program and rebates for non-profit, educational, governmental and business customers, customer incentives for energy management programs and incentives to help customers reduce energy demand during peak periods.

As of May 31, 2011, PECO had exceeded the 1% energy use reduction target. On August 18, 2011, the PAPUC approved filed adjustments to the EE&C Plan that will allow PECO to meet its May 31, 2013 targets for energy use and energy demand reductions while remaining within its approved budget.

***Alternative Energy Portfolio Standards.*** In November 2004, Pennsylvania adopted the AEPS Act. The AEPS Act mandated that beginning in 2011, following the expiration of PECO's rate cap transition period, certain percentages of electric energy sold to Pennsylvania retail electric customers shall be generated from certain alternative energy resources as measured in AECs. The requirement for electric energy that must come from Tier I alternative energy resources ranges from approximately 3.5% to 8.0% and the requirement for Tier II alternative energy resources ranges from 6.2% to 10.0%. The required compliance percentages incrementally increase each annual compliance period, which is from June 1 through May 31, until May 31, 2021. These Tier I and Tier II alternative energy resources include acceptable energy sources as set forth in Act 129 and the AEPS Act.

PECO has entered into five-year and ten-year agreements with accepted bidders, including Generation, totaling 452,000 non-solar and 8,000 solar Tier I AECs annually in accordance with a PAPUC approved plan. The plan allowed PECO to bank AECs procured prior to 2011 and use the banked AECs to meet its AEPS Act obligations over two compliance years ending May 2013. The PAPUC also approved the procurement of Tier II AECs and supplemental AECs as well as the sale of excess AECs through independent third party auctions or brokers. In May 2011, PECO procured 340,000 Tier II AECs that are being used to meet AEPS Act obligations for the compliance years ending May 2011 and May 2012. On January 5, 2012, PECO successfully conducted a competitive procurement for 275,000 Tier II AECs to be available toward its AEPS Act obligations for its compliance years ending May 2012 and May 2013, which was approved by the PAPUC on January 17, 2012.

Administrative costs and the costs of the banked AECs were recovered with a return on the unamortized balance over a twelve-month period that ended December, 31, 2011. All AEPS administrative costs and costs of AECs incurred after December 31, 2010 are being recovered on a full and current basis from default service customers through a surcharge.

PECO proposed in its Default Service Plan filed on January 13, 2012 to eliminate the AEPS rider and recover AEPS compliance costs through the GSA.

***Natural Gas Choice Supplier Tariff.*** During 2011, the PAPUC approved PECO's tariff supplements to its Gas Choice Supplier Coordination Tariff and its Retail Gas Service Tariff to address the new licensing requirements for natural gas suppliers (NGS) set forth in the PAPUC's final rulemaking order, which became effective January 1, 2011. The new licensing requirements broaden the types of collateral that PECO can require to mitigate its risk related to an NGS default, as well as PECO's ability to adjust collateral when material changes in supplier creditworthiness occur. PECO has completed its creditworthiness determinations and expects to notify impacted NGSs of their new collateral levels by March 31, 2012.

***Investigation of Pennsylvania Retail Electricity Market.*** On July 28, 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania's retail electric market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed its Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. On December 15, 2011, the PAPUC adopted a final order providing guidance to the state's electric distribution companies in developing their default service plans for the period beginning January 1, 2013. The PAPUC also issued for comment a tentative order describing more detailed recommendations to be implemented prior to the expiration of the electric distribution company's default service plan beginning in 2013, with the exception of a Retail Opt-in Auction Program and Standard Offer Customer Referral Program, which it proposed for inclusion in the 2013 plan. Final guidance on long-term structural changes is expected to be issued in 2012. On January 13, 2012, PECO filed its second Default Service Plan for approval with the PAPUC, which proposed several new programs to continue PECO's support of retail market competition in Pennsylvania in accordance with the order issued by the PAPUC on December 15, 2011.

***Pennsylvania House Bill No. 1294.*** On January 25, 2012, House Bill No. 1294 (HB 1294) was passed by the Pennsylvania State Senate. The House of Representatives approved the legislation through a concurrence vote and now it goes to the Governor for his signature. HB 1294 seeks to clarify the PAPUC's authority to approve alternative ratemaking mechanisms, which would allow for the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems in Pennsylvania.

In order to qualify for the DSIC under HB 1294, utilities are required to submit a long-term infrastructure improvement plan, which will be reviewed by the PAPUC every 5 years, and a certification that a base rate case has been or will be filed within 5 years. The DSIC cannot exceed 5% of distribution rates and will be reset to zero if the utility's return on equity exceeds the allowable rate of return under the DSIC. Utilities can petition the PAPUC for a waiver to the 5% cap.

HB 1294 also includes a provision that allows utilities to use a fully projected future test year under which the PAPUC may permit the inclusion of projected capital costs in rate base for assets that will be placed in service during the future test year.

**Federal Regulatory Matters**

***Transmission Formula Rate.*** ComEd's transmission rates are established based on a FERC-approved formula. ComEd's most recent annual formula rate update filed in May 2011 reflects actual 2010 expenses and investments plus forecasted 2011 capital additions. The update resulted in a revenue requirement of $438 million offset by a $16 million reduction related to the reconciliation of 2010 actual costs for a net revenue requirement of $422 million. This compares to the May 2010 updated revenue requirement of $416 million. The increase in the revenue requirement was primarily driven by the Illinois income tax statutory rate change enacted in January 2011. The 2011 net revenue requirement became effective June 1, 2011 and is recovered over the period extending through May 31, 2012. The regulatory liability associated with the true-up is being amortized as the associated amounts are refunded.

ComEd's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 9.10%, a decrease from the 9.27% return previously authorized. The decrease in return was primarily due to lower interest rates on ComEd's long-term debt outstanding. As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.5% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the formula transmission rate is currently capped at 55%.

***PJM Transmission Rate Design and Operating Agreements.*** PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd and PECO incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. In the short term, based on new transmission facilities approved by PJM, it is likely that allocating across PJM the costs of new facilities 500 kV and above will increase charges to ComEd and reduce charges to PECO, as compared to the allocation methodology in effect before the FERC order. After FERC ultimately denied all requests for rehearing on all issues, several parties filed petitions in the U.S. Court of Appeals for the Seventh Circuit for review of the decision. On August 6, 2009, that court issued its decision affirming FERC's order with regard to the costs of existing facilities but reversing and remanding to FERC for further consideration its decision with regard to the costs of new facilities 500 kV and above. On January 21, 2010, FERC issued an order establishing paper hearing procedures to supplement the record. In May and June 2010, certain parties, including Exelon, submitted testimony to supplement the record. ComEd anticipates that all impacts of any rate design changes effective after December 31, 2006 should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on ComEd's results of operations, cash flows or financial position. PECO anticipates that all impacts of any rate design changes should be recoverable through the transmission service charge rider approved in PECO's 2010 electric distribution rate case settlement and, thus, the rate design changes are not expected to have a material impact on PECO's results of operations, cash flows or financial position. To the extent any rate design changes are retroactive to periods prior to January 1, 2011 there may be an impact on PECO's results of operations.

ComEd and PECO are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. ComEd and PECO will work with PJM to continue to evaluate the scope and timing of any required construction projects. ComEd and PECO's estimated commitments are as follows:

| | Total | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|
| ComEd | $242 | $73 | $104 | $41 | $12 | $12 |
| PECO | 87 | 30 | 18 | 12 | 13 | 14 |

***PJM Minimum Offer Price Rule.*** PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. On February 1, 2011, in response to the enactment of New Jersey Senate Bill 2381, Generation joined a group of generating companies, PJM Power Providers Group (P3), in filing a complaint asking FERC to revise PJM's MOPR to mitigate this exercise of buyer market power. In response to P3's complaint, PJM filed a tariff amendment on February 11, 2011, to improve the MOPR. PJM's filing differs from P3's proposal, but in general P3 supports PJM's filing. P3 and PJM requested that FERC act on the proposed tariff amendment prior to the May 2011 capacity auction. A number of state regulators and consumer groups have opposed tariff changes, but these changes are in line with recent FERC orders regarding capacity markets in the New York and New England ISOs. On April 12, 2011, FERC issued an order revising PJM's MOPR to mitigate the exercise of buyer market power. Included in the FERC order was a revision to the MOPR whereby a subsidized plant cannot submit a bid into the auction for less than 90% of the cost of new entry of a plant of that type, unless the unit can justify a lower bid based on its costs. The minimum offer limitation continues until a unit clears the base residual RPM auction for the first time. After a unit clears once, it may bid in at any price, including zero. This may help reduce the magnitude of artificial suppression of capacity auction prices created by the actions of state regulators such as the capacity legislation in New Jersey. A number of parties filed rehearing of the FERC order on several different issues, including the question of whether the minimum price mitigation should apply to load serving entities that self-supply capacity. FERC scheduled the issue for consideration at a technical conference, while rehearing is pending. On November 17, 2011, the Commission issued an order on rehearing, that, among other things, denied rehearing on the central issues, including application of the MOPR to self-supply capacity and to state sponsored capacity. A number of parties filed petitions for review in the Courts of Appeals for the D.C. Circuit and the Third Circuit, all of which are currently pending in the Third Circuit. The case likely will not be resolved by the Court until the second half of 2012 or early 2013.

***Market-Based Rates.*** Generation, ComEd and PECO are public utilities for purposes of the Federal Power Act and are required to obtain FERC's acceptance of rate schedules for wholesale electricity sales. Currently, Generation, ComEd and PECO have authority to execute wholesale electricity sales at market-based rates. As is customary with market-based rate schedules, FERC has reserved the right to suspend market-based rate authority on a retroactive basis if it subsequently determines that Generation, ComEd or PECO has violated the terms and conditions of its tariff or the Federal Power Act. FERC is also authorized to order refunds if it finds that the market-based rates are not just and reasonable under the Federal Power Act.

As required by FERC's regulations, as promulgated in the Order No. 697 series, Generation, ComEd and PECO have filed market power analyses using the prescribed market share screens to demonstrate that Generation, ComEd and PECO qualify for market-based rates in the regions where they are selling energy and capacity under market-based rate tariffs. FERC accepted the 2008 filings on January 15, 2009 and September 2, 2009 and accepted the 2009 filing on October 26, 2009, affirming Exelon's affiliates continued right to make sales at market-based rates. These analyses must examine historic test period data and must be updated every three years on a prescribed schedule. The most recent updated analysis for the PJM and Northeast Regions was filed in late 2010, based on 2009 historic test period data. In that updated analysis, Generation informed FERC that its market share data in PJM would change beginning in 2011, when Generation's contract for PECO's full requirements for capacity and energy expired. The FERC Staff asked for a letter describing the amount of capacity affected by the PECO contract expiration and alternative transactions, which Generation filed on March 21, 2011. The impact of that change, as well as any new sales contracts or other intervening changes in Generation's market share, will be reflected in the next updated market share screen analysis due to be filed at the end of 2013. On June 22, 2011, FERC issued an order confirming Generation's continued authority to charge market based rates, stating that any market power concerns are adequately addressed by PJM's monitoring and mitigation programs.

***Reliability Pricing Model.*** PJM's RPM auctions take place 36 months ahead of the scheduled delivery year. The most recent auction for the delivery year ending May 31, 2015 occurred in May 2011. While certain state commissions, consumer advocates and trade associations continue to object to the PJM capacity market construct, their most recent challenge to auction results ran its course when the D. C. Circuit, on February 8, 2011, denied a petition to review the Commission's dismissal of their complaint.

***License Renewals.*** On April 8, 2009, the NRC issued a renewed operating license for Oyster Creek that expires in April 2029. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. See Note 18—Commitments and Contingencies for additional information.

On June 30, 2011, the NRC issued the renewed operating licenses for Salem Units 1 and 2 expiring in 2036 and 2040, respectively. Exelon is a 42.59% owner of the Salem Units.

On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years. The NRC is expected to spend a total of 22 to 30 months to review the applications before making a decision. The current operating licenses for Limerick Units 1 and 2 expire in 2024 and 2029, respectively.

### Regulatory Assets and Liabilities

Exelon, ComEd and PECO prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

The following tables provide information about the regulatory assets and liabilities of Exelon as of December 31, 2011 and 2010.

| December 31, 2011 | |
|---|---|
| **Regulatory assets** | |
| Pension and other postretirement benefits | $2,998 |
| Deferred income taxes | 1,181 |
| AMI and smart meter programs | 30 |
| Under-recovered distribution services costs | 84 |
| Debt costs | 99 |
| Severance | 63 |
| Asset retirement obligations | 74 |
| MGP remediation costs | 159 |
| RTO start-up costs | 7 |
| Financial swap with Generation—noncurrent | — |
| Renewable energy and associated RECs—noncurrent | 97 |
| DSP Program costs | 5 |
| Other | 42 |
| Noncurrent regulatory assets | 4,839 |
| Financial swap with Generation—current | — |
| Under-recovered energy and transmission costs | 57 |
| Under-recovered electric universal service fund costs | 3 |
| Renewable energy and associated RECs—current | 9 |
| Current regulatory assets | 69 |
| Total regulatory assets | $4,908 |

| | |
|---|---|
| **Regulatory liabilities** | |
| Nuclear decommissioning | $2,222 |
| Removal costs | 1,246 |
| Energy efficiency and demand response programs | 118 |
| Electric distribution tax repairs | 170 |
| Over-recovered uncollectible accounts | 15 |
| Noncurrent regulatory liabilities | 3,771 |
| Over-recovered energy and transmission costs | 42 |
| Over-recovered gas universal service fund costs | 3 |
| Over-recovered AEPS costs | 8 |
| Current regulatory liabilities | 53 |
| Total regulatory liabilities | $3,824 |

**December 31, 2011**

| | |
|---|---|
| **Regulatory assets** | |
| Pension and other postretirement benefits | $2,763 |
| Deferred income taxes | 852 |
| AMI and smart meter program expenses | 17 |
| Debt costs | 123 |
| Severance | 74 |
| Asset retirement obligations | 86 |
| MGP remediation costs | 149 |
| RTO start-up costs | 10 |
| Under-recovered uncollectible accounts | 14 |
| Financial swap with Generation—noncurrent | — |
| DSP Program costs | 7 |
| Other | 45 |
| Noncurrent regulatory assets | 4,140 |
| Financial swap with Generation—current | — |
| Under-recovered energy and transmission costs | 6 |
| DSP Program electric procurement contracts | 4 |
| Current regulatory assets | 10 |
| Total regulatory assets | $4,150 |
| **Regulatory liabilities** | |
| Nuclear decommissioning | $2,267 |
| Removal costs | 1,211 |
| Renewable energy and associated RECs—noncurrent | 4 |
| Energy efficiency and demand response programs | 69 |
| Other | 4 |
| Noncurrent regulatory liabilities | 3,555 |
| Over-recovered energy and transmission costs | 44 |
| Current regulatory liabilities | 44 |
| Total regulatory liabilities | $3,599 |

***Pension and other postretirement benefits.*** As of December 31, 2011, $2,991 million represents regulatory assets related to the recognition of ComEd's and PECO's respective shares of the underfunded status of Exelon's defined benefit postretirement plans as a liability on Exelon's balance sheet. The regulatory asset is amortized in proportion to the recognition of prior service costs (gains), transition obligations and actuarial losses attributable to ComEd's pension plan and ComEd's and PECO's other postretirement benefit plans determined by the cost recognition provisions of the authoritative guidance for pensions and postretirement benefits. ComEd and PECO will recover these costs through base rates as allowed in their most recently approved regulated rate orders. See Note 13 –Retirement Benefits for additional detail. In addition, $7 million is the result of PECO transitioning to the current authoritative guidance in 1993, which is recoverable in rates through 2012. ComEd and PECO are not earning a return on the recovery of these costs in base rates.

***Deferred income taxes.*** These costs represent the difference between the method by which the regulator allows for the recovery of income taxes and how income taxes would be recorded under GAAP. Regulatory assets and liabilities associated with deferred income taxes, recorded in compliance with the authoritative guidance for accounting for certain types of regulation and income taxes, include the deferred tax effects associated principally with liberalized depreciation accounted for in accordance with the ratemaking policies of the ICC and PAPUC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future transmission and distribution rates. For ComEd, this amount includes the impacts of a reduction in the deductibility, for Federal income tax purposes, of certain retiree health care costs pursuant to the March 2010 Health Care Reform Acts. ComEd was granted recovery of these additional income taxes on May 24, 2011 in the ICC's 2010 Rate Case order. The recovery period for these costs is through May 31, 2014. See Note 11—Income Taxes and Note 13—Retirement Benefits for additional information. ComEd and PECO are not earning a return on the recovery of these costs.

***AMI and smart meter programs.*** For ComEd, this amount represents operating and maintenance expenses and meter costs associated with ComEd's AMI pilot program approved in the May 24, 2011 ICC order in ComEd's 2010 rate case. The recovery periods for operating and maintenance expenses and meter costs are through May 31, 2014 and January 1, 2020, respectively. ComEd is earning a return on the meter costs. For PECO, this amount represents accelerated depreciation and filing and implementation costs relating to the PAPUC-approved Smart Meter Procurement and Installation Plan as well as the return on the un-depreciated investment, taxes, and operating and maintenance expenses. The approved plan allows for recovery of filing and implementation costs incurred through December 31, 2010 during 2011 and 2012. In addition, the approved plan provides for recovery of program costs, which includes depreciation on new equipment placed in service, beginning in January 2011 on full and current basis, which includes interest income or expense on the under or over recovery, and recovery of accelerated depreciation on PECO's current meter assets over a 10-year period ending December 31, 2020.

***Under-recovered distribution services costs.*** Under EIMA, which became effective in the fourth quarter of 2011, ComEd is allowed recovery of distribution services costs through a formula rate tariff. The legislation provides for an annual reconciliation of the revenue requirement in effect to reflect the actual costs that the ICC determines are prudently and reasonably incurred in a given year. The reconciliation will be recovered through rates over a one-year period, beginning in January 2013 for the 2011 annual reconciliation period. The regulatory asset also includes costs associated with certain one-time events, such as large storms, which will be recovered over a five-year period beginning in January 2013. ComEd is earning a return on these costs. As of December 31, 2011, the regulatory asset was comprised of $29 million for the annual reconciliation and $55 million related to significant storms.

***Debt costs.*** Consistent with rate recovery for ratemaking purposes, ComEd's and PECO's recoverable losses on reacquired long-term debt related to regulated operations are deferred and amortized to interest expense over the life of the new debt issued to finance the debt redemption or over the life of the original debt issuance if the debt is not refinanced. Interest-rate swap settlements are deferred and amortized over the period that the related debt is outstanding or the life of the original issuance retired. These debt costs are used in the determination of the weighted cost of capital applied to rate base in the rate-making process.

***Severance.*** These costs represent previously incurred severance costs that ComEd was granted recovery of in the December 20, 2006 ICC rehearing rate order and the May 24, 2011 ICC order in ComEd's 2010 rate case. The recovery periods are through June 30, 2014 and May 31, 2014, respectively. ComEd is not earning a return on these costs.

***Asset retirement obligations.*** These costs represent future removal costs associated with ComEd's and PECO's existing asset retirement obligations. PECO will begin to earn a return on, and a recovery of, these costs once the removal activities have been performed. ComEd will recover these costs through future depreciation expense and will earn a return on these costs once the removal activities have been performed. See Note 12—Asset Retirement Obligations for additional information.

***MGP remediation costs.*** Recovery of these items was granted to ComEd in the July 26, 2006 ICC rate order. For PECO, these costs are recoverable through rates as affirmed in the 2010 approved natural gas distribution rate case settlement. The period of recovery for both ComEd and PECO will depend on the timing of the actual expenditures. ComEd and PECO are not earning a return on the recovery of these costs. See Note 18—Commitments and Contingencies for additional information.

***RTO start-up costs.*** Recovery of these RTO start-up costs was approved by FERC. The recovery period is through March 31, 2015. ComEd is earning a return on these costs.

***Under (Over)-recovered uncollectible accounts.*** As a result of the February 2010 ICC order approving recovery of ComEd's uncollectible accounts, ComEd has the ability to adjust its rates annually to reflect the increases and decreases in annual uncollectible accounts expense starting with year 2008. ComEd recorded a regulatory asset for the cumulative under-collections in 2008 and 2009. Recovery of the initial regulatory asset was completed over an approximate 14-month time frame which began in April 2010. The recovery or refund of the difference in the uncollectible accounts expense applicable to the years starting with January 1, 2010, will take place over a 12-month time frame beginning in June of the following year. ComEd is not earning a return on these costs.

***Financial swap with Generation.*** To fulfill a requirement of the Illinois Settlement Legislation, ComEd entered into a five-year financial swap contract with Generation that expires on May 31, 2013. Since the swap contract was deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period are recorded by ComEd as well as an offsetting regulatory asset or liability. ComEd does not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd's cost to purchase energy on the spot market and the contracted price. In Exelon's consolidated financial statements, the fair value of the intercompany swap recorded by Generation and ComEd is eliminated.

***Renewable Energy and Associated RECs.*** On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts begins in June 2012. 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 as well as an offsetting regulatory asset or liability are recorded by ComEd. ComEd does not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd's cost to purchase energy on the spot market and the contracted price.

***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, September 10, 2008 and May 24, 2011. The recovery period for the two former rate case costs was through September 15, 2011. The recovery period for the 2010 Rate Case costs is through May 31, 2014. Pursuant to the approved settlements of the 2010 electric and natural gas distribution rate cases, PECO is allowed recovery of rate case costs over two years ending December 31, 2012. ComEd and PECO do not earn a return on the recovery of these costs.

***DSP Program costs.*** These amounts represent recoverable administrative costs incurred relating to filing, procurement, and information technology improvements associated with PECO's PAPUC-approved DSP Program for the procurement of electric supply following the expiration of PECO's generation rate caps on December 31, 2010. The filing and implementation costs of this DSP Program are recoverable through the GSA over its 29-month term, beginning January 1, 2011. The independent evaluator costs associated with conducting procurements is recoverable over a 12-month period after the PAPUC approves the results of the procurements. Costs relating to information technology improvements are recoverable over a 5-year period beginning January 1, 2011. PECO earns a return on the recovery of information technology costs.

***Under (Over)-recovered energy and transmission costs current asset (liability).*** Starting in 2007, ComEd's energy and transmission costs are recoverable (refundable) under ComEd's ICC and/or FERC-approved rates. ComEd earns interest on under-recovered costs and pays interest on over- recovered costs to customers. The PECO energy costs represent the electric and gas supply related costs recoverable (refundable) under PECO's GSA and PGC, respectively. PECO earns interest on the under-recovered energy and natural gas costs and pays interest on over-recovered energy and natural gas costs to customers. The PECO transmission costs represent the electric transmission costs recoverable (refundable) under the TSC under which PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2011, PECO had a regulatory asset related to under-recovered transmission costs of $9 million and a regulatory liability that included $25 million related to over-recovered electric supply costs under the GSA and $5 million related to over-recovered natural gas supply costs under the PGC.

***Nuclear decommissioning.*** These amounts represent estimated future nuclear decommissioning costs that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. Exelon believes the trust fund assets, including prospective earnings thereon and any future collections from customers, will equal the associated future decommissioning costs at the time of decommissioning. See Note 12—Asset Retirement Obligations for additional information.

***Removal costs.*** These amounts represent funds ComEd has received from customers to cover the future removal of property, plant and equipment which reduces rate base for ratemaking purposes.

***Energy efficiency and demand response programs.*** These amounts represent costs recoverable (refundable) under ComEd's ICC approved Energy Efficiency and Demand Response Plan and PECO's PAPUC-approved EE&C Plan. ComEd began recovering these costs or refunding over-collections of these costs on June 1, 2008 through a rider. ComEd earns a return on the capital investment incurred under the program but does not earn (pay) interest on under (over) collections. PECO began recovering these costs through a rider in January 2010 based on projected spending under the program. Recovery will continue over the life of the program, which expires on May 31, 2013. Excess funds collected are required to be refunded no later than six months following the expiration of the program.

***Electric distribution tax repairs.*** PECO' 2010 electric distribution rate case settlement required that the expected cash benefit from the application of Revenue Procedure 2011-43, which was issued on August 19, 2011, to prior tax years be refunded to customers over a seven-year period. Credits will be reflected in customer bills beginning January 1, 2012. No interest will be paid to customers.

***Under (Over)-recovered universal service fund costs.*** The universal service fund cost is a recovery mechanism that allows PECO to recover discounts issued to electric and gas customers enrolled in assistance programs. As of December 31, 2011, PECO was under-recovered for its electric program and over-recovered for its gas program. PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers.

***Under (Over)-recovered AEPS costs current asset (liability).*** The AEPS costs represent the administrative and AEC costs incurred to comply with the requirements of the AEPS Act, which are recoverable on a full and current basis. PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers.

**Operating and Maintenance for Regulatory Required Programs**

The following tables set forth costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through a rider for ComEd and PECO for the years ended December 31, 2011, 2010 and 2009. An equal and offsetting amount has been reflected in operating revenues during the periods.

| | For the year ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Energy efficiency and demand response programs (a) | 162 | 135 | 59 |
| Smart meter program | 9 | 5 | — |
| Purchased power administrative costs | 10 | 4 | 4 |
| AEPS administrative costs | 1 | — | — |
| Consumer education program | 2 | 3 | — |
| Total operating and maintenance for regulatory required programs | 184 | 147 | 63 |

(a) As a result of the Illinois Settlement, utilities are required to provide energy efficiency and demand response programs.

**3. Merger and Acquisitions**

**Proposed Merger with Constellation Energy Group, Inc.**

On April 28, 2011, Exelon and Constellation announced that they signed an agreement and plan of merger to combine the two companies in a stock-for-stock transaction. Under the merger agreement, Constellation's shareholders will receive 0.930 shares of Exelon common stock in exchange for each share of Constellation common stock. Based on Exelon's closing share price on April 27, 2011, Constellation shareholders would receive $7.9 billion in total equity value. The resulting company will retain the Exelon name and be headquartered in Chicago. The transaction requires the approval by the shareholders of both Exelon and Constellation. Completion of the transaction is also conditioned upon review of the transaction by the DOJ and approval by the FERC, NRC, Maryland Public Service Commission (MDPSC), the New York Public Service Commission (NYPSC), the Public Utility Commission of Texas (PUCT), and other state and federal regulatory bodies. As of February 9, 2012, Exelon and Constellation have received approval of the transaction from the shareholders of Exelon and Constellation, DOJ, PUCT and the NYPSC. Exelon and Constellation are awaiting final approval of the transaction from the MDPSC, FERC and NRC.

On January 30, 2012, FERC published a notice on its website regarding a non-public investigation of certain of Constellation's power trading activities in and around the New York ISO from September 2007 through December 2008. Exelon continues to evaluate the matter in order to make an assessment regarding (1) the likely outcome of the investigation and (2) whether the ultimate resolution of the investigation will be material to the results of operations, cash flows, or financial condition of Constellation before the merger or Exelon after the merger. Absent any delay in the FERC approval process, the companies anticipate closing the transaction in the first quarter of 2012.

Associated with certain of the regulatory approvals required for the merger, the companies have proposed to divest three Constellation generating stations located in PJM, which is the only market where there is a material overlap of generation owned by both companies. These stations, Brandon Shores and H.A. Wagner in Anne Arundel County, Maryland, and C.P. Crane in Baltimore County, Maryland, include base-load, coal-fired generation units plus associated gas/oil units located at the same sites, and total 2,648 MW of generation capacity. In October 2011, Exelon and Constellation reached a settlement with the PJM Independent Market Monitor, who had previously raised market power concerns regarding the merger. The settlement contains a number of commitments by the merged company, including limiting the universe of potential buyers of the divested assets to entities without significant market shares in the relevant PJM markets. The settlement also includes assurances about how the merged company will bid its units into the PJM markets. The proposed divestiture and the settlement with the PJM Market Monitor were filed with FERC and the MDPSC and are included in their decisions to issue a final order approving the merger.

In December 2011, Exelon and Constellation reached a settlement with the State of Maryland and the City of Baltimore and other interested parties in connection with the regulatory proceedings pending before the MDPSC. As part of this settlement and the application for approval of the merger by MDPSC, Exelon and Constellation have proposed a package of benefits to Baltimore Gas and Electric Company (BGE) customers, the City of Baltimore and the state of Maryland, which results in a direct investment in the state of Maryland of more than $1 billion. This investment includes capital projects including development of new renewable and gas-fired generation in Maryland, representing a substantial portion of the investment.

In addition, in January 2012 Exelon and Constellation reached an agreement with Electricite de France (EDF) under which EDF has withdrawn its opposition to the Exelon-Constellation merger. The terms address Constellation Energy Nuclear Group (CENG), a joint venture between Constellation and EDF that owns and operates three nuclear facilities with five generating units in Maryland and New York. The agreement reaffirms the terms of the joint venture. The agreement did not include any exchange of monetary consideration and Exelon does not expect the agreement will have a significant impact on Exelon and Generation's future results of operations, financial position and cash flows.

Exelon was named in suits filed in the Circuit Court of Baltimore City, Maryland alleging that individual directors of Constellation breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. Similar suits were also filed in the United States District Court for the District of Maryland. The suits sought to enjoin a Constellation shareholder vote on the proposed merger until all material information is disclosed and sought rescission of the proposed merger. During the third quarter, the parties to the suits reached an agreement in principle to settle the suits through additional disclosures to Constellation shareholders. The settlement is subject to court approval.

Through December 31, 2011, Exelon has incurred approximately $77 million of expense associated with the transaction, primarily related to fees incurred as part of the acquisition. Under the merger agreement, in the event Exelon or Constellation terminates the merger agreement to accept a superior proposal, or under certain other circumstances, Exelon or Constellation, as applicable, would be required to pay a termination fee of $800 million in the case of a termination fee payable by Exelon to Constellation or a termination fee of $200 million in the case of a termination fee payable by Constellation to Exelon.

**Acquisitions**

Consistent with the applicable accounting guidance, the fair value of the assets acquired and liabilities assumed was determined as of the acquisition date through the use of significant estimates and assumptions that are judgmental in nature. Some of the more significant estimates and assumptions used include: projected future cash flows (including the amount and timing); discount rates reflecting the risk inherent in the future cash flows; future power and fuel market prices. Additionally, market prices based on the Market Price Referent (MPR) established by the CPUC for renewable energy resources were used in determining the fair value of the Antelope Valley assets acquired and liabilities assumed. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and the duration of the liabilities assumed. Generation did not record any goodwill related to any of the respective acquisitions.

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for each of the companies acquired by Generation during the years ended December 31, 2011 and December 31, 2010:

| | Acquisitions | | | |
|---|---|---|---|---|
| | 2011 | | | 2010 |
| | Wolf Hollow | Antelope Valley | Shooting Star | Exelon Wind |
| **Fair value of consideration transferred** | | | | |
| Cash | $305 | $ 75 | $ 3 | $893 |
| Plus: Gain on PPA settlement | 6 | — | — | — |
| Contingent consideration [(a)] | — | — | 9 | 32 |
| **Total fair value of consideration transferred** | $311 | $ 75 | $ 12 | $925 |
| **Recognized amounts of identifiable assets acquired and liabilities assumed** | | | | |
| Property, plant and equipment | $347 | $ 15 | $ 12 | $700 |
| Inventory | 5 | — | — | — |
| Intangible assets [(b)] | — | 190 | — | 224 |
| Payable to First Solar, Inc. [(c)] | — | (135) | — | — |
| Working capital, net [(d)] | (5) | — | — | 18 |
| Asset retirement obligations | — | — | — | (13) |
| Noncontrolling interest | — | — | — | (3) |
| Other Assets | — | 5 | — | (1) |
| Total net identifiable assets | $347 | $ 75 | $ 12 | $925 |
| Bargain purchase gain | $ 36 | $ — | $— | $— |

(a) For the Shooting Star acquisition, the balance includes $4 million of cash placed in escrow which will be paid to Infinity Wind Holdings, LLC upon commencement of construction.

(b) See Note 7—Intangible Assets for additional information.

(c) Generation concluded that the remaining, yet-to-be paid $135 million in consideration was embedded in the amounts payable under the Engineering, Procurement, Construction (EPC) agreement for First Solar, Inc. to construct the solar facility. For accounting purposes, this aspect of the transaction is considered to be akin to a "seller financing" arrangement. As such, Generation recorded a liability of $135 million associated with the portion of the future payments to First Solar, Inc. under the EPC agreement to reflect Generation's implicit amounts due First Solar, Inc. for the remainder of the value of the net assets acquired. The $135 million payable to First Solar, Inc. will be relieved as Generation makes payments for costs incurred over the project construction period.

(d) Working capital acquired for Wolf Hollow is subject to a 180-day adjustment period.

**Wolf Hollow, LLC.** On August 24, 2011, Generation completed the acquisition of all of the equity interests of Wolf Hollow, LLC (Wolf Hollow), a combined-cycle, natural gas-fired power plant in north Texas, pursuant to which Generation added 720 MWs of capacity within the ERCOT power market. The acquisition supports the Exelon commitment to clean energy as part of Exelon 2020. In connection with the acquisition, Generation terminated and settled its existing long-term PPA with Wolf Hollow, resulting in a gain of approximately $6 million, which is included within operating revenues (other revenue) in Exelon's Consolidated Statements of Operations and Comprehensive Income.

Generation recognized an approximately $36 million non-cash bargain purchase gain (i.e., negative goodwill). Increases in observable forward market power prices since the May 2011 transaction announcement date, primarily reflecting the impact on the Texas power markets of the CSAPR final regulations issued by the EPA in July 2011, as well as sustained hot weather in Texas, resulted in an increase in the fair value of the net assets as of the acquisition date, resulting in the bargain purchase gain. The gain was included within other, net in Exelon's Consolidated Statements of Operations and Comprehensive Income.

The fair value of the assets acquired included receivables for insurance claims of $14 million shown in working capital above. This amount represents insured repair costs incurred prior to the acquisition date, less the applicable deductible. As of December 31, 2011, approximately $4 million remains outstanding, which Generation expects to collect during the first quarter of 2012.

Wolf Hollow's revenue and operating income contribution to Exelon and Generation for the period from August 25, 2011 to December 31, 2011 was approximately $30 million and $(5) million, respectively. The unaudited pro forma results for Exelon and Generation as if the Wolf Hollow acquisition occurred on January 1, 2010 were not materially different from Exelon and Generation's financial results for the years ended December 31, 2011 and 2010. Exelon and Generation incurred approximately $4 million of acquisition-related costs associated with this transaction. These costs are included within operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.

**Antelope Valley Solar Ranch One.** On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which developed and will build, operate, and maintain the project. Construction has started, with the first portion of the project expected to come online in late 2012 and full operation planned for late 2013. The acquisition supports the Exelon commitment to clean energy as part of Exelon 2020. The project has a 25-year PPA, approved by the California Public Utilities Commission (CPUC), with Pacific Gas & Electric Company for the full output of the plant.

Exelon expects to invest up to $713 million in equity in the project through 2013. The DOE's Loan Programs Office issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing Bank to support the financing of the construction of the project. An initial DOE Loan advance was expected to be made during the fourth quarter of 2011, but was delayed by the DOE pending resolution of an outstanding construction permit issue. While the construction permit may constitute a technical default under the loan guarantee agreement, based on discussions with the governmental body that issued the permit, Exelon believes a ministerial change to the permit should resolve the issue. DOE was notified of this issue and has extended to April 6, 2012 the date by which the initial loan advance must be funded. See Note 10 – Debt and Credit Agreements for additional information on the DOE loan guarantee. The original purchase agreement also contained a provision that First Solar, Inc. will repurchase Antelope Valley if initial funding of the loan does not occur by January 10, 2012. However, the purchase agreement has been amended to extend this date to February 24, 2012 or such later date as may be agreed by Exelon and First Solar, Inc. If this date is not extended further, First Solar, Inc. would repurchase Antelope Valley for the purchase price paid by Exelon and certain other costs incurred by Exelon related to the project.

In 2011, Exelon and Generation incurred approximately $8 million of acquisition-related costs associated with this transaction. These costs are included within operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.

**Shooting Star Wind Project, LLC.** On December 7, 2011, Exelon Wind and Infinity Wind Holdings, LLC (Infinity Wind) entered into a purchase agreement by which Exelon Wind purchased all of the membership interests in Shooting Star Wind Project, LLC (Shooting Star), a 104-MW wind power generation project in Kiowa County, Kansas. Shooting Star is in the development stage and backed by a 20-year PPA with Mid-Kansas Electric Company for 100% of the net energy, capacity, ancillaries, and green tags produced. The project will require a total investment of approximately $148 million and is expected to achieve commercial operation in the fourth quarter of 2012.

**Exelon Wind.** On December 9, 2010, Generation completed the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind), a leading operator and developer of wind power. Under the terms of the agreement, Generation added 735 MWs of installed, operating wind capacity located in eight states. The acquisition supports Exelon's commitment to renewable energy as part of Exelon 2020.

The contingent consideration arrangement requires that Generation pay up to $40 million related to three individual projects with an aggregate capacity of 230 MWs, contingent upon meeting certain contractual commitments related to the commencement of construction of each project. The fair value of the contingent consideration arrangement of $32 million was determined as of the acquisition date based upon a weighted average probability of meeting certain contractual commitments related to the commencement of construction of each project, which is considered an unobservable (Level 3) input pursuant to applicable accounting guidance. During the third quarter of 2011, $16 million of contingent consideration was paid to Deere & Company for one of the projects and the probability of a second project beginning construction, Harvest II, was increased to 100%. As a result, $2 million was recorded in operating and maintenance expense within Exelon's Consolidated Statements of Operations and Comprehensive Income and the contingent consideration included within other current liabilities within Exelon's Consolidated Balance Sheets was adjusted to $10 million to reflect the full expected contingent payment related to the Harvest II project. The remaining $8 million of contingent consideration is included in other current liabilities within Exelon's Consolidated Balance Sheets.

The fair value of the assets acquired included customer receivables of $18 million. There are no outstanding customer receivables that were acquired in the Exelon Wind transaction.

The $3 million noncontrolling interest represents the noncontrolling members' proportionate share in the fair value of the assets acquired and liabilities assumed in the transaction.

The unaudited pro forma results for Exelon and Generation prepared as if the Exelon Wind acquisition occurred on January 1, 2009 were not materially different from Exelon's and Generation's financial results for the years ended December 31, 2010 and 2009.

### 4. Accounts Receivable

Accounts receivable at December 31, 2011 and 2010 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:

| | 2011 | 2010 |
|---|---|---|
| Unbilled customer revenues | 902 | 1,060 |
| Allowance for uncollectible accounts (a)(b) | (199) | (211) |

(a) Includes the allowance for uncollectible accounts on customer and other accounts receivable.
(b) Includes an allowance for uncollectible accounts of $8 million and $2 million at PECO as of December 31, 2011 and December 31, 2010, respectively, related to PECO's current installment plan receivables described below.

***PECO Installment Plan Receivables.*** PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $21 million and $22 million as of December 31, 2011 and December 31, 2010, respectively. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1 – Significant Accounting Policies. The allowance for uncollectible accounts balance associated with these receivables at December 31, 2011 of $17 million consists of $1 million, $3 million and $13 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2010 of $19 million consists of $1 million, $5 million and $13 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of December 31, 2011 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1—Significant Accounting Policies.

***Accounts Receivable Agreement.*** PECO is party to an agreement with a financial institution under which it sold an undivided interest, adjusted daily, in up to $225 million of designated accounts receivable, which is accounted for as a secured borrowing. As of December 31, 2011 and December 31, 2010, the financial institution's undivided interest in Exelon and PECO's gross accounts receivable was equivalent to $329 million and $346 million, respectively, which is calculated under the terms of the agreement. See Note 10—Debt and Credit Agreements for additional information regarding the accounts receivable agreement.

### 5. Property, Plant and Equipment

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2011 and 2010:

| | Average Service Life (years) | 2011 | 2010 |
|---|---|---|---|
| **Asset Category** | | | |
| Electric—transmission and distribution | 5 -75 | $21,716 | $20,389 |
| Electric—generation [(a)] | 1 -54 | 13,682 | 11,914 |
| Gas—transportation and distribution | 5 -70 | 1,793 | 1,732 |
| Common—electric and gas | 5 -50 | 564 | 534 |
| Nuclear fuel [(b)] | 1 - 8 | 4,225 | 3,725 |
| Construction work in progress | N/A | 1,110 | 1,290 |
| Other property, plant and equipment [(c)] | 4 -50 | 439 | 421 |
| Total property, plant and equipment | | 43,529 | 40,005 |
| Less: accumulated depreciation [(d)] | | 10,959 | 10,064 |
| Property, plant and equipment, net | | $32,570 | $29,941 |

(a) Includes assets acquired through acquisitions. See Note 3—Acquisition for additional information.

(b) Includes nuclear fuel that is in the fabrication and installation phase of $674 million and $651 million at December 31, 2011 and 2010, respectively.

(c) Includes Generation's buildings under capital lease with a net carrying value of $23 million and $26 million at December 31, 2011 and 2010, respectively. The original cost basis of the buildings was $53 million and total accumulated amortization was $30 million and $27 million as of December 31, 2011 and 2010, respectively. Also includes unregulated property at ComEd and PECO.

(d) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $1,784 million and $1,592 million as of December 31, 2011 and 2010, 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 | 2011 | 2010 | 2009 |
|---|---|---|---|
| Electric—transmission and distribution | 2.59% | 2.53% | 2.43% |
| Electric—generation | 3.12% | 2.86% | 2.28% |
| Gas | 1.73% | 1.75% | 1.75% |
| Common—electric and gas | 8.05% | 7.25% | 6.41% |

### 6. Jointly Owned Electric Utility Plant

Exelon's, Generation's and PECO's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2011 and 2010 were as follows:

| | Nuclear generation | | | Fossil fuel generation | | | Transmission | | Other |
|---|---|---|---|---|---|---|---|---|---|
| | Quad Cities | Peach Bottom | Salem [(a)] | Keystone | Conemaugh | Wyman | PA [(b)] | DE/NJ [(c)] | Other [(d)] |
| Operator | Generation | Generation | PSEG Nuclear | GenOn | GenOn | FP&L | First Energy | PSEG | |
| Ownership interest | 75.00% | 50.00% | 42.59% | 20.99% | 20.72% | 5.89% | Various | 42.55% | 44.24% |
| **Exelon's share at December 31, 2011:** | | | | | | | | | |
| Plant | $ 822 | $ 650 | $ 420 | $ 366 | $ 271 | $ 3 | $ 5 | $ 66 | $ 1 |
| Accumulated depreciation | 156 | 285 | 103 | 137 | 154 | 3 | 3 | 33 | — |
| Construction work in progress | 37 | 111 | 61 | 5 | 15 | — | — | — | — |
| **Exelon's share at December 31, 2010:** | | | | | | | | | |
| Plant | $ 709 | $ 566 | $ 395 | $ 360 | $ 247 | $ 3 | $ 8 | $ 60 | $ 1 |
| Accumulated depreciation | 124 | 274 | 96 | 128 | 152 | 2 | 5 | 29 | — |
| Construction work in progress | 63 | 88 | 72 | 3 | 11 | — | — | — | — |

(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, 2011 and 2010.

(b) PECO owns a 22% share in 127 miles of 500 kV lines located in Pennsylvania; PECO also owns a 20.7% share of a 500 kV substation immediately outside of the Conemaugh fossil generating station which supplies power to the 500 kV lines noted above.
(c) PECO owns a 42.55% share in 131 miles of 500 kV lines located in Delaware and New Jersey as well as a 42.55% share in a 500kV substation immediately outside of the Salem nuclear generating station in New Jersey which supplies power to the 500kV lines noted above.
(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

Exelon's and ComEd's gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2011 and 2010 were as follows:

| | 2011 | | | 2010 | | |
|---|---|---|---|---|---|---|
| | Gross Amount [(a)] | Accumulated Impairment Losses | Carrying Amount | Gross Amount [(a)] | Accumulated Impairment Losses | Carrying Amount |
| Balance, January 1 | $4,608 | $1,983 | $2,625 | $4,608 | $1,983 | $2,625 |
| Impairment losses | — | — | — | — | — | — |
| Balance, December 31, | $4,608 | $1,983 | $2,625 | $4,608 | $1,983 | $2,625 |

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom merger net of amortization, resolution of tax matters and other non-impairment-related changes as allowed under previous authoritative guidance.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually, or more frequently if events or circumstances indicate that goodwill might be impaired. The impairment assessment is performed using a two-step, fair value based test. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

Exelon assesses goodwill impairment at its ComEd reporting unit. Accordingly, any goodwill impairment charge at ComEd will affect Exelon's consolidated results of operations. Under the effective authoritative guidance for fair value measurement, Exelon and ComEd estimate the fair value of the ComEd reporting unit using a weighted combination of a discounted cash flow analysis and a market multiples analysis. New guidance that does not have an impact on the Step 1 test will become effective for ComEd January 1, 2012. See Note 1—Significant Accounting Policies for additional information on the new guidance. The discounted cash flow analysis relies on a single scenario reflecting "base case" or "best estimate" projected cash flows for ComEd's business and includes an estimate of ComEd's terminal value based on these expected cash flows using the generally accepted Gordon Dividend Growth formula, which derives a valuation using an assumed perpetual annuity based on the entity's residual cash flows. The discount rate is based on the generally accepted Capital Asset Pricing Model and represents the weighted average cost of capital of comparable companies. The market multiples analysis utilizes multiples of business enterprise value to earnings, before interest, taxes, depreciation and amortization (EBITDA) of comparable companies in estimating fair value. Significant assumptions used in estimating the fair value include discount and growth rates, utility sector market performance and transactions, operating and capital expenditure requirements and the fair value of debt. Management performs a reconciliation of the sum of the estimated fair value of all Exelon reporting units to Exelon's enterprise value based on its trading price to corroborate the results of the discounted cash flow analysis and the market multiple analysis.

***2011 Annual Goodwill Impairment Assessment.*** The 2011 annual goodwill impairment assessment was performed as of November 1, 2011. 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. Operating and capital expenditure requirements used for the 2011 assessment included the impacts of EIMA discussed in Note 2—Regulatory Matters.

Although the fair value of the reporting unit currently exceeds its carrying value, deterioration in market related factors used in the impairment review, a fully successful IRS challenge to Exelon's and ComEd's like-kind exchange income tax position or adverse regulatory actions such as early termination of EIMA could potentially result in a future impairment loss of ComEd's goodwill, which could be material.

***Prior Goodwill Impairment Assessments.*** The 2010 and 2009 annual goodwill impairment assessments were performed as of November 1, 2010 and November 1, 2009, respectively. In each case, the first step of the annual impairment analysis, comparing the fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

**Other Intangible Assets**

Exelon's other intangible assets, included in deferred debits and other assets in their Consolidated Balance Sheets, consisted of the following as of December 31, 2011:

| | Gross | Accumulated Amortization | Net | Estimated amortization expense 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|
| Exelon Wind acquisition [a] | $224 | $ (13) | $211 | $ 13 | $14 | $14 | $14 | $14 |
| Antelope Valley acquisition [b] | 190 | — | 190 | — | 6 | 7 | 7 | 7 |
| Chicago settlement—1999 agreement [c] | 100 | (69) | 31 | 3 | 3 | 3 | 3 | 3 |
| Chicago settlement—2003 agreement [d] | 62 | (31) | 31 | 4 | 4 | 4 | 4 | 4 |
| Total intangible assets | $576 | $(113) | $463 | $ 20 | $27 | $28 | $28 | $28 |

(a) Refer to Note 3—Acquisition for additional information regarding Exelon Wind.

(b) Refer to Note 3—Acquisition for additional information regarding Antelope Valley.

(c) In March 1999, ComEd entered into a settlement agreement with the City of Chicago associated with ComEd's franchise agreement. Under the terms of the settlement, ComEd agreed to make payments to the City of Chicago each year from 1999 to 2002. The intangible asset recognized as a result of these payments is being amortized ratably over the remaining term of the franchise agreement, which ends in 2020.

(d) In February 2003, ComEd entered into separate agreements with the City of Chicago and with Midwest Generation, LLC (Midwest Generation). Under the terms of the settlement agreement with the City of Chicago, ComEd agreed to pay the City of Chicago a total of $60 million over a ten-year period, beginning in 2003. The intangible asset recognized as a result of the settlement agreement is being amortized ratably over the remaining term of the City of Chicago franchise agreement, which ends in 2020. As required by the settlement, ComEd also made a payment of $2 million to a third party on the City of Chicago's behalf. Under the terms of the agreement with Midwest Generation, ComEd received payments of $32 million from Midwest Generation to relieve Midwest Generation's obligation under the 1999 fossil sale agreement with ComEd to build the generation facility in the City of Chicago. The payments received by ComEd, which have been recorded in other long-term liabilities, are being recognized ratably (approximately $2 million annually) as an offset to amortization expense over the remaining term of the franchise agreement.

The following table summarizes the amortization expense related to intangible assets for each of the years ended December 31, 2011, 2010 and 2009:

| | |
|---|---|
| 2011 | $19 |
| 2010 | 8 |
| 2009 | 7 |

## *Acquired Intangible Assets*

Accounting guidance for business combinations requires that the acquirer must recognize separately identifiable intangible assets in the application of purchase accounting. The valuation of the acquired intangible assets discussed below were estimated by applying the income approach, which is based upon discounted projected future cash flows associated with the respective PPAs. Those measures are based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance.

***Antelope Valley.*** Upon completion of the development project, all of the output will be sold under a PPA with Pacific Gas & Electric. The excess of the contract price of the PPA over forecasted MPR-based market prices was recognized as an intangible asset at the acquisition date. Generation determined that the estimated acquisition-date fair value of the intangible asset was approximately $190 million, which was recorded in other deferred debits and other assets within Exelon's Consolidated Balance Sheets. While Generation expects to perform under the PPA once the construction of this project is complete, there is a risk of impairment if the project does not reach commercial operation.

Key assumptions used in the valuation of the intangible asset include forecasted MRP-based market prices and discount rate. The intangible asset will be amortized as revenue is earned over the 25 term of the underlying PPA. The amortization expense will be reflected as a decrease in operating revenue within Exelon's Consolidated Statements of Operations and Comprehensive Income.

***Exelon Wind.*** The output of the acquired wind turbines has been sold under PPA contracts. The excess of the contract price of the PPAs over market prices was recognized as intangible assets. Generation determined that the estimated acquisition-date fair value of the intangible assets was approximately $224 million, which was recorded in other deferred debits and other assets within Exelon's Consolidated Balance Sheets. Included in this amount is $21 million related to the PPAs for the projects that are in the advanced stage of development. While Generation expects to perform under the PPAs once the construction of these projects is complete, there is a risk of impairment if the projects do not reach commercial operation.

Key assumptions used in the valuation of the intangible assets include forecasted power prices and discount rate. The intangible assets will be amortized on a straight-line basis over the period in which the associated contract revenues are recognized. The amortization expense will be reflected as a decrease in operating revenue within Exelon's Consolidated Statements of Operations and Comprehensive Income. The weighted-average amortization period for these intangibles is approximately 18 years.

***Renewable Energy Credits and Alternative Energy Credits.***

Exelon's, Generation's and PECO's other intangible assets, included in other current assets and other deferred debits and other assets on the Consolidated Balance Sheets, include RECs and AECs. As of December 31, 2011 and 2010, PECO had current AECs of $14 million and $10 million, respectively, and noncurrent AECs of $16 million and $11 million, respectively. As of December 31, 2011 and 2010, the balances of RECs for Generation, which are considered noncurrent, were $6 million and $8 million, respectively. See Notes 2—Regulatory Matters and Note 18—Commitments and Contingencies for additional information on RECs and AECs.

## 8. Fair Value of Financial Assets and Liabilities

*Non-Derivative Financial Assets and Liabilities.* As of December 31, 2011 and 2010, Exelon's carrying amounts of cash and cash equivalents, accounts receivable, accounts payable, short term notes payable and accrued liabilities are representative of fair value because of the short-term nature of these instruments.

***Fair Value of Financial Liabilities Recorded at the Carrying Amount***

*Exelon*

The carrying amounts and fair values of Exelon's long-term debt, SNF obligation and preferred securities of subsidiary as of December 31, 2011 and 2010 were as follows:

| | 2011 | | 2010 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Long-term debt (including amounts due within one year) | $12,627 | $14,488 | $12,213 | $12,960 |
| Long-term debt to financing trusts | 390 | 358 | 390 | 350 |
| Spent nuclear fuel obligation | 1,019 | 886 | 1,018 | 876 |
| Preferred securities of subsidiary | 87 | 79 | 87 | 68 |

The fair value of long-term debt is determined using 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 and Generation's SNF obligation resulted from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations.

Exelon and Generation's obligation to the DOE accrues at the 13-week Treasury rate. When determining the fair value of the obligation, the future carrying amount of the SNF obligation in 2020 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The future compounded obligation amount is discounted back to present using the prevailing Treasury rate for a long-term obligation with an estimated maturity date of 2020 (after being adjusted for Generation's credit risk).

**Recurring Fair Value Measurements**

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1—quoted prices (unadjusted) in active markets for identical assets or liabilities that Exelon has 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, and money market funds.
- Level 2—inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. Financial assets and liabilities utilizing Level 2 inputs include fixed income securities, non-exchange-based derivatives, commingled and mutual investment funds priced at NAV per fund share and fair value hedges.
- Level 3—unobservable inputs, such as internally developed pricing models for the asset or liability due to little or no market activity for the asset or liability. Financial assets and liabilities utilizing Level 3 inputs include infrequently traded non-exchange-based derivatives and investments priced using an alternative pricing mechanism.

There were no significant transfers between Level 1 and Level 2 during the years ended December 31, 2011 and 2010. See Note 13—Retirement Benefits for further information regarding the fair value and related valuation techniques for pension and postretirement plan assets.

The following tables present assets and liabilities measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2011 and 2010:

| As of December 31, 2011 | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Assets** | | | | |
| Cash equivalents[a] | $ 861 | $ — | $— | $ 861 |
| Nuclear decommissioning trust fund investments | | | | |
| Cash equivalents | 504 | — | — | 504 |
| Equity | | | | |
| Equity securities | 1,275 | — | — | 1,275 |
| Commingled funds | — | 1,822 | — | 1,822 |
| Equity funds subtotal | 1,275 | 1,822 | — | 3,097 |
| Fixed income | | | | |
| Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies | 774 | 345 | — | 1,119 |
| Debt securities issued by states of the United States and political subdivisions of the states | — | 541 | — | 541 |
| Corporate debt securities | — | 779 | — | 779 |
| Federal agency mortgage-backed securities | — | 357 | — | 357 |
| Commercial mortgage-backed securities (non-agency) | — | 83 | — | 83 |
| Residential mortgage-backed securities (non-agency) | — | 5 | — | 5 |
| Mutual funds | — | 47 | — | 47 |
| Fixed income subtotal | 774 | 2,157 | — | 2,931 |
| Other debt obligations | — | 19 | 13 | 32 |
| Nuclear decommissioning trust fund investments subtotal [b] | 2,553 | 3,998 | 13 | 6,564 |
| Pledged assets for Zion decommissioning | | | | |
| Cash equivalents | — | — | — | — |
| Equity | | | | — |
| Equity securities | 35 | — | — | 35 |
| Commingled funds | — | 30 | — | 30 |
| Equity funds subtotal | 35 | 30 | — | 65 |
| Fixed income | | | | |
| Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies | 54 | 26 | — | 80 |
| Debt securities issued by states of the United States and political subdivisions of the states | — | 65 | — | 65 |
| Corporate debt securities | — | 311 | — | 311 |
| Federal agency mortgage-backed securities | — | 121 | — | 121 |
| Commercial mortgage-backed securities (non-agency) | — | 10 | — | 10 |
| Commingled funds | — | 20 | — | 20 |
| Fixed income subtotal | 54 | 553 | — | 607 |
| Direct lending funds | — | — | 37 | 37 |
| Other debt obligations | — | 16 | — | 16 |
| Pledged assets for Zion decommissioning subtotal [c] | 89 | 599 | 37 | 725 |

| As of December 31, 2011 | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Rabbi trust investments | | | | |
| Cash equivalents | 2 | — | — | 2 |
| Mutual funds [d] | — | 34 | — | 34 |
| Rabbi trust investments subtotal | 2 | 34 | — | 36 |
| Commodity mark-to-market derivative assets | | | | |
| Cash flow hedges | — | 857 | — | 857 |
| Other derivatives | — | 1,653 | 124 | 1,777 |
| Proprietary trading | — | 240 | 48 | 288 |
| Interest rate mark-to-market derivative assets | — | 15 | — | 15 |
| Effect of netting and allocation of collateral [e] | — | (1,827) | (28) | (1,855) |
| Mark-to-market assets [f] | — | 938 | 144 | 1,082 |
| **Total assets** | 3,505 | 5,569 | 194 | 9,268 |
| **Liabilities** | | | | |
| Commodity mark-to-market derivative liabilities | | | | |
| Cash flow hedges | — | (13) | — | (13) |
| Other derivatives | (1) | (1,137) | (119) | (1,257) |
| Proprietary trading | — | (236) | (28) | (264) |
| Interest rate mark-to-market derivative liabilities | — | (19) | — | (19) |
| Effect of netting and allocation of collateral [e] | — | 1,295 | 20 | 1,315 |
| Mark-to-market liabilities [f] | (1) | (110) | (127) | (238) |
| Deferred compensation | — | (73) | — | (73) |
| **Total liabilities** | (1) | (183) | (127) | (311) |
| **Total net assets** | $3,504 | $ 5,386 | $ 67 | $ 8,957 |

| As of December 31, 2010 | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Assets** | | | | |
| Cash equivalents [a] | $1,473 | $ — | $ — | $ 1,473 |
| Nuclear decommissioning trust fund investments | | | | |
| Cash equivalents | 45 | — | — | 45 |
| Equity | | | | |
| Equity securities | 1,513 | — | — | 1,513 |
| Commingled funds | — | 2,081 | — | 2,081 |
| Equity funds subtotal | 1,513 | 2,081 | — | 3,594 |
| Fixed income | | | | |
| Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies | 504 | 96 | — | 600 |
| Debt securities issued by states of the United States and political subdivisions of the states | — | 451 | — | 451 |
| Corporate debt securities | — | 619 | — | 619 |
| Federal agency mortgage-backed securities | — | 804 | — | 804 |
| Commercial mortgage-backed securities (non-agency) | — | 114 | — | 114 |
| Residential mortgage-backed securities (non-agency) | — | 14 | — | 14 |
| Commingled funds | — | 47 | — | 47 |
| Mutual funds | — | 40 | — | 40 |
| Fixed income subtotal | 504 | 2,185 | — | 2,689 |
| Other debt obligations | — | 48 | — | 48 |
| Nuclear decommissioning trust fund investments subtotal [b] | 2,062 | 4,314 | — | 6,376 |

| As of December 31, 2010 | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Pledged assets for Zion decommissioning | | | | |
| Equity | | | | |
| Equity securities | 84 | — | — | 84 |
| Commingled funds | — | 82 | — | 82 |
| Equity funds subtotal | 84 | 82 | — | 166 |
| Fixed income | | | | |
| Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies | 166 | 12 | — | 178 |
| Debt securities issued by states of the United States and political subdivisions of the states | — | 45 | — | 45 |
| Corporate debt securities | — | 263 | — | 263 |
| Federal agency mortgage-backed securities | — | 102 | — | 102 |
| Commercial mortgage-backed securities (non-agency) | — | 14 | — | 14 |
| Commingled funds | — | 50 | — | 50 |
| Fixed income subtotal | 166 | 486 | — | 652 |
| Other debt obligations | — | 2 | — | 2 |
| Pledged assets for Zion decommissioning subtotal (c) | 250 | 570 | — | 820 |
| Rabbi trust investments | | | | |
| Mutual funds (d) | — | 36 | — | 36 |
| Rabbi trust investments subtotal | — | 36 | — | 36 |
| Mark-to-market derivative assets | | | | |
| Cash flow hedges | — | 724 | 12 | 736 |
| Other derivatives | 2 | 1,709 | 57 | 1,768 |
| Proprietary trading | — | 235 | 46 | 281 |
| Effect of netting and allocation of collateral (e) | (3) | (1,848) | (38) | (1,889) |
| Mark-to-market assets (f) | (1) | 820 | 77 | 896 |
| **Total assets** | 3,784 | 5,740 | 77 | 9,601 |
| **Liabilities** | | | | |
| Mark-to-market derivative liabilities | | | | |
| Cash flow hedges | — | (45) | — | (45) |
| Other derivatives | (2) | (667) | (29) | (698) |
| Proprietary trading | — | (233) | (21) | (254) |
| Effect of netting and allocation of collateral (e) | 1 | 914 | 23 | 938 |
| Mark-to-market liabilities (f) | (1) | (31) | (27) | (59) |
| Deferred compensation | — | (76) | — | (76) |
| **Total liabilities** | (1) | (107) | (27) | (135) |
| **Total net assets** | $3,783 | $ 5,633 | $ 50 | $ 9,466 |

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.

(b) Excludes net (liabilities) assets of $(57) million and $32 million at December 31, 2011 and 2010, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables and payables related to pending securities purchases.

(c) Excludes net assets of $9 million and $4 million at December 31, 2011 and 2010. These items consist of receivables related to pending securities sales, interest and dividend receivables and payables related to pending securities purchases.

(d) Excludes $25 million of the cash surrender value of life insurance investments at December 31, 2011 and 2010.

(e) Includes collateral postings received from counterparties. Collateral received from counterparties, net of collateral paid to counterparties, totaled $532 million and $8 million allocated to Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2011. Collateral received from counterparties, net of collateral paid to counterparties, totaled $2 million, $934 million and $15 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2010.

(f) The Level 3 balance does not include current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $503 million and $191 million at December 31, 2011 and $450 million and $525 million at December 31, 2010, respectively, related to the fair value of Generation's financial swap contract with ComEd; and current assets of $5 million at December 31, 2010, related to the fair value of Generation's block contracts with PECO, which eliminate upon consolidation in Exelon's Consolidated Financial Statements. Generation's block contracts with PECO ended December 31, 2011.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2011 and 2010:

| For the Year Ended December 31, 2011 | Nuclear Decommissioning Trust Fund Investment | Pledged Assets for Zion Station Decommissioning | Mark-to-Market Derivatives | Total |
|---|---|---|---|---|
| Balance as of January 1, 2011 | $— | $ — | $ 50 | $ 50 |
| Total realized / unrealized gains (losses) | | | | |
| Included in income | 1 | — | 99[(a)] | 100 |
| Included in other comprehensive income | — | — | (25)[(b)] | (25) |
| Included in regulatory liabilities | 2 | — | (106) | (104) |
| Change in collateral | — | — | 6 | 6 |
| Purchases, sales, issuances and settlements | | | | |
| Purchases | 10 | 60 | 10 | 80 |
| Sales | — | (23) | — | (23) |
| Transfers out of Level 3 | — | — | (17) | (17) |
| Balance as of December 31, 2011 | $ 13 | $ 37 | $ 17 | $ 67 |
| The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the year ended December 31, 2011 | $ 1 | $ — | $ 131 | $ 132 |

(a) Includes the reclassification of $32 million of realized losses due to settlements of derivative contracts recorded in results of operations for the year ended December 31, 2011.

(b) Excludes $170 million of increases in fair value and $451 million of realized losses reclassified from OCI due to settlements of associated with Generation's financial swap contract with ComEd for the year ended December 31, 2011 and $5 million of decreases in fair value due to settlement of Generation's block contracts with PECO for the year ended December 31, 2011. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

| For the Year Ended December 31, 2010 | Servicing Liability | Nuclear Decommissioning Trust Fund Investments | Mark-to-Market Derivatives | Total |
|---|---|---|---|---|
| Balance as of January 1, 2010 | $ (2) | $— | $(44) | $(46) |
| Total realized / unrealized gains | | | | |
| Included in income | 2[(c)] | — | 46[(a)] | 48 |
| Included in other comprehensive income | — | — | 16[(b)] | 16 |
| Included in regulatory assets/liabilities | — | — | 2 | 2 |
| Change in collateral | — | — | (10) | (10) |
| Purchases, sales, issuances and settlements | | | | |
| Purchases | — | 13 | 15 | 28 |
| Sales | — | (1) | — | (1) |
| Transfers out of Level 3 | — | (12) | 25 | 13 |
| Balance as of December 31, 2010 | $— | $— | $ 50 | $ 50 |
| The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the year ended December 31, 2010 | $— | $— | $ 54 | $ 54 |

(a) Includes the reclassification of $8 million of realized losses due to settlements of derivative contracts recorded in results of operations.

(b) Excludes increases in fair value of $375 million and realized losses reclassified from OCI due to settlements of $371 million associated with Generation's financial swap contract with ComEd for the year ended December 31, 2010. The PECO block contracts were designated as normal sales as of May 31, 2010. As such, there were no effective changes in the fair value of the block contracts with PECO after that point, as the mark-to-market balances previously recorded will be amortized over the term of the contracts. The increase in fair value was $3 million through May 31, 2010. Generation's block contracts with PECO ended December 31, 2011. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

(c) The servicing liability related to PECO's accounts receivable agreement was released in accordance with new guidance on accounting for transfers of financial assets that was adopted on January 1, 2010. See Note 10—Debt and Credit Agreements for additional information.

The following table presents total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2011 and 2010:

| | Operating Revenue | Purchased Power | Fuel | Other, net (a) |
|---|---|---|---|---|
| Total gains (losses) included in income for the year ended December 31, 2011 | $108 | $— | $ (9) | $ 1 |
| Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2011 | $137 | $— | $ (6) | $ 1 |

| | Operating Revenue | Purchased Power | Fuel | Other, net |
|---|---|---|---|---|
| Total gains included in income for the year ended December 31, 2010 | $ 3 | $ 7 | $36 | $— |
| Change in the unrealized gains relating to assets and liabilities held for the year ended December 31, 2010 | $ 22 | $ 4 | $28 | $— |

(a) Other, net activity consists of realized and unrealized gains included in income for the NDT funds held by Generation.

***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.* Exelon's cash equivalents include investments with maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

*Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning.* The trust fund investments have been established to satisfy Exelon's and Generation's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds. Generation's investment policies place limitations on the types and investment grade ratings of the securities that may be held by the trusts. These policies limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments. 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.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2.

Equity and fixed income commingled funds and fixed income mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair values of fixed income commingled and mutual funds held within the trust funds, which generally hold short-term fixed income securities and are not subject to restrictions regarding the purchase or sale of shares, are derived from observable prices. The objectives of the remaining equity commingled funds in which

Exelon and Generation invest primarily seek to track the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. In general, equity commingled funds are redeemable on the 15th of the month and the last business day of the month; however, the fund manager may designate any day as a valuation date for the purpose of purchasing or redeeming units. Commingled and mutual funds are categorized in Level 2 because the fair value of the funds are based on NAVs per fund share (the unit of account), primarily derived from the quoted prices in active markets on the underlying equity securities. See Note 12—Nuclear Decommissioning for further discussion on the NDT fund investments.

Direct lending funds are investments in managed funds which invest in private companies for long-term capital appreciation. The fair value of these securities is determined using either an enterprise value model or a bond valuation model. Investments in direct lending funds are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models.

*Rabbi Trust Investments.* The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The investments in the Rabbi trusts are included in investments in Exelon's Consolidated Balance Sheets. The investments are in fixed-income commingled funds and mutual funds, including short-term investment funds. These funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For fixed-income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Fixed-income commingled funds which are publicly quoted, such as money market funds, have been categorized as Level 1 given the clear observability of the prices.

*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 Exelon believes provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of non-exchange-based derivative contracts is valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For non-exchange-based derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. Exelon's non-exchange-based derivatives are predominately at liquid trading points. For non-exchange-based derivatives that trade in less liquid markets with limited pricing information, such as the financial swap contract between Generation and ComEd, model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon considers credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements. Transfers in and out of levels are recognized as of the beginning of the month the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 generally do not occur. Transfers into and out of Level 2 and Level 3, respectively, generally occur when the contract tenure becomes more observable.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, Exelon may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. 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.* Exelon's deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. Exelon includes such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of Exelon's deferred compensation obligations is based on the market value of the participants' notional investment accounts. The notional investments are comprised primarily of mutual funds, which are based on observable market prices. However, since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized in Level 2 in the fair value hierarchy.

*Servicing Liability.* PECO is party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in customer accounts receivables designated under the agreement in exchange for proceeds of $225 million, which PECO accounted for as a sale under previous guidance on accounting for transfers of financial assets. A servicing liability was recorded for the agreement in accordance with the applicable authoritative guidance for servicing of financial assets. The servicing liability was included in other current liabilities in Exelon's Consolidated Balance Sheets. The fair value of the liability was determined using internal estimates based on provisions in the agreement, which were categorized as Level 3 inputs in the fair value hierarchy. The servicing liability was released in accordance with new guidance on accounting for transfers of financial assets that was adopted on January 1, 2010. See Note 10—Debt and Credit Agreements for additional information.

## 9. Derivative Financial Instruments

Exelon is exposed to certain risks related to ongoing business operations. The primary risks managed by using derivative financial instruments are commodity price risk and interest rate risk. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon is exposed to market price fluctuations in the prices of electricity, fossil fuels and other commodities. Exelon employs established policies and procedures to manage their risks associated with market fluctuations by entering into physical contracts as well as financial derivative contracts including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. Exelon believes these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices. Exposure to interest rate risk exists as a result of the issuance of variable and fixed-rate debt, commercial paper and lines of credit.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value. Under these provisions, economic hedges are recognized on the balance sheet at their fair value unless they qualify for the normal purchases and normal sales exception. Exelon has applied the normal purchases and normal sales scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. For economic hedges that qualify and are designated as cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in value of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. For economic hedges that do not qualify or are not designated as cash flow hedges, changes in the fair value of the derivative are recognized in earnings each period and are classified as other derivatives in the following tables. Non-derivative contracts for access to additional generation and for sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 18—Commitments and Contingencies. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities.

### *Commodity Price Risk*

*Economic Hedging.* Exelon is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. Within Exelon, Generation has the most exposure to commodity price risk. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases, and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management's policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments, which include financial transmission rights, whose changes in fair value are recognized in earnings each period, and auction revenue rights.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions that have not been hedged. Generation hedges commodity risk on a ratable basis over three-year periods. As of December 31, 2011, the percentage of expected generation hedged was 88%-91%, 61%-64%, and 32%-35% for 2012, 2013 and 2014, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include cash flow hedges, other derivatives and certain non-derivative contracts, including sales to ComEd and PECO to serve their retail load.

ComEd has locked in a fixed price for a significant portion of its commodity price risk through the five-year financial swap contract with Generation that expires on May 31, 2013, which is discussed in more detail below. In addition, the contracts that Generation has entered into with ComEd and that ComEd has entered into with Generation and other suppliers as part of the ComEd power procurement process, which is further discussed in Note 2—Regulatory Matters, qualify for the normal purchases and normal sales scope exception. Based on the Illinois Settlement Legislation and ICC-approved procurement methodologies permitting ComEd to recover its electricity procurement costs from retail customers with no mark-up, ComEd's price risk related to power procurement is limited.

In order to fulfill a requirement of the Illinois Settlement Legislation, Generation and ComEd entered into a five-year financial swap contract effective August 28, 2007. The financial swap is designed to hedge spot market purchases, which, along with ComEd's remaining energy procurement contracts, meet its load service requirements. The remaining swap contract volume is 3,000 MWs through May 2013. The terms of the financial swap contract require Generation to pay the around-the-clock market price for a portion of ComEd's electricity supply requirement, while ComEd pays a fixed price. The contract is to be settled net, for the difference between the fixed and market pricing, and the financial terms only cover energy costs and do not cover capacity or ancillary services. The financial swap contract is a derivative financial instrument that has been designated by Generation as a cash flow hedge. Consequently, Generation records the fair value of the swap on its balance sheet and records changes in fair value to OCI. ComEd has not elected hedge accounting for this derivative financial instrument. Since the financial swap contract was deemed prudent by the Illinois Settlement Legislation, ComEd receives full cost recovery for the contract in rates, and therefore, the change in fair value each period is recorded as a regulatory asset or liability on ComEd's Consolidated Balance Sheets in Exelon's 2011 Form 10-K. See Note 2—Regulatory Matters for additional information regarding the Illinois Settlement Legislation. In Exelon's consolidated financial statements, all financial statement effects of the financial swap recorded by Generation and ComEd are eliminated.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts begins in June 2012. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Program, which is further discussed in Note 2—Regulatory Matters. Based on Pennsylvania legislation and the DSP Program permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts and block contracts. PECO's full requirements contracts and block contracts, which are considered derivatives, qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. For block contracts designated as normal purchases after inception, the mark-to-market balances previously recorded on PECO's Consolidated Balance Sheets in Exelon's 2011 Form 10-K were amortized over the terms of the contracts, which ended on December 31, 2011.

PECO's natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO's reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO's natural gas supply and asset management agreements that are derivatives either qualify for the normal purchases and normal sales scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2011 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2011 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program covers 22% to 29% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

*Proprietary Trading.* Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into purely to profit from market price changes as opposed to hedging an exposure and is subject to limits established by Exelon's RMC. The proprietary trading activities, which included physical volumes of 5,742 GWh, 3,625 GWh and 7,578 GWh for years ended December 31, 2011, 2010 and 2009, respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's revenue from energy marketing activities. Neither ComEd nor PECO enter into derivatives for proprietary trading purposes.

### *Interest Rate Risk*

Exelon uses a combination of fixed-rate and variable-rate debt to manage interest rate exposure. Exelon may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, Exelon may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. A hypothetical 10% increase in the interest rates associated with variable-rate debt would result in less than a $1 million decrease in Exelon's, Generation's, and ComEd's pre-tax income for the year ended December 31, 2011.

*Fair Value Hedges.* For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows:

| | Gain (Loss) on Swaps December 31, | | | Gain (Loss) on Borrowings December 31, | | |
|---|---|---|---|---|---|---|
| **Income Statement Classification** | **2011** | **2010** | **2009** | **2011** | **2010** | **2009** |
| Interest expense | $1 | $4 | $(7) | $(1) | $(4) | $7 |

At December 31, 2011 and 2010, Exelon had $100 million of notional amounts of fair value hedges outstanding related to interest rate swaps, with fair value assets of $15 million and $14 million, respectively. During the years ended December 31, 2011 and 2010, there was no impact on the results of operations as a result of ineffectiveness from fair value hedges.

*Cash Flow Hedges.* In connection with the DOE guaranteed loan for the Antelope Valley acquisition, as discussed in Note 10–Debt and Credit Agreements, Generation entered into a floating-to-fixed interest rate swap with a notional amount of $485 million, which hedges approximately 75% of Generation's future interest rate exposure associated with the financing. The swap was designated as a cash flow hedge, as Generation has determined that the DOE loan remains probable to occur. As such, the effective portion of the hedge will be recorded in other comprehensive income within Generation's Consolidated Balance Sheets in Exelon's 2011 Form 10-K, with any ineffectiveness recorded in Generation's Consolidated Statements of Operations and Comprehensive Income in Exelon's 2011 Form 10-K. Net gains (or losses) from settlement of the hedges, to the extent effective, will be amortized as an adjustment to the interest expense over the term of the DOE guaranteed loan.

As Generation draws down on the loan, a portion of the cash flow hedge will be de-designated and the related gains or losses will be reflected in earnings through the remaining term of the hedge. In order to mitigate this earnings impact, a series of offsetting hedge transactions will be executed as Generation draws on the loan. At December 31, 2011, Generation had a $19 million mark-to-market non-current derivative liability relating to the interest rate swap in connection with the loan agreement to fund Antelope Valley as discussed above.

On September 30, 2010, Generation issued and sold $350 million of senior notes due October 1, 2041. In connection with this debt issuance, Generation entered into treasury rate locks in the aggregate notional amount of $240 million. The treasury rate locks were settled on September 27, 2010. Treasury rate locks were derivative instruments used to lock in the interest rate prior to the issuance of debt. As a result of a decrease in interest rates during the period between the inception and settlement of the treasury rate locks, Generation recorded a pre-tax loss of approximately $4 million. The loss was recorded to other comprehensive income within Generation's Consolidated Balance Sheets in Exelon's 2011 Form 10-K and is being amortized as an increase to interest expense over the life of the related debt as interest payments are made on the debt.

In connection with its August 2, 2010 issuance of First Mortgage Bonds, ComEd entered into treasury rate locks in the aggregate notional amount of $350 million. The treasury rate locks were settled on July 27, 2010. As interest rates decreased since the inception of the treasury rate locks, ComEd recorded a pre-tax loss of approximately $4 million. Under the authoritative accounting guidance for regulated operations, the loss was recorded as a regulatory asset within ComEd's Consolidated Balance Sheets in Exelon's 2011 Form 10-K at settlement and is being amortized as an increase to interest expense over the life of the related debt as interest payments are made on the debt.

***Fair Value Measurement***

Fair value accounting guidance requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to master netting agreements and qualify for net presentation in the Consolidated Balance Sheets. In the table below, Generation's commodity cash flow hedges, other derivatives and proprietary trading derivatives are shown gross and the impact of the netting of fair value balances with the same counterparty, as well as netting of collateral, is aggregated in the collateral and netting column. Excluded from the tables below are economic hedges that qualify for the normal purchases and normal sales scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2011:

| | Generation | | | | | ComEd | PECO | Other | | Exelon |
|---|---|---|---|---|---|---|---|---|---|---|
| Derivatives | Cash Flow Hedges [a] | Other Derivatives | Proprietary Trading | Collateral and Netting [b] | Subtotal [c] | Other Derivatives [a][d] | Other Derivatives | Other Derivatives | Intercompany Eliminations [a] | Total Derivatives |
| Mark-to-market derivative assets (current assets) | $ 438 | $ 1,195 | $ 217 | $(1,418) | $ 432 | $ — | $— | $— | $ — | $ 432 |
| Mark-to-market derivative assets with affiliate (current assets) | 503 | — | — | — | 503 | — | — | — | (503) | — |
| Mark-to-market derivative assets (noncurrent assets) | 419 | 582 | 71 | (437) | 635 | — | — | 15 | — | 650 |
| Mark-to-market derivative assets with affiliate (noncurrent assets) | 191 | — | — | — | 191 | — | — | — | (191) | — |
| Total mark-to-market derivative assets | $1,551 | $ 1,777 | $ 288 | $(1,855) | $1,761 | $ — | $— | $ 15 | $(694) | $1,082 |
| Mark-to-market derivative liabilities (current liabilities) | $ (9) | $ (965) | $(194) | $ 1,065 | $ (103) | $ (9) | — | $— | $ — | $ (112) |
| Mark-to-market derivative liabilities with affiliate (current liabilities) | — | — | — | — | — | (503) | — | — | 503 | — |
| Mark-to-market derivative liabilities (noncurrent liabilities) | (4) | (186) | (70) | 250 | (10) | (97) | — | — | — | (107) |
| Mark-to-market derivative liabilities with affiliate (noncurrent liabilities) | — | — | — | — | — | (191) | — | — | 191 | — |
| Total mark-to-market derivative liabilities | $ (13) | $(1,151) | $(264) | $ 1,315 | $ (113) | $(800) | $— | $— | $ 694 | $ (219) |
| Total mark-to-market derivative net assets (liabilities) | $1,538 | $ 626 | $ 24 | $ (540) | $1,648 | $(800) | $— | $ 15 | $ — | $ 863 |

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $503 million and $191 million, respectively, related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above. For Generation, excludes $19 million noncurrent liability relating to an interest rate swap in connection with a loan agreement to fund Antelope Valley as discussed above.

(b) Represents the netting of fair value balances with the same counterparty and the application of collateral.

(c) Current and noncurrent assets are shown net of collateral of $338 million and $187 million, respectively, and current and noncurrent liabilities are shown inclusive of collateral of $15 million and $0 million, respectively. The total cash collateral received net of cash collateral posted and offset against mark-to-market assets and liabilities was $540 million at December 31, 2011.

(d) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2010:

| | Generation | | | | | ComEd | PECO | Other | | Exelon |
|---|---|---|---|---|---|---|---|---|---|---|
| Derivatives | Cash Flow Hedges [(a)] | Other Derivatives | Proprietary Trading | Collateral and Netting [(b)] | Subtotal [(c)] | Other Derivatives [(a)(e)] | Other Derivatives [(d)] | Other Derivatives | Intercompany Eliminations [(a)(d)] | Total Derivatives |
| Mark-to-market derivative assets (current assets) | $ 532 | $1,203 | $ 225 | $(1,473) | $ 487 | $ — | $— | $— | $ — | $487 |
| Mark-to-market derivative assets with affiliate (current assets) | 455 | — | — | — | 455 | — | — | — | (455) | — |
| Mark-to-market derivative assets (noncurrent assets) | 204 | 547 | 56 | (416) | 391 | 4 | — | 14 | — | 409 |
| Mark-to-market derivative assets with affiliate (noncurrent assets) | 525 | — | — | — | 525 | — | — | — | (525) | — |
| Total mark-to-market derivative assets | $1,716 | $1,750 | $ 281 | $(1,889) | $1,858 | $ 4 | $— | $ 14 | $(980) | $896 |
| Mark-to-market derivative liabilities (current liabilities) | $ (21) | $ (551) | $(200) | $ 738 | $ (34) | $ — | $ (4) | $— | $ — | $ (38) |
| Mark-to-market derivative liabilities with affiliate (current liabilities) | — | — | — | — | — | (450) | (5) | — | 455 | — |
| Mark-to-market derivative liabilities (noncurrent liabilities) | (24) | (143) | (54) | 200 | (21) | — | — | — | — | (21) |
| Mark-to-market derivative liabilities with affiliate (noncurrent liabilities) | — | — | — | — | — | (525) | — | — | 525 | — |
| Total mark-to-market derivative liabilities | $ (45) | $ (694) | $(254) | $ 938 | $ (55) | $(975) | $ (9) | $— | $ 980 | $ (59) |
| Total mark-to-market derivative net assets (liabilities) | $1,671 | $1,056 | $ 27 | $ (951) | $1,803 | $(971) | $ (9) | $ 14 | $ — | $837 |

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $450 million and $525 million, respectively, related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above.

(b) Represents the netting of fair value balances with the same counterparty and the application of collateral.

(c) Current and noncurrent assets are shown net of collateral of $725 million and $199 million, respectively, and current and noncurrent liabilities are shown inclusive of collateral of $10 million and $17 million, respectively. The total cash collateral received net of cash collateral posted and offset against mark-to-market assets and liabilities was $951 million at December 31, 2010.

(d) Includes current assets for Generation and current liabilities for PECO of $5 million related to the fair value of PECO's block contracts with Generation. There were no netting adjustments or collateral received as of December 31, 2010. The PECO block contracts were designated as normal purchases in May 2010. As such, no additional changes in the fair value of PECO's block contracts were recorded and the mark-to-market balances previously recorded were amortized over the terms of the contracts, which ended December 31, 2011.

(e) Includes noncurrent assets related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

*Cash Flow Hedges.* Economic hedges that qualify as cash flow hedges primarily consist of forward power sales and power swaps on base load generation. At December 31, 2011, Generation had net unrealized pre-tax gains on effective cash flow hedges of $1,529 million being deferred within accumulated OCI, including $694 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, 2011, approximately $925 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 $503 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, including the ComEd financial swap contract, will occur during 2012 through 2014.

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 when it is no longer probable that the forecasted transaction will occur. For the years ended December 31, 2011 and 2010, amounts reclassified into earnings as a result of the discontinuance of cash flow hedges were immaterial.

The table below provides the activity of accumulated OCI related to cash flow hedges for the years ended December 31, 2011 and 2010, containing information about the changes in the fair value of cash flow hedges and the reclassification from accumulated OCI into results of operations. The amounts reclassified from accumulated OCI, when combined with the impacts of the actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

| | | Total Cash Flow Hedge OCI Activity, Net of Income Tax | |
|---|---|---|---|
| | | Generation | Exelon |
| | Income Statement Location | Energy Related Hedges | Total Cash Flow Hedges |
| Accumulated OCI derivative gain at January 1, 2010 | | $1,152(a)(d) | $ 551 |
| Effective portion of changes in fair value | | 541(b) | 304(e) |
| Reclassifications from accumulated OCI to net income | Operating Revenues | (681)(c) | (454)(f) |
| Ineffective portion recognized in income | Purchased Power | (1) | (1) |
| Accumulated OCI derivative gain at December 31, 2010 | | 1,011(a)(d) | 400 |
| Effective portion of changes in fair value | | 504(b) | 402(e) |
| Reclassifications from accumulated OCI to net income | Operating Revenues | (585)(c) | (309) |
| Ineffective portion recognized in income | Operating Revenues | (5) | (5) |
| Accumulated OCI derivative gain at December 31, 2011 | | $ 925(a)(d) | $ 488 |

(a) Includes $420 million, $589 million and $585 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd for the years ended December 31, 2011, 2010 and 2009, respectively, and $3 million of gains, net of taxes, related to the fair value of the block contracts with PECO for the year ended December 31, 2010.

(b) Includes $104 million and $228 million of gains, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd for the years ended December 31, 2011 and 2010, respectively, and $2 million of gains, net of taxes, of the effective portion of changes in fair value of the block contracts with PECO for the year ended December 31, 2010. The PECO block contracts were designated as normal sales as of May 31, 2010. As such, there were no effective changes in fair value of the block contracts with PECO in 2011 or for the remainder of 2010 as the mark-to-market balances previously recorded were amortized over the terms of the contracts.

(c) Includes $273 million and $224 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the years ended December 31, 2011 and 2010, respectively, and $3 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to settlements of the block contracts with PECO for the year ended December 31, 2011.

(d) Excludes $10 million of losses and $2 million of gains, net of taxes, related to interest rate swaps and treasury rate locks for the years ended December 31, 2011 and 2010, respectively. Excludes $5 million of gains, net of taxes, related to interest rate swaps for the year ended December 31, 2009. See Note 10—Debt and Credit Agreements for further information.

(e) Includes $12 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks at Generation for the year ended December 31, 2011. Includes $6 million of losses, net of taxes, related to the effective portion of changes in fair value of treasury rate locks at Generation and ComEd for the year ended December 31, 2010.

(f) Reflects the reclassifications of $4 million to regulatory assets and $1 million to deferred income tax liabilities within Exelon's Consolidated Balance Sheets associated with settled treasury rate locks at ComEd.

During the years ended December 31, 2011, 2010 and 2009, Generation's cash flow hedge activity impact to pre-tax earnings, based on the reclassification adjustment from accumulated OCI to earnings, was a pre-tax gain of $968 million, $1,125 million and $1,559 million, respectively. Given that the cash flow hedges primarily consist of forward power sales and power swaps and do not include gas options or sales, the ineffectiveness of Generation's cash flow hedges is primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units. This price difference is actively managed through other instruments, which include financial transmission rights, whose changes in fair value are recognized in earnings each period, and auction revenue rights. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices, were increases of $9 million and $1 million, and a decrease of $15 million for the years ended December 31, 2011, 2010 and 2009, respectively, none of which was related to Generation's financial swap contract with ComEd or Generation's block contracts with PECO. Cash flow hedge ineffectiveness resulted in an decrease of $10 million and $1 million related to accumulated OCI on the balance sheet in order to reflect the effective portion of derivative gains or losses at December 31, 2011 and 2010, respectively.

Exelon's energy related cash flow hedge activity impact to pre-tax earnings, based on the reclassification adjustment from accumulated OCI to earnings, was a pre-tax gain of $512 million, $754 million and $1,292 million for the years ended December 31, 2011, 2010 and 2009, respectively. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices, were increases of $9 million, $1 million, and a decrease of $15 million for the years ended December 31, 2011, 2010 and 2009, respectively. Cash flow hedge ineffectiveness resulted in an decrease of $10 million and $1 million to accumulated OCI on the balance sheet in order to reflect the effective portion of derivative gains or losses at December 31, 2011 and 2010, respectively.

*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, 2011, 2010 and 2009, the following net pre-tax mark-to-market gains (losses) of certain sale and purchase contracts were reported in operating revenues and fuel and purchased power expense at Exelon in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

| For the Year Ended December 31, 2011 | Operating Revenues | Purchased Power | Fuel | Total |
|---|---|---|---|---|
| Change in fair value | $ 87 | $ 17 | $ 114 | $ 218 |
| Reclassification to realized at settlement | (296) | (31) | (188) | (515) |
| Net mark-to-market gains (losses) [(a)] | $(209) | $ (14) | $ (74) | $(297) |

| For the Year Ended December 31, 2010 | Operating Revenues | Purchased Power | Fuel | Total |
|---|---|---|---|---|
| Change in fair value | $ — | $ 288 | $ 101 | $ 389 |
| Reclassification to realized at settlement | — | (292) | (12) | (304) |
| Net mark-to-market gains (losses) | $ — | $ (4) | $ 89 | $ 85 |

| For the Year Ended December 31, 2009 | Operating Revenues | Purchased Power | Fuel | Total |
|---|---|---|---|---|
| Change in fair value | $ — | $ 206 | $ (72) | $ 134 |
| Reclassification to realized at settlement | — | (97) | 159 | 62 |
| Net mark-to-market gains | $ — | $ 109 | $ 87 | $ 196 |

(a) Exelon has historically presented mark-to-market gains and losses within purchased power expense for all non-trading, power-related derivatives that were not accounted for as cash flow hedges. In 2011, Exelon classified the mark-to-market gains and losses for contracts, where the underlying hedged transaction was an expected sale, to operating revenues. In prior years, this treatment was not material to reported operating revenues and purchased power expense. As a result, prior year amounts have not been reclassified.

*Proprietary Trading Activities.* For the years ended December 31, 2011, 2010 and 2009, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity on derivative instruments entered into for proprietary trading purposes. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

| | Location on Income Statement | For the Years Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|---|
| Change in fair value | Operating Revenues | $ 23 | $ 26 | $ 3 |
| Reclassification to realized at settlement | Operating Revenues | (26) | (24) | (86) |
| Net mark-to-market gains (losses) | Operating Revenues | $ (3) | $ 2 | $(83) |

***Credit Risk***

Exelon would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase and normal sales, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2011. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the maturity of a company's credit risk by credit rating of the counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs, NYMEX and ICE commodity exchanges, further discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd and PECO of $70 million and $39 million, respectively. See Note 21—Related Party Transactions for further information.

| Rating as of December 31, 2011 | 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 | $1,581 | $351 | $1,230 | 1 | $179 |
| Non-investment grade | 5 | 2 | 3 | — | — |
| No external ratings | | | | | |
| Internally rated—investment grade | 63 | 14 | 49 | — | — |
| Internally rated—non-investment grade | 1 | — | 1 | — | — |
| Total | $1,650 | $367 | $1,283 | 1 | $179 |

| Net Credit Exposure by Type of Counterparty | December 31, 2011 |
|---|---|
| Financial Institutions | $ 391 |
| Investor-owned utilities marketers and power producers | 552 |
| Energy cooperatives and municipalities | 282 |
| Other | 58 |
| Total | $1,283 |

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of December 31, 2011, ComEd's credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 2— Regulatory Matters for further information.

PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2011, PECO had no net credit exposure to suppliers.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 2—Regulatory Matters for further information.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain cash collateral from suppliers under its natural gas supply and asset management agreements; however, the natural gas asset managers have provided $14 million in parental guarantees related to these agreements. As of December 31, 2011, PECO had credit exposure of $11 million under its natural gas supply and asset management agreements with investment grade suppliers.

***Collateral and Contingent-Related Features***

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuels and emissions allowances. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. Generation also enters into commodity transactions on NYMEX and ICE. The NYMEX and ICE clearing houses act as the counterparty to each trade. Transactions on NYMEX and ICE must adhere to comprehensive collateral and margining requirements.

Generation's interest rate swap contains provisions that, in the event of a merger, require that Exelon's debt maintain an investment grade credit rating from Moody's or S&P. If Exelon's debt were to fall below investment grade, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on NYMEX and ICE that are fully collateralized) was $1,014 million and $742 million as of December 31, 2011 and 2010, respectively. As of December 31, 2011 and 2010, Generation had the contractual right of offset of $928 million and $717 million, respectively, related to derivative instruments that are assets with the same counterparty under master netting agreements, resulting in a net liability position of $86 million and $25 million, respectively. If Generation had been downgraded to the investment grade rating of BBB- and Baa3, or lost its investment grade credit rating, it would have had additional collateral obligations of approximately $307 million or $1,612 million, respectively, as of December 31, 2011 and approximately $57 million or $944 million, respectively, as of December 31, 2010 related to its financial instruments, including derivatives, non-derivatives, normal purchase normal and sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements and the application of collateral. See Note 18—Commitments and Contingencies for information regarding the letters of credit supporting the cash collateral.

Generation entered into SFCs with certain utilities, including PECO, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of the financial swap contract between Generation and ComEd, if a party is downgraded below investment grade by Moody's or S&P, collateral postings would be required by that party depending on how market prices compare to the benchmark price levels. Under the terms of the financial swap contract, collateral postings will never exceed $200 million from either ComEd or Generation. Under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of December 31, 2011, ComEd held both cash and letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts. These amounts were not material. Beginning in June 2010, under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, beginning in December 2010, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of December 31, 2011, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 2—Regulatory Matters for further information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2011, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2011, PECO could have been required to post approximately $54 million of collateral to its counterparties.

PECO's supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

Exelon's interest rate swaps contain provisions that, in the event of a merger, require that Exelon's debt maintain an investment grade credit rating from Moody's or S&P. If Exelon's debt were to fall below investment grade, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of December 31, 2011, Exelon's interest rate swap was in an asset position, with a fair value of $15 million.

***Accounting for the Offsetting of Amounts Related to Certain Contracts***

As of December 31, 2011 and 2010, $2 million and $1 million, respectively, of cash collateral received was not offset against net derivative positions, because it was not associated with energy-related derivatives.

**10. Debt and Credit Agreements**

***Short-Term Borrowings***

Exelon and ComEd meet their 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.

Exelon, Generation, ComEd and PECO had the following amounts of commercial paper borrowings at December 31, 2011 and 2010:

| Commercial Paper Issuer | Maximum Program Size at December 31, 2011 (a) | Maximum Program Size at December 31, 2010 (a) | Outstanding Commercial Paper at December 31, 2011 | Outstanding Commercial Paper at December 31, 2010 | Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31, 2011 | Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31, 2010 |
|---|---|---|---|---|---|---|
| Exelon Corporate | $ 500 | $ 957 | $161 | $— | 0.42% | — |
| Generation | 5,600 | 4,834 | — | — | 0.48% | — |
| ComEd | 1,000 | 1,000 | — | — | 0.71% | 0.74% |
| PECO | 600 | 574 | — | — | — | — |
| **Total** | $7,700 | $7,365 | $161 | $— | | |

(a) Equals aggregate bank commitments under revolving and bilateral credit agreements. See discussion below and Credit Agreements table below for items affecting effective program size.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have revolving credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its commercial paper outstanding does not reduce available capacity under a Registrant's credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the available capacity under its credit agreement.

The following table presents the short-term borrowings activity for Exelon during 2011, 2010 and 2009:

***Exelon***

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Average borrowings | $ 218 | $ 125 | $ 132 |
| Maximum borrowings outstanding | 600 | 346 | 523 |
| Average interest rates, computed on a daily basis | 0.50% | 0.72% | 0.73% |
| Average interest rates, at December 31 | 0.44% | n.a. | 0.69% |

***Credit Agreements***

On March 23, 2011, Exelon Corporate, Generation and PECO replaced their unsecured revolving credit facilities with new facilities with aggregate bank commitments of $500 million, $5.3 billion and $600 million, respectively. Under these facilities, Exelon, Generation and PECO may issue letters of credit in the aggregate amount of up to $200 million, $3.5 billion and $300 million, respectively. The credit facilities expire on March 23, 2016, unless extended in accordance with the terms of the agreements. Each credit facility permits the applicable borrower to request two one-year extensions. Each credit facility also allows Exelon, Generation and PECO to request increases in the aggregate commitments up to an additional $250 million, in the case of each of Exelon and PECO, and up to an additional $1 billion in the case of Generation. Any such extensions or increases are subject to the approval of the lenders party to the credit facilities in their sole discretion. Exelon Corporate, Generation and PECO incurred $3 million, $37 million and $4 million, respectively, in costs related to the replacement of their credit facilities. These costs included upfront and arranger fees, as well as other costs such as external legal fees and filing costs. These costs will be amortized to interest expense over the terms of the credit facilities.

As of December 31, 2011, ComEd had access to an unsecured revolving credit facility with aggregate bank commitments of $1 billion that expires on March 25, 2013, unless extended in accordance with its terms. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $1 billion. ComEd may request two additional one-year extensions. In addition, ComEd may request increases in the aggregate bank commitments under its credit facility up to an additional $500 million. Any such extensions or increases are subject to the approval of the lenders party to the credit facility in their sole discretion. ComEd expects to refinance their unsecured revolving credit facility in the first half of 2012.

An event of default under any of the Registrants' credit facilities would not constitute an event of default under any of the other Registrants' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation under its credit facility would constitute an event of default under the Exelon corporate credit facility.

At December 31, 2011, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under the credit agreements:

| | | | | Available Capacity at December 31, 2011 | | Average Interest Rate on Facility Borrowings |
|---|---|---|---|---|---|---|
| **Borrower** | **Aggregate Bank Commitment (a)** | **Facility Draws** | **Outstanding Letters of Credit** | **Actual** | **To Support Additional Commercial Paper** | **for the year ended December 31, 2011** |
| Exelon Corporate | $ 500 | $— | $ 7 | $ 493 | $ 332 | n.a. |
| Generation | 5,600 | — | 876 | 4,724 | 4,724 | n.a. |
| ComEd | 1,000 | — | 1 | 999 | 999 | n.a. |
| PECO | 600 | — | 1 | 599 | 599 | n.a. |
| **Total** | $7,700 | $— | $885 | $6,815 | $6,654 | |

(a) Excludes additional credit facility agreements for Generation, ComEd and PECO with aggregate commitments of $50 million, $34 million and $34 million, respectively, arranged with minority and community banks located primarily within ComEd's and PECO's service territories. These facilities expire on October 19, 2012 and are solely for issuing letters of credit. As of December 31, 2011, letters of credit issued under these agreements totaled $25 million, $21 million and $20 million for Generation, ComEd and PECO, respectively.

n.a. Not applicable.

Borrowings under each credit agreement bear interest at a rate selected by the borrower based upon either the prime rate or at a fixed rate for a specified period based upon a LIBOR-based rate. The Exelon, Generation and PECO agreements provide for adders of up to 85 basis points for prime-based borrowings and up to 185 basis points for the LIBOR-based borrowings based upon the credit rating of the borrower. At December 31, 2011, Exelon, Generation and PECO adders were 30, 30 and 10 basis points, respectively, for prime based borrowings and 130, 130 and 110 basis points, respectively, for LIBOR-based borrowings. The ComEd agreement provides adders of up to 137.5 basis points for prime-based borrowings and up to 237.5 basis points for LIBOR-based borrowings to be added, based upon ComEd's credit rating. At December 31, 2011, ComEd's adder was 87.5 basis points for prime based borrowings and 187.5 basis points for LIBOR-based borrowings.

Additionally, on November 4, 2010, Generation entered into a bilateral credit facility, which provides for an aggregate commitment of up to $500 million. The effectiveness and full availability of the credit facility were subject to various conditions. On February 22, 2011, Generation satisfied all conditions to the effectiveness and availability of credit under the credit facility for loans and letters of credit in the aggregate maximum amount of $300 million, which is the limit currently authorized by the board of directors of Exelon for this credit facility. Availability under the bilateral credit facility extends through December 2015 for $150 million of the $300 million commitment and March 2016 for the remaining $150 million. The bilateral credit facility will be used by Generation primarily to meet requirements for letters of credit, but also permits cash borrowings at a rate of LIBOR or a base rate, plus an adder of 200 basis points. No cash borrowings are anticipated under the credit facility. In addition, Generation will pay a facility fee, payable on the first day of each calendar quarter at a rate per annum equal to a specified facility fee rate on the total amount of the credit facility regardless of usage.

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, 2011:

| | 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, 2011 the interest coverage ratios at the Registrants were as follows:

| | Exelon | Generation | ComEd | PECO |
|---|---|---|---|---|
| Interest coverage ratio | 15.60 | 27.98 | 6.39 | 8.21 |

**Accounts Receivable Agreement**

PECO is party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its customer accounts receivable designated under the agreement in exchange for proceeds of $225 million, which is classified as a short-term note payable on Exelon's Consolidated Balance Sheets. As of December 31, 2011 and 2010, the financial institution's undivided interest in Exelon's and PECO's customer accounts receivable was equivalent to $329 million and $346 million, respectively, which is calculated under the terms of the agreement. Upon termination or liquidation of this agreement, the financial institution is entitled to recover up to $225 million plus the accrued yield payable from its undivided interest in PECO's receivables. On September 2, 2011, PECO extended this agreement, which now terminates on August 31, 2012. As of December 31, 2011, PECO was in compliance with the requirements of the agreement. In the event the agreement is not further extended, PECO has sufficient short-term liquidity and may seek alternate financing.

***Long-Term Debt***

The following table presents the outstanding long-term debt at Exelon as of December 31, 2011 and 2010:

| | Rates | Maturity Date | December 31, 2011 | December 31, 2010 |
|---|---|---|---|---|
| **Long-term debt** | | | | |
| First Mortgage Bonds [(a)] [(b)]: | | | | |
| Fixed rates | 1.65% - 7.65% | 2012-2038 | $ 7,522 | $ 6,917 |
| Floating rates | 0.24% - 0.27% | 2017-2021 | — | 191 |
| Senior unsecured notes | 4.90% - 6.25% | 2014-2041 | 4,902 | 4,902 |
| Notes payable and other [(c)] | 6.95% - 7.83% | 2012-2020 | 174 | 176 |
| Pollution control notes: | | | | |
| Fixed rates | 5.00% | 2042 | 46 | 46 |
| Sinking fund debentures | 4.75% | 2011 | — | 2 |
| **Total long-term debt** | | | 12,644 | 12,234 |
| Unamortized debt discount and premium, net | | | (32) | (34) |
| Unamortized settled fair value hedge, net | | | — | (1) |
| Fair value hedge carrying value adjustment, net | | | 15 | 14 |
| Long-term debt due within one year | | | (828) | (599) |
| **Long-term debt** | | | $11,799 | $11,614 |
| **Long-term debt to financing trusts [(d)]** | | | | |
| Subordinated debentures to ComEd Financing III | 6.35% | 2033 | $ 206 | $ 206 |
| Subordinated debentures to PECO Trust III | 7.38% | 2028 | 81 | 81 |
| Subordinated debentures to PECO Trust IV | 5.75% | 2033 | 103 | 103 |
| **Total long-term debt to financing trusts** | | | $ 390 | $ 390 |

(a) Substantially all of ComEd's assets other than expressly excepted property and substantially all of PECO's assets are subject to the liens of their respective mortgage indentures.
(b) Includes First Mortgage Bonds issued under the ComEd and PECO mortgage indentures securing pollution control bonds and notes.
(c) Includes capital lease obligations of $34 million and $36 million at December 31, 2011 and 2010, respectively. Lease payments of $3 million, $3 million, $3 million, $3 million, $4 million and $18 million will be made in 2012, 2013, 2014, 2015, 2016 and thereafter, respectively.
(d) Amounts owed to these financing trusts are recorded as debt to financing trusts within Exelon's Consolidated Balance Sheets.

Long-term debt maturities at Exelon in the periods 2012 through 2016 and thereafter are as follows:

| Year | |
|---|---|
| 2012 | $ 828 |
| 2013 | 555 |
| 2014 | 1,370 |
| 2015 | 1,063 |
| 2016 | 669 |
| Thereafter | 8,549[a] |
| Total | $13,034 |

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

***Antelope Valley Project Development Debt Agreement***

The DOE Loan Programs Office issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project is expected to be completed at the end of 2013. The loan will mature on January 5, 2037. Interest rates on the loan will be fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity. As of December 31, 2011, no draws had been made on the loan.

In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2011, Generation had $690 million in letters of credit outstanding related to the project, which included approximately $635 million letters of credit issued by Generation on December 21, 2011 to support its equity investment in the project prior to the initial loan advance to Antelope Valley. Due to a delay in the initial loan funding, Generation has reduced the outstanding letters of credit. As of February 8, 2012, Generation had $5 million in letters of credit outstanding related to the project. See Note 3—Merger and Acquisitions for additional information on Antelope Valley.

In connection with this agreement, Generation entered into a floating-for-fixed interest rate swap with a notional amount of $485 million to mitigate interest rate risk associated with the financing. See Note 6—Derivative Financial Instruments for additional information on the interest rate swap. See Note 4—Accounts Receivable for information regarding PECO's accounts receivable agreement. See Note 9—Derivative Financial Instruments for additional information regarding interest rate swaps. See Note 15—Preferred Securities for additional information regarding preferred securities.

## 11. Income Taxes

Income tax expense (benefit) from operations is comprised of the following components:

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Included in operations: | | | |
| Federal | | | |
| Current | $ 1 | $ 506 | $ 803 |
| Deferred | 1,200 | 972 | 775 |
| Investment tax credit amortization | (12) | (12) | (12) |
| State | | | |
| Current | (3) | 171 | 154 |
| Deferred | 271 | 21 | (8) |
| Total | $1,457 | $1,658 | $1,712 |

The effective income tax rate from operations varies from the U.S. Federal statutory rate principally due to the following:

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| U.S. Federal statutory rate | 35.0% | 35.0% | 35.0% |
| Increase (decrease) due to: | | | |
| State income taxes, net of Federal income tax benefit | 4.4 | 3.0 | 2.1 |
| Qualified nuclear decommissioning trust fund income | 0.5 | 1.7 | 3.1 |
| Domestic production activities deduction | (0.3) | (1.2) | (0.9) |
| Tax exempt income | (0.2) | (0.1) | (0.1) |
| Health care reform legislation | (0.2) | 1.4 | — |
| Nontaxable postretirement benefits | — | — | (0.2) |
| Amortization of investment tax credit | (0.3) | (0.3) | (0.2) |
| Production tax credits | (0.9) | — | — |
| Plant basis differences | (1.0) | — | — |
| Other | (0.1) | (0.2) | (0.1) |
| Effective income tax rate | 36.9% | 39.3% | 38.7% |

The tax effects of temporary differences, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2011 and 2010 are presented below:

| | For the Year Ended December 31, | |
|---|---|---|
| | 2011 | 2010 |
| Plant basis differences | $(7,803) | $(5,931) |
| Unrealized gains on derivative financial instruments | (468) | (523) |
| Deferred pension and post-retirement obligation | 665 | 485 |
| Nuclear decommissioning activities | (452) | (444) |
| Deferred debt refinancing costs | (37) | (46) |
| Goodwill | — | 4 |
| Other, net | 41 | (39) |
| Deferred income tax liabilities (net) | $(8,054) | $(6,494) |
| Unamortized investment tax credits | (200) | (212) |
| Total deferred income tax liabilities (net) and unamortized investment tax credits | $(8,254) | $(6,706) |

The following table provides Exelon's carryforwards and any corresponding valuation allowances as of December 31, 2011.

| As of December 31, 2011 | |
|---|---|
| State net operating loss carryforward | $679[a] |
| Deferred taxes | 31 |
| Valuation allowance | 10 |

(a) Exelon's state net operating loss carryforwards will expire beginning in 2019.

### ***Tabular reconciliation of unrecognized tax benefits***

The following table provides a reconciliation of the Registrants' unrecognized tax benefits as of December 31, 2011, 2010 and 2009:

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Unrecognized tax benefits at the beginning of year | $787 | $1,498 | $1,495 |
| Increases based on tax positions related to the current year | 5 | 1 | — |
| Decreases based on tax positions related to the current year | — | (2) | (2) |
| Change to positions that only affect timing | 21 | (262) | 19 |
| Increases based on tax positions prior to the current year | — | 8 | 4 |
| Decreases based on tax positions prior to the current year | (3) | (3) | — |
| Decreases related to settlements with taxing authorities | — | (452) | (18) |
| Decrease from expiration of statute of limitations | (3) | (1) | — |
| Unrecognized tax benefits at end of year | $807 | $ 787 | $1,498 |

Included in Exelon's unrecognized tax benefits balance at December 31, 2011 and 2010 are approximately $804 million and $783 million, respectively, of tax positions for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits. The disallowance of such positions would not materially affect the annual effective tax rate but would accelerate the payment of cash to or defer the receipt of the cash tax benefit from the taxing authority to an earlier or later period respectively.

### ***Unrecognized tax benefits that if recognized would affect the effective tax rate***

Exelon and Generation have $3 million and $3 million, respectively, of unrecognized tax benefits at December 31, 2011 that, if recognized, would decrease the effective tax rate. Exelon and Generation had $4 million and $4 million, respectively, of unrecognized tax benefits at December 31, 2010 that, if recognized, would decrease the effective tax rate.

### ***Total amounts of interest and penalties recognized***

The following table represents the net interest receivable, including interest related to uncertain tax positions reflected in Exelon's Consolidated Balance Sheets.

| Net interest receivable as of | |
|---|---|
| December 31, 2011 | $74 |
| December 31, 2010 | 21 |

The following table sets forth the net interest expense, including interest related to uncertain tax positions, recognized in interest expense (income) in other income and deductions in the Registrants' Consolidated Statements of Operations. Exelon has not accrued any penalties with respect to uncertain tax positions.

| Net interest expense (income) for the years ended | |
|---|---|
| December 31, 2011 | $ (56) |
| December 31, 2010 | 110 |
| December 31, 2009 | (42) |

### ***Reasonably possible that total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date***

*Nuclear Decommissioning Liabilities*

AmerGen filed income tax refund claims taking the position that nuclear decommissioning liabilities assumed as part of its acquisition of nuclear power plants are taken into account in determining the tax basis in the assets it acquired. The additional basis results primarily in reduced capital gains or increased capital losses on the sale of assets in nonqualified decommissioning funds and increased tax depreciation and amortization deductions. The IRS disagrees with this position and has disallowed the claims. In

November 2008, Generation received a final determination from the Appeals division of the IRS (IRS Appeals) disallowing AmerGen's refund claims. On February 20, 2009, Generation filed a complaint in the United States Court of Federal Claims to contest this determination. In August 2009, the United States Department of Justice (DOJ) filed its answer denying the allegations made by Generation in its complaint. No trial date has yet been assigned, but trial could occur sometime in 2012.

The trial judge assigned to the case has noted the availability of the court's Alternative Dispute Resolution (ADR) program as an alternative to a trial, but the parties have not yet met with the ADR judge. The ADR program is a non-binding process that utilizes a variety of techniques such as mediation, neutral evaluation, and non-binding arbitration that allow the parties to understand better their differences and their prospects for settlement. The DOJ presently refuses to commit to participate in ADR. As a result, it is unclear whether ADR will occur and if so, when.

In addition, in the second quarter of 2010, Entergy Corporation concluded its trial in the United States Tax Court of a similar dispute involving the assumption of decommissioning liabilities in connection with the purchase of a nuclear power plant. It is possible that a decision will be reached in that case in the next twelve months. While the decision in that case would not serve as binding precedent for AmerGen's litigation in the United States Court of Federal Claims, the reasoning of the decision may cause Generation to reevaluate the total amount of unrecognized tax benefits. Due to the possibility of quicker resolution through the ADR program and the possibility of a decision being entered in the Entergy trial, Generation believes that it is reasonably possible that the total amount of unrecognized tax benefits may significantly decrease in the next twelve months.

*Tax Method of Accounting for Repairs*

In 2009, Exelon received approval from the IRS to change its method of accounting for repair costs associated with Generation's power plants. The new tax method of accounting resulted in net positive cash flow for of approximately $210 million and approximately $160 million for 2011 and 2010, respectively. Although the IRS granted Exelon approval to change its method of accounting, the approval did not affirm the methodology used to calculate the deduction. Exelon had requested and received approval from the IRS to review its methodology through its Pre-Filing Agreement program. However, in the second quarter of 2010, Exelon was informed that the IRS suspended the Pre-Filing agreement process and instead intends to issue broad industry guidance with respect to electric generation power plants. If that broader guidance is issued, it is reasonably possible that the total amount of unrecognized tax benefits could increase or decrease within the next 12 months.

See 1999 Sale of Fossil Generating Assets in Other Tax Matters – IRS Appeals 1999-2001 section below for information regarding the amount of unrecognized tax benefits associated with this matter that could change significantly within the next 12 months.

See Competitive Transition Charges in Other Tax Matters – IRS Appeals 1999-2001 section below for information regarding the amount of unrecognized tax benefits associated with this matter that could change significantly within the next 12 months.

### *Description of tax years that remain subject to examination by major jurisdiction*

| Taxpayer | Open Years |
|---|---|
| Exelon (and predecessors) and subsidiaries consolidated Federal income tax returns | 1999-2010 |
| Exelon and subsidiaries Illinois unitary income tax returns | 2007-2010 |
| Exelon Pennsylvania corporate net income tax returns | 2006-2010 |
| PECO Pennsylvania corporate net income tax returns | 2008-2010 |

**Other Tax Matters**

### *IRS Appeals 1999-2001*

*1999 Sale of Fossil Generating Assets* Exelon, through its ComEd subsidiary, took two positions on its 1999 income tax return to defer approximately $2.8 billion of tax gain on the 1999 sale of ComEd's fossil generating assets. Exelon deferred approximately $1.6 billion of the gain under the involuntary conversion provisions of the IRC. Exelon believes that it was economically compelled to dispose of ComEd's fossil generating plants as a result of the Illinois Act and that the proceeds from the sale of the fossil plants were properly reinvested in qualifying replacement property such that the gain could be deferred over the lives of the replacement property under the involuntary conversion provisions. The remaining approximately $1.2 billion of the gain was deferred by reinvesting the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities.

Exelon received the IRS audit report for 1999 through 2001, which reflected the full disallowance of the deferral of gain associated with both the involuntary conversion position and the like-kind exchange transaction. Specifically, the IRS asserted that ComEd was not forced to sell the fossil generating plants and the sales proceeds were therefore not received in connection with an involuntary conversion of certain ComEd property rights. Accordingly, the IRS asserted that the gain on the sale of the assets was fully subject to tax. The IRS also asserted that the Exelon purchase and leaseback transaction is substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax.

*Competitive Transition Charges.* Exelon contended that the Illinois Act and the Competition Act resulted in the taking of certain of ComEd's and PECO's assets used in their respective businesses of providing electricity services in their defined service areas. Exelon has filed refund claims with the IRS taking the position that CTCs collected during ComEd's and PECO's transition periods represent compensation for that taking and, accordingly, are excludible from taxable income as proceeds from an involuntary conversion. The tax basis of property acquired with the funds provided by the CTCs would be reduced such that the benefits of the position are temporary in nature. The IRS disallowed the refund claims for the 1999-2001 tax years.

Under the Illinois Act, ComEd was required to allow competitors the use of its distribution system resulting in the taking of ComEd's assets and lost asset value (stranded costs). As compensation for the taking, ComEd was permitted to collect a portion of the stranded costs through the collection of CTCs from those customers electing to purchase electricity from providers other than ComEd. ComEd collected approximately $1.2 billion in CTCs for the years 1999-2006.

Similarly, under the Competition Act, PECO was required to allow others the use of its distribution system resulting in the taking of PECO's assets and the stranded costs. Pennsylvania permitted PECO to collect CTCs as compensation for its stranded costs. The PAPUC determined the total amount of stranded costs that PECO was permitted to collect through the CTCs to be $5.3 billion.

*2009 Status of Tax Positions.* During 2009, Exelon held discussions with IRS Appeals in an attempt to reach a settlement on both the involuntary conversion and like-kind exchange positions, in a manner commensurate with Exelon's and the IRS' respective hazards of litigation with respect to each issue. During the second quarter of 2009, Exelon determined that a settlement with IRS Appeals was unlikely and that Exelon would be required to initiate litigation in order to resolve the issues. Accordingly, Exelon concluded that it had sufficient new information that a remeasurement of these two positions was required in accordance with applicable accounting standards. As a result, Exelon recorded a $31 million (after-tax) interest benefit of which $40 million (after-tax) was recorded at ComEd. The difference in amounts recorded at Exelon and ComEd is due to the method of allocating interest to the Registrants.

Due to the fact that tax litigation often results in a negotiated settlement, as of December 31, 2009, Exelon believed that an eventual settlement on the involuntary conversion position remained a likely outcome. Therefore, Exelon and ComEd established a liability for an unrecognized tax benefit consistent with their view as to a likely settlement.

With regard to the like-kind exchange transaction, as of December 31, 2009, Exelon believed it was likely that the issue would be fully litigated. Exelon assessed in accordance with accounting standards whether it would prevail in litigation. While Exelon recognized the complexity and hazards of this litigation, it believed that it was more likely than not that it would prevail in such litigation and therefore eliminated any liability for unrecognized tax benefits.

In addition to attempting to impose tax on the transactions, the IRS had asserted penalties of approximately $196 million for a substantial understatement of tax. Because Exelon believed it was unlikely that the penalty assertion would ultimately be sustained, Exelon and ComEd had not recorded a liability for penalties as of December 31, 2009.

*2010 Status of Tax Positions.* In connection with Exelon's discussions with IRS Appeals during the second quarter of 2010, IRS Appeals proposed a settlement offer for the like-kind exchange transaction and involuntary conversion and CTC positions.

Based on the status of these settlement discussions, Exelon concluded that it had sufficient new information that a remeasurement of the involuntary conversion and CTC positions was required in accordance with applicable accounting standards. As a result of the required re-measurement in the second quarter of 2010, Exelon recorded $65 million (after-tax) of interest expense, of which $36 million (after-tax) and $22 million (after-tax) were recorded at ComEd and PECO, respectively. ComEd also recorded a current tax expense of $70 million offset with a tax benefit recorded at Generation of $70 million. In the third quarter of 2010, Exelon and IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions. The agreement is consistent with IRS Appeals' second quarter 2010 offer to settle the involuntary conversion and CTC positions and also includes IRS Appeals' agreement to withdraw its assertion of the $110 million substantial understatement penalty with respect to Exelon's involuntary conversion position. Final resolution of the involuntary conversion and CTC disputes remains subject to finalizing terms and calculations and executing definitive agreements satisfactory to both parties. As a result of the preliminary agreement, Exelon and ComEd eliminated any liability for unrecognized tax benefits and established a current tax payable to the IRS.

*2011 Status of Tax Positions.* Under the terms of the preliminary agreement, Exelon estimates that the IRS will assess tax and interest of approximately $300 million in 2012 for the years for which there is a resulting tax deficiency, of which $405 million would be paid by ComEd, $135 million would be received by PECO, $10 million would be paid by Generation and the remainder received by Exelon. These amounts are net of approximately $300 million of refunds due from the settlement of the 2001 tax method of accounting change for certain overhead costs under the SSCM as well as other agreed upon audit adjustments. In order to stop additional interest from accruing on the expected assessment, Exelon made a payment in December 2010 to the IRS of $302 million. During 2011, ComEd reimbursed Exelon for this amount. Further, Exelon expects to receive additional tax refunds of approximately $365 million between 2012 and 2014, of which $55 million and $335 million would be received by Generation and ComEd, respectively, and the remainder paid by Exelon.

Exelon and IRS Appeals to date have failed to reach a settlement with respect to the like-kind exchange position. Exelon continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO and does not believe that the concession demanded by the IRS in its settlement offer reflects the strength of Exelon's position. IRS Appeals also continues to assert an $86 million penalty for a substantial understatement of tax with respect to the like-kind exchange position.

While Exelon has been and remains willing to settle the issue in a manner generally commensurate with its hazards of litigation, the IRS has thus far been unwilling to settle the issue without requiring a nearly complete concession of the issue by Exelon. Accordingly, to continue to contest the IRS's disallowance of the like-kind exchange position and its assertion of the $86 million substantial understatement penalty, Exelon expects to initiate litigation in 2012 after the final resolution of the involuntary conversion and CTC settlement. Given that Exelon has determined settlement is not a realistic outcome, it has assessed in accordance with applicable accounting standards whether it will prevail in litigation. While Exelon recognizes the complexity and hazards of this litigation, it believes that it is more likely than not that it will prevail in such litigation and therefore eliminated any liability for unrecognized tax benefits. Further, Exelon believes it is unlikely that the penalty assertion will ultimately be sustained, Exelon and ComEd have not recorded a liability for penalties. However, should the IRS prevail in asserting the penalty it would result in an after-tax charge of $86 million to Exelon's and ComEd's results of operations.

As of December 31, 2011, assuming Exelon's preliminary settlement of the involuntary conversion position is finalized, the potential tax and interest, exclusive of penalties, that could become currently payable in the event of a fully successful IRS challenge to Exelon's like-kind exchange position could be as much as $860 million, of which $550 million would be paid by ComEd and the remainder by Exelon. If the IRS were to prevail in litigation on the like-kind exchange position, Exelon's results of operations could be negatively affected due to increased interest expense, as of December 31, 2011, by as much as $260 million (after-tax), of which $200 million would be recorded at ComEd and the remainder by Exelon. Litigation could take several years such that the estimated cash and interest impacts would likely change by a material amount.

Based on Exelon management's expectations as to the potential of a settlement and litigation outcome, it is reasonably possible that the unrecognized tax benefits related to these issues may significantly change within the next 12 months. It is not possible at this time to predict the amount, if any, of such a change.

### *Nuclear Decommissioning Trust Fund Special Transfer Tax Deduction*

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 NDT fund to a qualified NDT fund. As a result of temporary guidance published by the U.S. Department of Treasury, Generation completed a special transfer in the first quarter of 2008 for tax year 2008. In December 2010, the U.S. Department of Treasury issued final regulations under IRC Section 468A. The final regulations included a transitional relief provision that allowed taxpayers to request permission from the IRS to designate a taxable year, as far back as 2006, during which the special transfer will be deemed to have occurred. Exelon determined, and confirmed with the IRS through the ruling process, that this provision allows a majority of Generation's 2008 special transfer deduction to be claimed in the 2006 tax year and the remaining portions claimed ratably in taxable years 2007 and 2008. On February 18, 2011, in order to preserve both the ability to designate the special transfer from 2008 to an earlier taxable year and the ability to complete future additional special transfers, Exelon filed ruling requests with the IRS. During 2011, Exelon received favorable rulings from the IRS on all of its ruling requests. As a result, Exelon recorded an interest and tax benefit of $46 million, net of tax including the impact on the manufacturer's deduction, in 2011 related to the special transfers completed in 2008 and 2011.

### *2011 Illinois State Tax Rate Legislation*

The Taxpayer Accountability and Budget Stabilization Act, (SB 2505), enacted into law in Illinois on January 13, 2011, increases the corporate tax rate in Illinois from 7.3% to 9.5% for tax years 2011 – 2014, provides for a reduction in the rate from 9.5% to 7.75% for tax years 2015 – 2024 and further reduces the rate from 7.75% to 7.3% for tax years 2025 and thereafter. Pursuant to the rate change, Exelon reevaluated its deferred state income taxes during the first quarter of 2011. Illinois' corporate income tax rate changes resulted in a charge to state deferred taxes (net of Federal taxes) during the first quarter of 2011 of $7 million, $11 million and $4 million for Exelon, Generation and ComEd, respectively. Exelon's and ComEd's charge is net of a regulatory asset of $15 million.

In 2011, the income tax rate change increased Exelon's Illinois income tax provision (net of Federal taxes) by approximately $7 million, of which $12 million and $5 million of additional tax relates to Exelon Corporate and Generation, respectively, and a $10 million benefit for ComEd. The 2011 tax benefit at ComEd reflects the impact of a 2011 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010 and the electric transmission and distribution property repairs deduction discussed below.

### *Long-Term State Tax Apportionment*

Exelon and Generation periodically review events that may significantly impact how income is apportioned among the states and, therefore, the calculation of Exelon's and Generation's deferred state income taxes. On April 16, 2009, the PAPUC approved PECO's electricity procurement proposal that has an impact on Exelon's and Generation's apportionment of income among the states. Accordingly, Exelon and Generation re-evaluated the impacts to deferred state taxes in the second quarter of 2009. The effect of such evaluations resulted in the recording of a non-cash deferred state tax benefit in the amount of $35 million, net of taxes. In 2010, Exelon performed a review of the long-term state tax rates and noted no significant events that would materially impact state apportionment. As such, there was no update to the long-term state apportionment rates in 2010. In 2011 as a result of the 2011 Illinois State Tax Rate Legislation discussed above, Exelon and Generation re-evaluated their long-term state tax apportionment for Illinois and all other states where they have state income tax obligations. The effect of revising the long-term state tax apportionment resulted in the recording of a deferred state tax expense during the first quarter of 2011 of $22 million and $11 million (net of Federal taxes) for Exelon and Generation, respectively. The long-term state tax apportionment also was revised in the fourth quarter of 2011 pursuant to long-term state tax apportionment policy, resulting in recording an additional deferred state tax expense of $1 million and a deferred state tax benefit of $8 million (net of Federal taxes) for Exelon and Generation, respectively.

### *Illinois Replacement Investment Tax Credits*

On February 20, 2009, the Illinois Supreme Court ruled in Exelon's favor in a case involving refund claims for Illinois investment tax credits. Responding to the Illinois Attorney General's petition for rehearing, on July 15, 2009, the Illinois Supreme Court modified its opinion to indicate that it was to be applied only prospectively, beginning in 2009. In the third quarter of 2009, Exelon, Generation and ComEd decreased their unrecognized tax benefits related to this position. On December 22, 2009, Exelon filed a Petition of Writ for Certiorari with the United States Supreme Court appealing the Illinois Supreme Court's July 15, 2009 modified opinion. On March 1, 2010, the United States Supreme Court announced that it would not review the Illinois Supreme Court's decision. As a result of the United States Supreme Court decision, Exelon, Generation and ComEd ceased reporting their unrecognized tax benefits as of March 31, 2010.

### *Pennsylvania Bonus Depreciation*

Pursuant to authoritative guidance issued by the Pennsylvania Department of Revenue on February 24, 2011, Exelon is permitted to deduct 100% bonus depreciation in Pennsylvania in the year that such depreciation is claimed and allowable for Federal purposes. For Federal purposes, qualifying property placed into service after September 8, 2010, and before January 1, 2012, is eligible for 100% bonus depreciation. During 2011, the bonus depreciation deduction resulted in a benefit of approximately $7 million, $1 million and $6 million associated with property placed in service in 2010 at Exelon, Generation and PECO, respectively.

### *Accounting for Electric Transmission and Distribution Property Repairs*

On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for repair costs associated with electric transmission and distribution property. ComEd intends to adopt the safe harbor in the Revenue Procedure for the 2011 tax year. PECO adopted the safe harbor for the 2010 tax year. For the year ended December 31, 2011, the adoption of the safe harbor resulted in a $35 million reduction to income tax expense at PECO, while Generation incurred additional income tax expense in the amount of $28 million due to a decrease in its manufacturer's deduction, which are reflected in the effective income tax rate reconciliation above in the plant basis differences and domestic production activities deduction lines, respectively. For Exelon, the adoption had a minimal effect on consolidated earnings. In addition, the adoption of the safe harbor will result in a cash tax benefit at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million and $95 million, respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million.

See Note 2—Regulatory Matters for discussion of the regulatory treatment prescribed in the 2010 electric distribution rate case settlement for PECO's cash tax benefit resulting from the application of the method change to years prior to 2010.

### *Allocation of Tax Benefits*

Generation, ComEd and PECO are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During 2011, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $30 million and $18 million, respectively. During 2011, ComEd did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of ComEd's 2011 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010 and the electric transmission and distribution property repairs deduction discussed above. During 2010, Generation, ComEd and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $60 million, $2 million and $43 million, respectively. During 2009, Generation, ComEd and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $57 million, $8 million and $27 million, respectively.

In addition, ComEd received a non-cash contribution to equity from Exelon of $11 million related to tax benefits associated with capital projects constructed by ComEd on behalf of Exelon and Generation.

## 12. Asset Retirement Obligations

### *Nuclear Decommissioning Asset Retirement Obligations*

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's Consolidated Balance Sheets, from January 1, 2010 to December 31, 2011:

| | |
|---|---|
| Nuclear decommissioning ARO at January 1, 2010 | $3,260 |
| Accretion expense | 191 |
| Net increase due to changes in estimated future cash flows | 624 |
| Extinguishment of Zion Station ARO | (768) |
| Costs incurred to decommission retired plants | (31) |
| Nuclear decommissioning ARO at December 31, 2010 [(a)] | 3,276 |
| Accretion expense | 209 |
| Net increase due to changes in estimated future cash flows | 198 |
| Costs incurred to decommission retired plants | (3) |
| Nuclear decommissioning ARO at December 31, 2011 [(a)] | $3,680 |

(a) Includes $5 million as the current portion of the ARO at December 31, 2011 and 2010, which is included in other current liabilities on Exelon's Consolidated Balance Sheets.

During 2011, Generation recorded a net increase in the ARO of $404 million primarily due to increases for accretion and an increase in the estimated costs to decommission the Oyster Creek and Zion nuclear units resulting from the completion of updated decommissioning cost studies received in 2011 and an increase in the expected long-term escalation rates for energy, partially offset by decreases in long-term escalation rates for labor and other costs as compared to prior study periods. The increase in the Zion nuclear unit ARO resulted in $28 million of expense, which is included in Exelon's Consolidated Statements of Operations and Comprehensive Income, as the Zion nuclear unit is retired, and as such, is unable to record increases to the ARO through an ARC. Additionally, the Zion nuclear unit is not subject to a regulatory agreement that would provide for offset of the expense.

During 2010, Generation recorded a net increase in the ARO of $16 million, primarily reflecting ZionSolutions' assumption of decommissioning and other liabilities for Zion Station (see discussion below); and increases for accretion and for updates to estimated future cash flows across all of Generation's units. Changes in estimated future cash flows increased the ARO by $624 million, including approximately $200 million associated with the accelerated timing of the Zion Station decommissioning. The remainder of the increase is the result of cost study estimate updates and the change in timing of general decommissioning activities at select sites in Generation's nuclear fleet, including revisions to the timing and amount of SNF disposal; partially offset by the impacts of lower escalation rates. This change in the ARO resulted in an immaterial impact to Exelon's Consolidated Statements of Operations and Comprehensive Income.

***Zion Station Decommissioning***

On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC. (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities associated with Zion Station. Pursuant to the ASA, ZionSolutions can periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. On July 14, 2011, three people filed a purported class action lawsuit in the United States District Court for the Northern District of Illinois naming ZionSolutions and Bank of New York Mellon as defendants and seeking, among other things, an accounting for use of NDT funds, an injunction against the use of NDT funds, the appointment of a trustee for the NDT funds, and the return of NDT funds to customers of ComEd to the extent legally entitled thereto. ZionSolutions and Bank of New York Mellon filed a motion to dismiss the complaint on September 13, 2011.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to pledged assets for Zion Station decommissioning within Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a payable to ZionSolutions in Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers. Generation has retained its obligation to transfer the SNF at Zion Station to the DOE for ultimate disposal and has a liability of approximately $65 million and $34 million at December 31, 2011 and 2010, respectively, which is included within the nuclear decommissioning ARO. Generation also has retained NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station. As of December 31, 2011 and 2010, the carrying value of the Zion Station pledged assets was approximately $734 million and $824 million, respectively, and the payable to Zion Solutions was approximately $691 million and $786 million, respectively. The payable excludes a liability recorded within Generation's Consolidated Balance Sheets in Exelon's 2011 Form 10-K related to the tax obligation on the unrealized activity associated with the Zion Station NDT funds. The NDT funds will be utilized to satisfy the tax obligations as gains and losses are realized. The current portion of the payable to ZionSolutions, included in other current liabilities within Generation's Consolidated Balance Sheets at December 31, 2011 and 2010 in Exelon's 2011 Form 10-K was $128 million and $127 million, respectively. ZionSolutions withdrew approximately $143 million and $5 million for Zion Station decommissioning costs during the years ended December 31, 2011 and 2010, respectively.

ZionSolutions leased the land associated with Zion Station from Generation pursuant to a Lease Agreement. Under the Lease Agreement, ZionSolutions has committed to complete the required decommissioning work according to an established schedule and will construct a dry cask storage facility on the land for the SNF currently held in SNF pools at Zion Station. Rent payable under the Lease Agreement is $1.00 per year, although the Lease Agreement requires ZionSolutions to pay property taxes associated with

Zion Station and penalty rents may accrue if there are unexcused delays in the progress of decommissioning work at Zion Station or the construction of the dry cask SNF storage facility. To reduce the risk of default by EnergySolutions or ZionSolutions, EnergySolutions provided a $200 million letter of credit to be used to fund decommissioning costs in the event the NDT assets are insufficient. EnergySolutions has also provided a performance guarantee and entered into other agreements that will provide rights and remedies for Generation and the NRC in the case of other specified events of default, including a special purpose easement for disposal capacity at the EnergySolutions site in Clive, Utah, for all LLRW volume of Zion Station.

***Nuclear Decommissioning Trust Fund Investments***

NDT funds have been established for each generating station unit to satisfy Generation's nuclear decommissioning obligations. NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with the former ComEd, former PECO and former AmerGen units have been funded with amounts collected from ComEd customers, PECO customers and the previous owners of the former AmerGen plants, respectively. Based on an ICC order, ComEd ceased collecting amounts from its customers to pay for decommissioning costs. PECO currently collects funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are expected to continue through the operating lives of the plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds. Every five years, PECO files a rate adjustment with the PAPUC reflecting updated fund balances and estimated decommissioning costs. The most recent rate adjustment occurred on January 1, 2008 and the effective rates currently yield annual collections of $29 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2013. With respect to the former AmerGen units, Generation does not collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from customers. Apart from the contributions made to the NDT funds from amounts collected from ComEd and PECO customers, Generation has not made contributions to the NDT funds.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation. Generation has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds, on an aggregate basis for all former PECO units, compared to decommissioning obligations, as well as 5% of any additional shortfalls. This initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from ComEd customers for the former ComEd units or from the previous owners of the former AmerGen units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to the former AmerGen units, Generation retains any funds remaining in the NDTs after decommissioning.

At December 31, 2011 and 2010, Exelon and Generation had NDT fund investments totaling $6,507 million and $6,408 million, respectively.

During 2011, the NDT fixed income strategy shifted from solely core fixed income investments to a blend of Treasury Inflation Protected Securities (TIPS), investment-grade corporate credit and short-term corporate lending. There was no change in the equity investment strategy. At December 31, 2011, approximately 48% of the funds were invested in equity securities and 52% were invested in fixed income securities. At December 31, 2010, approximately 57% of the funds were invested in equity securities and 43% were invested in fixed income securities.

*Securities Lending Program.* Generation's NDT funds currently participate in a securities lending program with the funds' trustees. Under the program, securities loaned by the trustees are required to be collateralized by cash, U.S. Government securities or irrevocable bank letters of credit. Initial collateral levels are no less than 102% and 105% of the market value of the borrowed securities for collateral denominated in U.S. and foreign currency, respectively. Subsequent collateral levels must be maintained at a level no less than 100% of the market value of borrowed securities. Cash collateral received may not be sold or re-pledged by the trustees unless the borrower defaults.

In the fourth quarter of 2008, Exelon decided to end its participation in this securities lending program and initiated a gradual withdrawal of the trusts' investments in order to minimize potential losses due to liquidity constraints in the market. Currently, the weighted average maturity of the securities within the collateral pools is approximately 13 months. The fair value of securities on loan was approximately $20 million and $51 million at December 31, 2011 and 2010, respectively. The fair value of cash and non-cash collateral received for these loaned securities was $19 million and $51 million at December 31, 2011 and 2010, respectively. A portion of the income generated through the investment of cash collateral is remitted to the borrowers, and the remainder is allocated between the trusts and the trustees in their capacity as security agents.

*NRC Minimum Funding Requirements.* NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded on Exelon's Consolidated Balance Sheets primarily due to differences in the types of costs included in the estimates, the basis for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees.

Key assumptions used in the minimum funding calculation using the NRC methodology at December 31, 2011 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the plants cease operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals and with an assumed end-of-operations date of 2019 for Oyster Creek); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by Generation to determine the ARO and to forecast the target growth in the NDT funds at December 31, 2011 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site spent fuel maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain low-level radioactive waste); (3) the consideration of multiple scenarios where decommissioning activities are completed under three possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (4) the assumption plants cease operating at the end of an extended license life (assuming 20-year license renewal extensions, except Oyster Creek with an assumed end-of-operations date of 2019); (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 6.1% through a period of approximately 30 years after the end of the extended lives of the units; and (6) an estimated targeted annual pre-tax return on the NDT funds of 5.6% to 6.7% (as compared to a historical 5-year annual average pre-tax return of approximately 3.6%).

Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of the current approved license life), based on values as of December 31, addressing Generation's ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or make additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, Exelon's and Generation's cash flows and financial position may be significantly adversely affected.

On March 10, 2010, Generation notified the NRC that it had provided additional decommissioning funding assurance for its Byron Unit 2 and Braidwood Units 1 and 2 NDT funds with the establishment of approximately $44 million in parent guarantees in accordance with a plan submitted by Generation to the NRC on July 29, 2009. On May 26, 2010, the NRC notified Generation that additional parent guarantees may be required to meet the future value of the underfunded position. During the third quarter of 2010, Generation established approximately $175 million in additional parent guarantees.

On March 31, 2011, Generation, in its NRC-required biennial decommissioning funding status report, notified the NRC that adequate decommissioning funding assurance existed as of December 31, 2010 for Byron Unit 2 and Braidwood Units 1 and 2, without taking credit for any additional funding assurance provided by the parent guarantees, and Generation provided notice of its intention to cancel the parent guarantees following expiration of the NRC required notice period. Accordingly, Generation cancelled these parent guarantees on August 6, 2011. Additionally, in the March 31, 2011 report, Generation provided data from which the NRC concluded that the amount of decommissioning funding as of December 31, 2010 for Limerick Unit 1 was less than the amount required by the NRC's regulations. As Generation noted in its March 31, 2011 report, the funding mechanism used as the source of revenues for the Limerick Unit 1 NDT funds is a non-bypassable charge approved by the PAPUC authorizing PECO to continue to collect decommissioning funds from ratepayers for Generation. Generation is currently evaluating several options for addressing NRC funding assurance requirements. These options will not result in an increase to the non-bypassable charge and may include other financial guarantees, such as a parent company guarantee. Every five years, PECO files a cost adjustment with the PAPUC reflecting updated fund balances and estimated decommissioning costs. The next cost adjustment filing will be made in March 2012 and will be effective January 1, 2013.

As the future values of trust funds change due to market conditions, the NRC minimum funding status of Generation's units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO nuclear plants, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

*Accounting Implications of the Regulatory Agreements with ComEd and PECO.* Based on the regulatory agreement with the ICC that dictates Generation's obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis, as long as funds held in the NDT funds exceed the total estimated decommissioning obligation, decommissioning-related activities, including realized and unrealized gains and losses on the NDT funds and accretion of the decommissioning obligation, are generally offset within Exelon's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability. Should the value of the NDT fund for any former ComEd unit fall below the amount of the estimated decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to Exelon's and Generation's results of operations and financial position could be material. At December 31, 2011, the NDT funds of each of the former ComEd units exceeded the related decommissioning obligation for each of the units. For the purposes of making this determination, the decommissioning obligation referred to is the ARO reflected on Generation's Consolidated Balance Sheets at December 31, 2011 in Exelon's 2011 Form 10-K, and is different, as described above, from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

Based on the regulatory agreement supported by the PAPUC that dictates Generation's rights and obligations related to the shortfall or excess of trust funds necessary for decommissioning the seven former PECO nuclear units, regardless of whether the funds held in the NDT funds exceed or fall short of the total estimated decommissioning obligation, decommissioning-related activities are generally offset within Exelon's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, PECO has recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability. Any changes to the PECO regulatory agreements could impact Exelon's and Generation's ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon's and Generation's results of operations and financial position could be material.

The decommissioning-related activities related to the Clinton, Oyster Creek and Three Mile Island nuclear plants (the former AmerGen units) and the portions of the Peach Bottom nuclear plants that are not subject to regulatory agreements with respect to the NDT funds are reflected in Exelon's Consolidated Statements of Operations and Comprehensive Income, as there are no regulatory agreements associated with these units.

Refer to Note 19—Supplemental Financial Information and Note 21—Related Party Transactions for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

The following table provides unrealized gains (losses) on NDT funds for 2011, 2010 and 2009:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Net unrealized gains (losses) on decommissioning trust funds—Regulatory Agreement Units (a)(b) | $(74) | $294 | $799 |
| Net unrealized gains (losses) on decommissioning trust funds—Non-Regulatory Agreement Units (c) | (4) | 104 | 227 |

(a) Gains related to Generation's NDT funds associated with Regulatory Agreement Units are included in regulatory liabilities on Exelon's Consolidated Balance Sheets.

(b) Excludes $48 million and $20 million of gains related to the Zion Station pledged assets in 2011 and 2010. Gains related to Zion Station pledged assets are included in the payable for Zion Station decommissioning on Exelon's Consolidated Balance Sheets.

(c) Gains related to Generation's NDT funds associated with Non-Regulatory Agreement Units are included within Other, net in Exelon's Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units, which are subject to regulatory accounting, are eliminated within Other, net in Exelon's Consolidated Statement of Operations and Comprehensive Income.

**Non-Nuclear Asset Retirement Obligations**

Generation has AROs for plant closure costs associated with its fossil, hydroelectric and renewable generating stations, including asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of renewable generating stations and other decommissioning-related activities. ComEd and PECO have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1—Significant Accounting Policies for additional information on Exelon's accounting policy for AROs.

The following table provides a rollforward of the non-nuclear AROs reflected on the Exelon's Consolidated Balance Sheets from January 1, 2010 to December 31, 2011:

| | |
|---|---|
| Non-nuclear AROs at January 1, 2010 | $191 |
| Net increase (decrease) resulting from updates to estimated future cash flows (a) | 13 |
| Accretion expense (b) | 9 |
| Acquisition of Exelon Wind (c) | 13 |
| Payments | (3) |
| Non-nuclear AROs at December 31, 2010 | 223 |
| Net increase (decrease) resulting from updates to estimated future cash flows (a) | (19) |
| New development projects | 2 |
| Accretion expense (b) | 8 |
| Payments | (5) |
| Non-nuclear AROs at December 31, 2011 | $209 |

(a) ComEd and PECO recorded reductions in operating and maintenance expense of $10 million and $1 million, respectively, during the year ended December 31, 2010 and PECO recorded a reduction in operating and maintenance expense of $3 million during the year ended December 31, 2011 relating to updates to estimated future cash flows.

(b) For ComEd and PECO, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.

(c) Refer to Note 3—Acquisition for additional information regarding Exelon Wind.

**13. Retirement Benefits**

As of December 31, 2011, Exelon sponsored five qualified defined benefit pension plans, two non-qualified defined benefit pension plans and three other postretirement benefit plans for essentially all Generation, ComEd, PECO and BSC employees. Exelon's traditional and cash balance pension plans are intended to be tax-qualified defined benefit plans. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Exelon has elected that the trusts underlying these plans be treated under the IRC as qualified trusts. If certain conditions are met, Exelon can deduct payments made to the qualified trusts, subject to certain IRC limitations.

***Benefit Obligations, Plan Assets and Funded Status***

Exelon recognizes the overfunded or underfunded status of defined benefit pension and other postretirement benefit plans as an asset or liability on its balance sheet, with offsetting entries to Accumulated Other Comprehensive Income (AOCI) and regulatory assets, in accordance with the applicable authoritative guidance. The impact of changes in assumptions used to measure pension and other postretirement benefit obligations is generally recognized over the expected average remaining service period of the plan participants. The measurement date for the plans is December 31. The following table provides a rollforward of the changes in the benefit obligations and plan assets for the most recent two years for all plans combined:

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Change in benefit obligation: | | | | |
| Net benefit obligation at beginning of year | $12,524 | $11,482 | $3,874 | $3,658 |
| Service cost | 212 | 190 | 142 | 124 |
| Interest cost | 649 | 660 | 207 | 214 |
| Plan participants' contributions | — | — | 25 | 16 |
| Actuarial loss | 807 | 831 | 4 | 49 |
| Special termination benefits | — | — | — | 1 |
| Gross benefits paid | (654) | (639) | (201) | (198) |
| Federal subsidy on benefits paid | — | — | 11 | 10 |
| Net benefit obligation at end of year | $13,538 | $12,524 | $4,062 | $3,874 |
| Change in plan assets: | | | | |
| Fair value of net plan assets at beginning of year | $ 8,859 | $ 7,839 | $1,655 | $1,476 |
| Actual return on plan assets | 1,003 | 893 | 29 | 158 |
| Employer contributions | 2,094 | 766 | 277 | 203 |
| Plan participants' contributions | — | — | 25 | 16 |
| Benefits paid (a) | (654) | (639) | (189) | (198) |
| Fair value of net plan assets at end of year | $11,302 | $ 8,859 | $1,797 | $1,655 |

(a) Exelon's other postretirement benefits paid for the year ended December 31, 2011 are net of $12 million of reinsurance proceeds received from the Department of Health and Human Services as part of the Early Retiree Reinsurance Program pursuant to the Affordable Care Act of 2010.

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Other current liabilities | $ 42 | $ 7 | $ 2 | $ 1 |
| Pension obligations | 2,194 | 3,658 | — | — |
| Non-pension postretirement benefit obligations | — | — | 2,263 | 2,218 |
| Unfunded status (net benefit obligation less net plan assets) | $2,236 | $3,665 | $2,265 | $2,219 |

The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plan. The funded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following tables provide the projected benefit obligations (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for all pension plans with an ABO in excess of plan assets and a PBO in excess of plan assets.

| | PBO and ABO in excess of plan assets | |
|---|---|---|
| | 2011 | 2010 |
| Projected benefit obligation | $13,538 | $12,524 |
| Accumulated benefit obligation | 12,616 | 11,697 |
| Fair value of net plan assets | 11,302 | 8,859 |

On an ABO basis, the plans were funded at 90% at December 31, 2011 compared to 76% at December 31, 2010. On a PBO basis, the plans were funded at 83% at December 31, 2011 compared to 71% at December 31, 2010. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

***Components of Net Periodic Benefit Costs***

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2011, 2010 and 2009 for all plans combined. The table reflects a reduction in 2011, 2010 and 2009 of net periodic postretirement benefit costs of approximately $28 million, $38 million and $38 million, respectively, related to a Federal subsidy provided under the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Modernization Act), discussed further below.

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2011 | 2010 | 2009 |
| **Components of net periodic benefit cost:** | | | | | | |
| Service cost | $ 212 | $ 190 | $ 178 | $ 142 | $ 124 | $113 |
| Interest cost | 649 | 660 | 651 | 207 | 214 | 205 |
| Expected return on assets | (939) | (799) | (778) | (111) | (109) | (94) |
| Amortization of: | | | | | | |
| Transition obligation | — | — | — | 9 | 9 | 9 |
| Prior service cost (credit) | 14 | 14 | 14 | (38) | (56) | (56) |
| Actuarial loss | 331 | 254 | 197 | 66 | 74 | 87 |
| Curtailment/settlement charges | — | 5 | 6 | — | — | — |
| Special termination benefits | — | — | — | — | 1 | 4 |
| **Net periodic benefit cost** | $ 267 | $ 324 | $ 268 | $ 275 | $ 257 | $268 |

Through Exelon's postretirement benefit plans, Exelon provides retirees with prescription drug coverage. The Medicare Modernization Act, enacted on December 8, 2003, introduced a prescription drug benefit under Medicare as well as a Federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the Medicare prescription drug benefit. Management believes the prescription drug benefit provided under Exelon's postretirement benefit plans meets the requirements for the subsidy. See the *Health Care Reform Legislation* section below for further discussion regarding the income tax treatment of Federal subsidies of prescription drug benefits.

The effect of the subsidy on the components of net periodic postretirement benefit cost for the years ended December 31, 2011, 2010 and 2009 included in the consolidated financial statements was as follows:

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Amortization of the actuarial experience loss | $ 3 | $ 9 | $11 |
| Reduction in current period service cost | 9 | 10 | 9 |
| Reduction in interest cost on the APBO | 16 | 19 | 18 |
| Total effect of subsidy on net periodic postretirement benefit cost | $28 | $38 | $38 |

***Components of AOCI and Regulatory Assets***

Under the authoritative guidance for regulatory accounting, a portion of current year actuarial gains and losses and prior service costs (credits) is capitalized within Exelon's Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts, which would otherwise be recorded to AOCI. The following tables provide the components of AOCI and regulatory assets for the years ended December 31, 2011, 2010 and 2009 for all plans combined.

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2011 | 2010 | 2009 |
| **Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets:** | | | | | | |
| Current year actuarial (gain) loss | $ 744 | $ 737 | $ (94) | $ 74 | $— | $(154) |
| Amortization of actuarial loss | (331) | (254) | (197) | (66) | (74) | (87) |
| Current year prior service cost | — | — | 2 | — | — | — |
| Amortization of prior service cost (credit) | (14) | (14) | (14) | 38 | 56 | 56 |
| Amortization of transition obligation | — | — | — | (9) | (9) | (9) |
| Settlements | — | (5) | (6) | — | — | — |
| **Total recognized in AOCI and regulatory assets [(a)]** | $ 399 | $ 464 | $(309) | $ 37 | $(27) | $(194) |

(a) Of the $399 million related to pension benefits, $181 million and $218 million were recognized in AOCI and regulatory assets, respectively, during 2011. Of the $37 million related to other postretirement benefits, $13 million and $24 million were recognized in AOCI and regulatory assets, respectively, during 2011. Of the $464 million related to pension benefits, $310 million and $154 million were recognized in AOCI and regulatory assets, respectively, during 2010. Of the $(27) million related to other postretirement benefits, $(9) million and $(18) million were recognized in AOCI and regulatory assets, respectively, during 2010. Of the $(309) related to pension benefits, $(204) million and $(105) million were recognized in AOCI and regulatory assets, respectively, during 2009. Of the $(194) million related to other postretirement benefits, $(85) million and $(109) million were recognized in AOCI and regulatory assets, respectively, during 2009.

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 at December 31, 2011 and 2010, respectively, for all plans combined:

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Transition obligation | $ — | $ — | $ 11 | $ 20 |
| Prior service cost (credit) | 90 | 104 | (16) | (54) |
| Actuarial loss | 6,729 | 6,316 | 963 | 955 |
| Total [(a)] | $6,819 | $6,420 | $958 | $921 |

(a) Of the $6,819 million related to pension benefits, $4,311 million and $2,508 million are included in AOCI and regulatory assets, respectively, at December 31, 2011. Of the $958 million related to other postretirement benefits, $475 million and $483 million are included in AOCI and regulatory assets, respectively, at December 31, 2011. Of the $6,420 million related to pension benefits, $4,129 million and $2,291 million are included in AOCI and regulatory assets, respectively, at December 31, 2010. Of the $921 million related to other postretirement benefits, $462 million and $459 million are included in AOCI and regulatory assets, respectively, at December 31, 2010.

The following table provides the components of Exelon's AOCI and regulatory assets at December 31, 2011 (included in the table above) that are expected to be amortized as components of periodic benefit cost in 2012. These estimates are subject to the completion of an actuarial valuation of Exelon's pension and other postretirement benefit obligations, which will reflect actual census data as of January 1, 2012 and actual claims activity as of December 31, 2011. The valuation is expected to be completed in the first quarter of 2012.

| | Pension Benefits | Other Postretirement Benefits |
|---|---|---|
| Transition obligation | $— | $ 10 |
| Prior service cost (credit) | 14 | (12) |
| Actuarial loss | 407 | 69 |
| Total [(a)] | $421 | $ 67 |

(a) Of the $421 million related to pension benefits at December 31, 2011, $252 million and $169 million are expected to be amortized from AOCI and regulatory assets in 2012, respectively. Of the $67 million related to other postretirement benefits at December 31, 2011, $32 million and $35 million are expected to be amortized from AOCI and regulatory assets in 2012, respectively.

***Assumptions***

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit and other postretirement plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Exelon's expected level of contributions to the plans, the long-term expected investment rate credited to employees of certain plans and the anticipated rate of increase of health care costs. Additionally, assumptions related to plan participants include the incidence of mortality, the expected remaining service period, the level of compensation and rate of compensation increases, employee age and length of service, among other factors. The impact of changes in assumptions used to measure pension and other postretirement benefit obligations is generally recognized over the expected average remaining service period of the plan participants.

*Expected Rate of Return.* In selecting the expected rate of return on plan assets, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by Exelon's target asset class allocations.

The following assumptions were used to determine the benefit obligations for all of the plans at December 31, 2011, 2010 and 2009. Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2011 | 2010 | 2009 |
| Discount rate | 4.74% | 5.26% | 5.83% | 4.80% | 5.30% | 5.83% |
| Rate of compensation increase | 3.75% | 3.75% | 4.00% | 3.75% | 3.75% | 4.00% |
| Mortality table | IRS required mortality table for 2012 funding valuation | IRS required mortality table for 2011 funding valuation | IRS required mortality table for 2010 funding valuation | IRS required mortality table for 2012 funding valuation | IRS required mortality table for 2011 funding valuation | IRS required mortality table for 2010 funding valuation |
| Health care cost trend on covered charges | N/A | N/A | N/A | 6.50% decreasing to ultimate trend of 5.00% in 2017 | 7.00% decreasing to ultimate trend of 5.00% in 2015 | 7.50% decreasing to ultimate trend of 5.00% in 2015 |

The following assumptions were used to determine the net periodic benefit costs for all the plans for the years ended December 31, 2011, 2010 and 2009:

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2011 | 2010 | 2009 |
| Discount rate | 5.26% | 5.83% | 6.09% | 5.30% | 5.83% | 6.09% |
| Expected return on plan assets | 8.00%(a) | 8.50%(a) | 8.50%(a) | 7.08%(a) | 7.83%(a) | 8.10%(a) |
| Rate of compensation increase | 3.75% | 4.00% | 4.00% | 3.75% | 4.00% | 4.00% |
| Mortality table | IRS required mortality table for 2011 funding valuation | IRS required mortality table for 2010 funding valuation | IRS required mortality table for 2009 funding valuation | IRS required mortality table for 2011 funding valuation | IRS required mortality table for 2010 funding valuation | IRS required mortality table for 2009 funding valuation |
| Health care cost trend on covered charges | N/A | N/A | N/A | 7.00% decreasing to ultimate trend of 5.00% in 2015 | 7.50% decreasing to ultimate trend of 5.00% in 2015 | 7.50% decreasing to ultimate trend of 5.00% in 2014 |

(a) Not applicable to pension and other postretirement benefit plans that do not have any plan assets.

Assumed health care cost trend rates have a significant effect on the costs reported for the other postretirement benefit plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

| | |
|---|---|
| Effect of a one percentage point increase in assumed health care cost trend: | |
| on 2011 total service and interest cost components | $ 75 |
| on postretirement benefit obligation at December 31, 2011 | 686 |
| Effect of a one percentage point decrease in assumed health care cost trend: | |
| on 2011 total service and interest cost components | (57) |
| on postretirement benefit obligation at December 31, 2011 | (521) |

***Health Care Reform Legislation***

In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers. One such provision reduces the deductibility, for Federal income tax purposes, of retiree health care costs to the extent an employer's postretirement health care plan receives Federal subsidies that provide retiree prescription drug benefits at least equivalent to those offered by Medicare. Although this change did not take effect immediately, Exelon was required to recognize the full accounting impact in their financial statements in the period in which the legislation was enacted. As a result, in the first quarter of 2010, Exelon recorded total after-tax charges of approximately $65 million to income tax expense to reverse deferred tax assets previously established. Of this total, Generation, ComEd and PECO recorded charges of $24 million, $11 million and $9 million, respectively. Additionally, as a result of this deductibility change for employers and other Health Care Reform provisions that impact the federal prescription drug subsidy options provided to employers, Exelon intends to make a change in the manner in which it receives prescription drug subsidies in 2013.

The Health Care Reform Acts also include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Although the excise tax does not go into effect until 2018, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Certain key assumptions are required to estimate the impact of the excise tax on Exelon's other postretirement benefit obligation, including projected inflation rates (based on the CPI) and whether pre- and post-65 retiree populations can be aggregated in determining the premium values of health care benefits. Exelon reflected its best estimate of the expected impact in its annual actuarial valuation.

***Contributions***

The following table provides contributions made by Exelon to the pension and other postretirement benefit plans:

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2011 [(a)] | 2010 [(a)] | 2009 [(a)] |
| Exelon | $2,094 | $766 | $441 | $277 | $203 | $157 |

(a) Exelon presents the cash contributions above net of Federal subsidy payments received on its Consolidated Statements of Cash Flows. Exelon received Federal subsidy payments of $11 million in 2011, $10 million in 2010, and $10 million in 2009.

Exelon plans to contribute approximately $96 million to its qualified pension plans in 2012. Exelon plans to make non-qualified pension plan benefit payments of approximately $42 million in 2012. Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification).

Unlike the qualified pension plans, Exelon's other postretirement plans are not subject to regulatory minimum contribution requirements. Management considers several factors in determining the level of contributions to Exelon's other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery). Exelon expects to contribute approximately $302 million to the other postretirement benefit plans in 2012.

During the first quarter of 2012, Exelon will receive an updated valuation of its pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2012 and will adjust the benefit obligations as necessary.

***Estimated Future Benefit Payments***

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2011 were:

| | Pension Benefits | Other Postretirement Benefits (a) |
|---|---|---|
| 2012 | $ 786 | $ 186 |
| 2013 | 680 | 178 |
| 2014 | 692 | 186 |
| 2015 | 723 | 194 |
| 2016 | 750 | 204 |
| 2017 through 2021 | 4,335 | 1,206 |
| Total estimated future benefit payments through 2021 | $7,966 | $2,154 |

(a) 2012 includes $9 million of Federal subsidy receipts provided through the Medicare Modernization Act.

***Plan Assets***

*Investment Strategy.* On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

In the second quarter of 2010, Exelon modified its pension investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. As a result of this modification, Exelon decreased investments in equity securities and increased investments in fixed income securities and alternative investments in order to achieve a balanced portfolio of liability hedging and return-generating assets. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses.

The change in the overall investment strategy would tend to lower the expected rate of return on plan assets in future years as compared to the previous strategy. Exelon used an EROA of 7.50% and 6.68% to estimate its 2012 pension and other postretirement benefit costs, respectively.

Exelon's pension and other postretirement benefit plan target asset allocations and December 31, 2011 and 2010 weighted average asset allocations were as follows:

**Pension Plans**

| | | Percentage of Plan Assets at December 31, | |
|---|---|---|---|
| **Asset Category** | **Target Allocation** | **2011** | **2010** |
| Equity securities | 30-40% | 32% | 45% |
| Fixed income securities | 35-55% | 47 | 41 |
| Alternative investments (a) | 20-30% | 21 | 14 |
| Total | | 100% | 100% |

**Other Postretirement Benefit Plans**

| Asset Category | Target Allocation | Percentage of Plan Assets at December 31, 2011 | 2010 |
|---|---|---|---|
| Equity securities | 40-50% | 37% | 54% |
| Fixed income securities | 35-45% | 53 | 45 |
| Alternative investments [(a)] | 10-20% | 10 | 1 |
| Total | | 100% | 100% |

(a) Alternative investments include private equity, hedge funds and real estate.

*Securities Lending Programs.* The majority of the benefit plans currently participate in a securities lending program with the trustees of the plans' investment trusts. Under the program, securities loaned to the trustees are required to be collateralized by cash, U.S. Government securities or irrevocable bank letters of credit. Initial collateral levels are no less than 102% and 105% of the market value of the borrowed securities for collateral denominated in U.S. and foreign currency, respectively. Subsequent collateral levels must be maintained at a level no less than 100% of the market value of borrowed securities. Cash collateral received may not be sold or re-pledged by the trustees unless the borrower defaults.

In the fourth quarter of 2008, Exelon decided to end its participation in this securities lending program and initiated a gradual withdrawal of the trusts' investments in order to minimize potential losses due to liquidity constraints in the market. Currently, the weighted average maturity of the securities within the collateral funds is approximately 7 months. The fair value of securities on loan was approximately $17 million and $46 million at December 31, 2011 and 2010, respectively. The fair value of cash and non-cash collateral received for these loaned securities was $17 million at December 31, 2011 and $47 million at December 31, 2010. A portion of the income generated through the investment of cash collateral is remitted to the borrowers, and the remainder is allocated between the trusts and the trustees in their capacity as security agents.

*Concentrations of Credit Risk.* Exelon evaluated its pension and other postretirement benefit plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2011. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2011, there were no significant concentrations (defined as greater than 10 percent of plan assets) of risk in Exelon's pension and other postretirement benefit plan assets.

***Fair Value Measurements***

The following table presents Exelon's pension and other postretirement benefit plan assets measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at December 31, 2011 and 2010:

| At December 31, 2011 (a)(b) | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Pension plan assets** | | | | |
| Cash equivalents | $ 8 | $ — | $ — | $ 8 |
| Equity securities: | | | | |
| Individually held | 1,985 | — | — | 1,985 |
| Commingled funds | — | 858 | — | 858 |
| Mutual funds | — | 389 | — | 389 |
| Equity securities subtotal | 1,985 | 1,247 | — | 3,232 |
| Fixed income securities: | | | | |
| Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies | 1,616 | 48 | — | 1,664 |
| Debt securities issued by states of the United States and by political subdivisions of the states | — | 88 | — | 88 |
| Foreign debt securities | — | 224 | — | 224 |
| Corporate debt securities | — | 2,561 | — | 2,561 |
| Federal agency mortgage-backed securities | — | 156 | — | 156 |
| Non-Federal agency mortgage-backed securities | — | 28 | — | 28 |
| Commingled funds | — | 202 | — | 202 |
| Mutual funds | — | 277 | — | 277 |
| Fixed income securities subtotal | 1,616 | 3,584 | — | 5,200 |
| Private equity | — | — | 672 | 672 |
| Hedge funds | — | — | 1,525 | 1,525 |
| Real estate | 207 | 125 | 229 | 561 |
| **Pension plan assets subtotal** | 3,816 | 4,956 | 2,426 | 11,198 |
| **Other postretirement benefit plan assets** | | | | |
| Cash equivalents | 73 | — | — | 73 |
| Equity securities: | | | | |
| Individually held | 110 | — | — | 110 |
| Commingled funds | — | 415 | — | 415 |
| Mutual funds | — | 171 | — | 171 |
| Equity securities subtotal | 110 | 586 | — | 696 |

| At December 31, 2011 [(a)] [(b)] | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Fixed income securities: | | | | |
| Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies | 26 | 3 | — | 29 |
| Debt securities issued by states of the United States and by political subdivisions of the states | — | 93 | — | 93 |
| Foreign debt securities | — | 4 | — | 4 |
| Corporate debt securities | — | 41 | — | 41 |
| Federal agency mortgage-backed securities | — | 34 | — | 34 |
| Non-Federal agency mortgage-backed securities | — | 7 | — | 7 |
| Commingled funds | — | 385 | — | 385 |
| Mutual funds | — | 256 | — | 256 |
| Fixed income securities subtotal | 26 | 823 | — | 849 |
| Private equity | — | — | 1 | 1 |
| Hedge funds | — | — | 157 | 157 |
| Real estate | 4 | 1 | 7 | 12 |
| **Other postretirement benefit plan assets subtotal** | 213 | 1,410 | 165 | 1,788 |
| **Total pension and other postretirement benefit plan assets** | $4,029 | $6,366 | $2,591 | $12,986 |

| At December 31, 2010 [(a)] [(b)] | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Pension plan assets** | | | | |
| Cash equivalents | $ 2 | $ — | $ — | $ 2 |
| Equity securities: | | | | |
| Individually held | 1,528 | — | — | 1,528 |
| Commingled funds | — | 2,161 | — | 2,161 |
| Mutual funds | — | 326 | — | 326 |
| Equity securities subtotal | 1,528 | 2,487 | — | 4,015 |
| Fixed income securities: | | | | |
| Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies | 1,144 | 20 | — | 1,164 |
| Debt securities issued by states of the United States and by political subdivisions of the states | — | 15 | — | 15 |
| Foreign debt securities | — | 73 | — | 73 |
| Corporate debt securities | — | 312 | — | 312 |
| Federal agency mortgage-backed securities | — | 226 | — | 226 |
| Non-Federal agency mortgage-backed securities | — | 82 | — | 82 |
| Commingled funds | — | 1,036 | — | 1,036 |
| Mutual funds | — | 666 | — | 666 |
| Fixed income securities subtotal | 1,144 | 2,430 | — | 3,574 |
| Private equity | — | — | 536 | 536 |
| Hedge funds | — | — | 329 | 329 |
| Real estate | 178 | — | 179 | 357 |
| **Pension plan assets subtotal** | 2,852 | 4,917 | 1,044 | 8,813 |

| At December 31, 2010 (a) (b) | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Other postretirement benefit plan assets** | | | | |
| Cash equivalents | — | — | — | — |
| Equity securities: | | | | |
| Individually held | 225 | — | — | 225 |
| Commingled funds | — | 447 | — | 447 |
| Mutual funds | — | 218 | — | 218 |
| Equity securities subtotal | 225 | 665 | — | 890 |
| Fixed income securities: | | | | |
| Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies | 25 | 1 | — | 26 |
| Debt securities issued by states of the United States and by political subdivisions of the states | — | 100 | — | 100 |
| Foreign debt securities | — | 1 | — | 1 |
| Corporate debt securities | — | 13 | — | 13 |
| Federal agency mortgage-backed securities | — | 41 | — | 41 |
| Non-Federal agency mortgage-backed securities | — | 7 | — | 7 |
| Commingled funds | — | 225 | — | 225 |
| Mutual funds | — | 331 | — | 331 |
| Fixed income securities subtotal | 25 | 719 | — | 744 |
| Hedge funds | — | — | 5 | 5 |
| Real estate | 8 | — | 8 | 16 |
| **Other postretirement benefit plan assets subtotal** | 258 | 1,384 | 13 | 1,655 |
| **Total pension and other postretirement benefit plan assets** | $3,110 | $6,301 | $1,057 | $10,468 |

(a) See Note 8—Fair Value of Assets and Liabilities for a description of levels within the fair value hierarchy.

(b) The total fair value of pension and other postretirement benefit plan assets excludes $55 million and $21 million of interest and dividends receivable and $57 million and $25 million related to pending sales transactions at December 31, 2011 and 2010, respectively. Additionally, the table excludes collateral fund assets of $17 million and $47 million and collateral liabilities of $17 million and $47 million at December 31, 2011 and 2010, respectively, in connection with the benefit plans' participation in securities lending programs.

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value for pension and other postretirement benefit plans for the years ended December 31, 2011 and 2010:

| | Hedge funds | Private equity | Real estate | Total |
|---|---|---|---|---|
| **Pension Assets** | | | | |
| Balance as of January 1, 2011 | $ 329 | $536 | $179 | $1,044 |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | (26) | 50 | 46 | 70 |
| Purchases, sales and settlements: | | | | |
| Purchases | 1,222 | 121 | 13 | 1,356 |
| Sales | — | (1) | (9) | (10) |
| Settlements | — | (34) | — | (34) |
| Balance as of December 31, 2011 | $1,525 | $672 | $229 | $2,426 |

| | Hedge funds | Private equity | Real estate | Total |
|---|---|---|---|---|
| **Other Postretirement Benefits** | | | | |
| Balance as of January 1, 2011 | $ 5 | $— | $ 8 | $ 13 |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | (3) | — | (1) | (4) |
| Purchases, sales and settlements: | | | | |
| Purchases | 155 | 1 | — | 156 |
| Sales | — | — | — | — |
| Settlements | — | — | — | — |
| Balance as of December 31, 2011 | $157 | $ 1 | $ 7 | $ 165 |

| | Hedge funds | Private equity | Real estate | Total |
|---|---|---|---|---|
| **Pension Assets** | | | | |
| Balance as of January 1, 2010 | $— | $450 | $156 | $ 606 |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | 14 | 37 | 13 | 64 |
| Purchases, sales and settlements: | | | | |
| Purchases | 315 | 67 | 14 | 396 |
| Sales | — | — | (4) | (4) |
| Settlements | — | (18) | — | (18) |
| Transfers into (out of) Level 3 | — | — | — | — |
| Balance as of December 31, 2010 | $329 | $536 | $179 | $1,044 |
| **Other Postretirement Benefits** | | | | |
| Balance as of January 1, 2010 | $— | $— | $— | $ — |
| Actual return on plan assets: | | | | |
| Relating to assets still held at the reporting date | — | — | 2 | 2 |
| Purchases, sales and settlements: | | | | |
| Purchases | 5 | — | 2 | 7 |
| Sales | — | — | — | — |
| Settlements | — | — | — | — |
| Transfers into (out of) Level 3 [(a)] | — | — | 4 | 4 |
| Balance as of December 31, 2010 | $ 5 | $— | $ 8 | $ 13 |

(a) Commingled fund investments determined to be illiquid during the year were transferred into Level 3.

*Valuation Techniques Used to Determine Fair Value*

*Cash equivalents.* Investments with maturities of three months or less when purchased, including certain short-term fixed income securities and money market funds are considered cash equivalents and are included in the recurring fair value measurements hierarchy as Level 1.

*Equity securities.* With respect to individually held equity securities, including investments in U.S. and international securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Exelon is able to independently corroborate. Equity securities held individually are primarily traded on exchanges that contain only actively traded securities, due to the volume trading requirements imposed by these exchanges. Equity securities are valued based on quoted prices in active markets and are categorized as Level 1.

Equity commingled funds and mutual funds are maintained by investment companies that hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For equity commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2.

*Fixed income.* For fixed income securities, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Exelon has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon selectively corroborates the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly-liquid and transparent markets. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2. To draw parallels from the trading and quoting of fixed income securities with similar features, pricing services consider various characteristics including the issuer, maturity, purpose of loan, collateral attributes, prepayment speeds, interest rates and credit ratings in order to properly value these securities.

Fixed income commingled funds and mutual funds, including short-term investment funds, are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For fixed income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2.

*Private equity.* Private equity investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments and investments in natural resources. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows and market based comparable data. Since these valuation inputs are not highly observable, private equity investments have been categorized as Level 3.

*Hedge funds.* Hedge fund investments include those seeking to maximize absolute returns using a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is determined using net asset value per share (NAV) or ownership interest of the investments. Exelon has the ability to redeem these investments at NAV or its equivalent subject to certain restrictions which may include a lock-up period and a fund level gate. Since these restrictions may limit Exelon's ability to redeem the investments at the measurement date, the hedge fund investments are classified as Level 3.

*Real estate.* Real estate investment trusts valued daily based on quoted prices in active markets are categorized as Level 1. Real estate commingled funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Since these funds are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Other real estate funds are funds with a direct investment in a pool of real estate properties. These funds are valued by investment managers on a periodic basis using pricing models that use independent appraisals from sources with professional qualifications. Since these valuation inputs are not highly observable, real estate funds have been categorized as Level 3.

**Defined Contribution Savings Plan**

Exelon, Generation, ComEd and PECO participate in a 401(k) defined contribution savings plan sponsored by Exelon. The plan is qualified under applicable sections of the IRC and 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 following table presents matching contributions to the savings plan for the years ended December 31, 2011, 2010 and 2009:

| For the Year Ended December 31, | |
|---|---|
| 2011 | $78 |
| 2010 | 81 |
| 2009 | 70 |

## 14. Corporate Restructuring and Plant Retirements

Exelon provides severance and health and welfare benefits to terminated employees primarily based upon each individual employee's years of service and compensation level. Exelon accrues amounts associated with severance benefits that are considered probable and that can be reasonably estimated.

The following tables present severance benefits expenses, recorded as operating and maintenance expense in relation to the announced job reductions, for the years ended December 31, 2011, 2010 and 2009:

| For the Year Ended December 31, | |
|---|---|
| 2011 - Plant retirements | $ 4 |
| 2010 - Plant retirements | 4 |
| 2009 - Plant retirements | 7 |
| 2009 - Corporate restructuring [(a)] | 34 |

(a) Severance benefits include $4 million at Exelon of contractual termination benefits expense for which the obligation is recorded in other postretirement benefits.

***Corporate restructuring.*** In June 2009, Exelon announced a restructured senior executive team and major spending cuts, including the elimination of approximately 500 employee positions. Exelon eliminated approximately 400 corporate support positions, mostly located at corporate headquarters, and 100 management level positions at ComEd, the majority of which was completed by September 30, 2009. These actions were in response to the continuing economic challenges confronting all parts of Exelon's business and industry especially in light of the commodity-driven nature of Generation's markets, necessitating continued focus on cost management through enhanced efficiency and productivity.

Exelon recorded a pre-tax charge for estimated salary continuance and health and welfare severance benefits of $40 million in June 2009 as a result of the planned job reductions. Subsequent to June 2009, Exelon recorded a net pre-tax credit of approximately $6 million, which included a $10 million reduction in estimated salary continuance and health and welfare severance benefits, offset by $4 million of expense for contractual termination benefits. Cash payments under the plan began in July 2009 and were completed as of December 31, 2011.

The following table presents the activity of severance obligations for the corporate restructuring from January 1, 2010 through December 31, 2011, excluding obligations recorded in equity:

| Severance Benefits Obligation | |
|---|---|
| Balance at January 1, 2010 | $ 19 |
| Cash payments | (18) |
| Balance at December 31, 2010 | 1 |
| Cash payments | (1) |
| Balance at December 31, 2011 | $— |

***Plant Retirements.*** On December 8, 2010, in connection with the executed Administrative Consent Order (ACO) with the NJDEP, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. See Note 18 for additional information regarding the closure of Oyster Creek.

In 2009, Exelon announced its intention to permanently retire three coal-fired generating units and one oil/gas-fired generating unit, effective May 31, 2011, in response to the economic outlook related to the continued operation of these four units. However, PJM determined that transmission reliability upgrades would be necessary to alleviate reliability impacts and that those upgrades would be completed in a manner that will permit Generation's retirement of two of the units on that date and two of the units subsequent to May 31, 2011. On May 31, 2011, Cromby Generating Station (Cromby) Unit 1 and Eddystone Generating Station (Eddystone) Unit 1 were retired; Cromby Unit 2 retired on December 31, 2011 and Eddystone Unit 2 will retire on May 31, 2012. On May 27, 2011, the FERC approved a settlement providing for a reliability-must-run rate schedule, which defines compensation to be paid to Generation for continuing to operate these units. The monthly fixed-cost recovery during the reliability-must-run period for Eddystone Unit 2 is approximately $6 million. Such revenue is intended to recover total expected operating costs, plus a return on net assets, of the two units during the reliability-must-run period. In addition, Generation is reimbursed for variable costs, including fuel, emissions costs, chemicals, auxiliary power and for project investment costs during the reliability-must-run period. Eddystone Unit 2 and Cromby Unit 2 began operating under the reliability-must-run agreement effective June 1, 2011.

In connection with the retirement of all four units, Exelon is eliminating 253 employee positions, the majority of which are located at the units to be retired. Total expected costs for Generation related to the announced retirements is $37 million, which includes $14 million for estimated salary continuance and health and welfare severance benefits, a $17 million write down of inventory and $6 million of shut down costs. Cash payments under this plan began in January 2010 and will continue through 2013.

Since the announced retirements in December 2009, Generation recorded pre-tax expense of $32 million, which included a $13 million charge for estimated salary continuance and health and welfare severance benefits, $17 million of expense for the write down of inventory and $2 million of shut down costs recorded within operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations.

During the year ended December 31, 2011, Generation recorded pre-tax expense of $4 million for estimated salary continuance and health and welfare severance benefits and $2 million of shut down costs. During the year ended December 31, 2010, Generation recorded a net $3 million charge which is primarily due to an increase in estimated salary continuance and health and welfare severance benefits.

The following table presents the activity of severance obligations for the announced Cromby and Eddystone retirements from January 1, 2010 through December 31, 2011:

| Severance Benefits Obligation | |
|---|---|
| Balance at January 1, 2010 | $ 7 |
| Severance charges recorded | 4 |
| Cash payments | (1) |
| Other adjustments | (3) |
| Balance at December 31, 2010 | 7 |
| Severance charges recorded | 4 |
| Cash payments | (4) |
| Balance at December 31, 2011 | $ 7 |

## 15. Preferred Securities

At December 31, 2011 and 2010, Exelon was authorized to issue up to 100,000,000 shares of preferred securities, none of which were outstanding.

### Preferred and Preference Securities of Subsidiaries

At December 31, 2011 and 2010, ComEd prior preferred securities and ComEd cumulative preference securities consisted of 850,000 shares and 6,810,451 shares authorized, respectively, none of which were outstanding.

At December 31, 2011 and 2010, PECO cumulative preferred securities, no par value, consisted of 15,000,000 shares authorized and the outstanding amounts set forth below. Shares of preferred securities have full voting rights, including the right to cumulate votes in the election of directors.

| | Redemption Price [(a)] | December 31, 2011 | 2010 | 2011 | 2010 |
|---|---|---|---|---|---|
| | | Shares Outstanding | | Dollar Amount | |
| **Series (without mandatory redemption)** | | | | | |
| $4.68 (Series D) | $104.00 | 150,000 | 150,000 | $15 | $15 |
| $4.40 (Series C) | 112.50 | 274,720 | 274,720 | 27 | 27 |
| $4.30 (Series B) | 102.00 | 150,000 | 150,000 | 15 | 15 |
| $3.80 (Series A) | 106.00 | 300,000 | 300,000 | 30 | 30 |
| Total preferred securities | | 874,720 | 874,720 | $87 | $87 |

(a) Redeemable, at the option of PECO, at the indicated dollar amounts per share, plus accrued dividends.

## 16. Common Stock

At December 31, 2011 and 2010, Exelon's common stock without par value consisted of 2,000,000,000 shares authorized and 663,368,958 shares and 661,845,411, shares outstanding, respectively. At December 31, 2011 and 2010, ComEd's common stock with a $12.50 par value consisted of 250,000,000 shares authorized and 127,016,529 shares and 127,016,519 shares outstanding, respectively. At December 31, 2011 and 2010, PECO's common stock without par value consisted of 500,000,000 shares authorized and 170,478,507 shares outstanding.

ComEd had 75,096 and 75,139 warrants outstanding to purchase ComEd common stock at December 31, 2011 and 2010, 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, 2011 and 2010, 25,032 and 25,046 shares of common stock, respectively, were reserved for the conversion of warrants.

### Share Repurchases

*Share Repurchase Programs.* In April 2004, Exelon's Board of Directors approved a discretionary share repurchase program that allowed Exelon to repurchase shares of its common stock on a periodic basis in the open market. The share repurchase program was intended to mitigate, in part, the dilutive effect of shares issued under Exelon's employee stock option plan and Exelon's ESPP. The aggregate value of the shares of common stock repurchased pursuant to the program cannot exceed the economic benefit received after January 1, 2004 due to stock option exercises and share purchases pursuant to Exelon's ESPP. The economic benefit consists of the direct cash proceeds from purchases of stock and the tax benefits associated with exercises of stock options. The 2004 share repurchase program had no specified limit on the number of shares that could be repurchased and no specified termination date. Any shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon's management.

In the third quarter of 2008, Exelon's Board of Directors approved a share repurchase program for $1.5 billion of its common stock. Subsequently, Exelon's management determined to defer indefinitely any share repurchases. This decision was made in light of a variety of factors, including: developments affecting the world economy and commodity markets, including those for electricity and gas; the continued uncertainty in capital and credit markets and the potential impact of those events on Exelon's future cash needs; projected cash needs to support investment in the business, including maintenance capital and nuclear uprates; and value-added growth opportunities.

Under the share repurchase programs dating back to 2004, 34.7 million shares of common stock are held as treasury stock with a cost of $2.3 billion at December 31, 2011. During 2011, 2010 and 2009, Exelon had no common stock repurchases.

### Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes performance share awards, stock options and restricted stock units. At December 31, 2011, there were approximately 24 million shares authorized for issuance under the LTIP. For the years ended December 31, 2011, 2010 and 2009, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

As the LTIP sponsor, Exelon is the sole issuer of all stock-based compensation awards. All awards are recorded as equity or a liability in Exelon's Consolidated Balance Sheets. The stock-based compensation expense specifically attributable to the employees of Generation, ComEd and PECO is directly recorded to operating and maintenance expense within each of their respective Consolidated Statements of Operations. Stock-based compensation expense attributable to BSC employees is allocated to the Registrants using a cost-causative allocation method.

The following table presents the stock-based compensation expense included in Exelon's Consolidated Statements of Operations for the years ended December 31, 2011, 2010 and 2009:

| | Year Ended December 31, | | |
|---|---|---|---|
| **Components of Stock-Based Compensation Expense** | **2011** | **2010** | **2009** |
| Performance share awards | $ 26 | $ 6 | $ 31 |
| Stock options | 8 | 10 | 20 |
| Restricted stock units | 31 | 21 | 26 |
| Other stock-based awards | 4 | 4 | 4 |
| Total stock-based compensation expense included in operating and maintenance expense | 69 | 41 | 81 |
| Income tax benefit | (27) | (16) | (32) |
| Total after-tax stock-based compensation expense | $ 42 | $ 25 | $ 49 |

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2011, 2010 and 2009.

Exelon receives a tax deduction based on the intrinsic value of the award on the exercise date for stock options and distribution date for performance share awards and restricted stock units. For each award, throughout the requisite service period, Exelon recognizes the tax benefit related to compensation costs. The tax deductions in excess of the benefits recorded throughout the requisite service period are recorded to common stock and are included in other financing activities within Exelon's Consolidated Statements of Cash Flows. The following table presents information regarding Exelon's tax benefits for the years ended December 31, 2011, 2010 and 2009:

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2011** | **2010** | **2009** |
| Realized tax benefit when exercised/distributed: | | | |
| Stock options | $2 | $ 5 | $ 6 |
| Restricted stock units | 8 | 9 | 7 |
| Performance share awards | 7 | 13 | 19 |
| Stock deferral plan | 1 | 1 | 1 |
| Excess tax benefits included in other financing activities of Exelon's Consolidated Statements of Cash Flows: | | | |
| Stock options | $1 | $ 3 | $ 4 |

*Stock Options*

Non-qualified stock options to purchase shares of Exelon's common stock are granted under the LTIP. The exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. Stock options granted under the LTIP generally become exercisable upon a specified vesting date. The vesting period of stock options is generally four years. All stock options expire ten years from the date of grant.

The value of stock options at the date of grant is expensed over the requisite service period using the straight-line method. The requisite service period for stock options is generally four years. However, certain stock options become fully vested upon the employee reaching retirement-eligibility. The value of the stock options granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility.

Exelon grants most of its stock options in the first quarter of each year. Stock options granted during the remaining quarters of 2011, 2010 and 2009 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, 2011, 2010 and 2009:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Dividend yield | 4.84% | 4.56% | 3.72% |
| Expected volatility | 24.40% | 27.10% | 36.70% |
| Risk-free interest rate | 2.65% | 2.96% | 2.01% |
| Expected life (years) | 6.25 | 6.25 | 6.25 |
| Weighted average grant date fair value (per share) | $ 6.22 | $ 8.08 | $14.43 |

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 for the year ended December 31, 2011:

| | Shares | Weighted Average Exercise Price (per share) | Weighted Average Remaining Contractual Life (years) | Aggregate Intrinsic Value |
|---|---|---|---|---|
| Balance of shares outstanding at December 31, 2010 | 11,209,003 | $48.39 | | |
| Options granted | 1,017,000 | 43.40 | | |
| Options exercised | (424,228) | 30.25 | | |
| Options forfeited | (68,175) | 49.82 | | |
| Options expired | (179,839) | 55.68 | | |
| Balance of shares outstanding at December 31, 2011 | 11,553,761 | $48.49 | 4.64 | $30 |
| Exercisable at December 31, 2011 [(a)] | 10,676,711 | $48.48 | 4.34 | $30 |

(a) Includes stock options issued to retirement eligible employees.

The following table summarizes additional information regarding stock options exercised for the years ended December 31, 2011, 2010 and 2009:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Intrinsic value [(a)] | $ 5 | $13 | $15 |
| Cash received for exercise price | 13 | 24 | 20 |

(a) The difference between the market value on the date of exercise and the option exercise price.

The following table summarizes Exelon's nonvested stock option activity for the year ended December 31, 2011:

| | Shares | Weighted Average Exercise Price (per share) |
|---|---|---|
| Nonvested at December 31, 2010 [(a)] | 942,525 | $54.35 |
| Granted [(b)] | 1,017,000 | 43.40 |
| Vested [(b)] | (902,636) | 47.27 |
| Forfeited | (179,839) | 55.68 |
| Nonvested at December 31, 2011 [(a)] | 877,050 | $48.66 |

(a) Excludes 1,348,000 and 1,209,225 of stock options issued to retirement-eligible employees as of December 31, 2011 and December 31, 2010, respectively, as they are fully vested.

(b) Includes 620,800 of stock options issued to retirement-eligible employees in 2011 that vested immediately upon the employee reaching retirement eligibility.

At December 31, 2011, $3 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 2.09 years.

*Restricted Stock Units*

Exelon grants restricted stock units under the LTIP. The majority of Exelon's restricted stock units will be settled in common stock. In accordance with the authoritative guidance for share-based payments, the cost of services received from employees in exchange for the issuance of restricted stock units to be settled in stock is required to be measured based on the grant date fair value of the restricted stock unit issued. On a very limited basis, Exelon has granted restricted stock units to certain ComEd executives that will be settled in cash. The obligations related to these restricted stock units have been classified as liabilities on Exelon's Consolidated Balance Sheets and are remeasured each reporting period throughout the requisite service period.

The value of the restricted stock units is expensed over the requisite service period using the straight-line method. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility. The value of the restricted stock units granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following table summarizes Exelon's nonvested restricted stock unit activity for the year ended December 31, 2011:

| | Shares | Weighted Average Grant Date Fair Value (per share) |
|---|---|---|
| Nonvested at December 31, 2010 [(a)] | 791,820 | $57.95 |
| Granted | 1,015,706 | 43.33 |
| Vested | (337,970) | 60.22 |
| Forfeited | (53,099) | 53.16 |
| Undistributed vested awards [(b)] | (341,973) | 44.03 |
| Nonvested at December 31, 2011 [(a)] | 1,074,484 | $48.08 |

(a) Excludes 448,827 and 233,794 of restricted stock units issued to retirement-eligible employees as of December 31, 2011 and December 31, 2010, respectively, as they are fully vested.

(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2011.

The weighted average grant date fair value (per share) of restricted stock units granted for the years ended December 31, 2011, 2010 and 2009 was $43.33, $44.23 and $56.08, respectively. At December 31, 2011 and 2010, Exelon had obligations related to outstanding restricted stock units not yet settled of $46 million and $38 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, 2011 and 2010, which are included in deferred credits and other liabilities in Exelon's

Consolidated Balance Sheets. For the years ended December 31, 2011, 2010 and 2009, Exelon settled restricted stock units with fair value totaling $19 million, $22 million and $17 million, respectively. At December 31, 2011, $26 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.12 years.

*Performance Share Awards*

Exelon grants performance share awards under the LTIP. In 2011, the number of performance shares granted was determined based on the measurement of Exelon's operating performance against a set of pre-defined strategic goals through the end of the year of grant. The 2011 performance share awards will be settled entirely in stock over the three year vesting term. These performance share awards 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 these equity classified performance share awards was estimated based on the expected payout of the award, which may range from 75% to 125% of the payout target. The portion of the award pertaining to the 75% payout floor is valued based on Exelon's stock price on the grant date. The expected payout in excess of the 75% floor is remeasured each reporting period based on Exelon's current stock price and changes in the expected payout of the award; therefore this portion of the award is subject to volatility until the payout is established.

In 2010 and 2009, the number of performance shares granted was 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 these 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.

The 2010 and 2009 performance share awards that were settled in stock were recorded as common stock within the Consolidated Balance Sheets and recorded at fair value at the date of grant. The grant date fair value of equity classified performance share awards granted during the years ended December 31, 2010 and 2009 was estimated using historical data for the previous two plan years and a Monte Carlo simulation model for the current plan year. This model requires assumptions regarding Exelon's total shareholder return relative to certain stock market indices and the stock beta and volatility of Exelon's common stock and all stocks represented in these indices. Volatility for Exelon and all comparable companies is based on historical volatility over one year using daily stock price observation. The 2010 and 2009 performance share awards that were settled in cash were recorded as liabilities within the Consolidated Balance Sheets. The grant date fair value of liability classified performance share awards granted during the years ended December 31, 2010 and 2009 was based on historical data for the previous two plan years and actual results for the current plan year. The liabilities were remeasured each reporting period throughout the requisite service period and as a result, the compensation costs for cash-settled awards were subject to volatility.

For non retirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method, a method in which the compensation cost is recognized over the requisite service period for each separately vesting tranche of the award as though the award were multiple awards. For performance shares granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period which is the year of grant.

The following table summarizes Exelon's nonvested performance share awards activity for the year ended December 31, 2011:

| | Shares | Weighted Average Grant Date Fair Value (per share) |
|---|---|---|
| Nonvested at December 31, 2010 (a) | 214,823 | $63.51 |
| Granted | 689,997 | 43.52 |
| Vested | (155,132) | 66.47 |
| Forfeited | (14,914) | 46.01 |
| Undistributed vested awards (b) | (387,926) | 43.66 |
| Nonvested at December 31, 2011 (a) | 346,848 | $45.37 |

(a) Excludes 455,418 and 234,419 of performance share awards issued to retirement-eligible employees as of December 31, 2011 and December 31, 2010, respectively, as they are fully vested.

(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2011.

The weighted average grant date fair value (per share) of performance share awards granted during the years ended December 31, 2011, 2010 and 2009 was $43.52, $60.82 and $57.34, respectively. During the years ended December 31, 2011, 2010 and 2009, Exelon settled performance shares with a fair value totaling $22 million, $32 million and $47 million, respectively, of which $10 million, $20 million and $30 million was paid in cash, respectively. As of December 31, 2011, $5 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 2 years.

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

| | December 31, | |
|---|---|---|
| | 2011 | 2010 |
| Current liabilities [(a)] | $ 3 | $ 9 |
| Deferred credits and other liabilities [(b)] | — | 4 |
| Common stock | 30 | 16 |
| Total | $ 33 | $29 |

(a) Represents the current liability related to performance share awards expected to be settled in cash.
(b) Represents the long-term liability related to performance share awards expected to be settled in cash.

## 17. Earnings Per Share and Equity

### *Earnings per Share*

Diluted earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding, including shares to be issued upon exercise of stock options, performance share awards and restricted stock outstanding under Exelon's LTIPs considered to be common stock equivalents. The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock on the weighted average number of shares outstanding used in calculating diluted earnings per share:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Net income | $2,495 | $2,563 | $2,707 |
| Weighted average common shares outstanding—basic | 663 | 661 | 659 |
| Assumed exercise and/or distributions of stock-based awards | 2 | 2 | 3 |
| Weighted average common shares outstanding—diluted | 665 | 663 | 662 |

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 9 million in 2011, 8 million in 2010 and 5 million in 2009.

## 18. Commitments and Contingencies

### Nuclear Insurance

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of December 31, 2011, the current liability limit per incident was $12.6 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once every 5 years and the last inflation adjustment was made effective October 29, 2008. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. As of January 1, 2012, the amount of nuclear energy liability insurance purchased is $375 million for each operating site. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory participation in a retrospective rating plan for power reactors (currently 104 reactors) resulting in an additional $12.2 billion in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Under the Price-Anderson Act, the maximum assessment in the event of an incident for each nuclear operator, per reactor, per incident (including a 5% surcharge), is $117.5 million, payable at no more than $17.5 million per reactor per incident per year. Exelon's maximum liability per incident is approximately $2.0 billion. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $12.6 billion limit for a single incident.

Generation is required each year to report to the NRC the current levels and sources of insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all. No distributions were declared in 2011. Premiums paid to NEIL by its members are subject to assessment (the retrospective premium obligation) for adverse loss experience. NEIL has never exercised this assessment since its formation in 1973, and while Generation cannot predict the level of future assessments, or if they will be imposed at all, the current maximum aggregate annual retrospective premium obligation for Generation is approximately $219 million.

NEIL provides property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. Generation's current limit for this coverage is $2.1 billion. For property limits in excess of the first $1.25 billion of that limit, Generation participates in an $850 million single limit blanket policy shared by all the Generation operating nuclear sites and the Salem and Hope Creek nuclear sites. This blanket limit is not subject to automatic reinstatement in the event of a loss. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, 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 $175 million per year for losses incurred at any plant insured by the insurance company (the retrospective premium obligation). In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery for all losses by all insureds will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses. The $3.2 billion maximum recovery limit is not applicable, however, in the event of a "certified act of terrorism" as defined in the Terrorism Risk Insurance Act of 2002, as amended by the Terrorism Risk Insurance Program Reauthorization Act of 2007. The Terrorism Risk Insurance Act expires on December 31, 2014.

Additionally, NEIL provides replacement power cost insurance in the event of a major accidental outage at an insured nuclear station. The premium for this coverage is subject to assessment for adverse loss experience. Generation's maximum share of any assessment is $44 million per year (the retrospective premium obligation). Recovery under this insurance for terrorist acts is subject to the $3.2 billion aggregate limit and secondary to the property insurance described above. This limit would not apply in cases of certified acts of terrorism under the Terrorism Risk Insurance Act of 2002, as amended by the Terrorism Risk Insurance Program Reauthorization Act of 2007, as described above.

Effective April 1, 2009, NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

In addition, Generation participates in the Master Worker Program, which provides coverage for worker tort claims filed for bodily injury caused by a nuclear energy accident. This program was modified, effective January 1, 1998, to provide coverage to all workers whose "nuclear-related employment" began on or after the commencement date of reactor operations. Generation will not be liable for a retrospective assessment under this policy.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon's and Generation's financial condition, results of operations and liquidity.

**Spent Nuclear Fuel Obligation**

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from Generation's nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation pays the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance will be delayed significantly. In January 2009, the DOE issued its Draft National Transportation Plan for the proposed repository. The DOE's press statement accompanying the release of the plan indicated that shipments to the repository are not expected to begin before 2020.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository while the Obama administration devises a new strategy for long-term SNF management. Debate surrounding any new strategy likely will address centralized interim storage, permanent storage at multiple sites and/or SNF reprocessing. In early 2010, Secretary of Energy Steven Chu appointed the Blue Ribbon Commission on America's Nuclear Future to evaluate and recommend a new plan for managing the back end of the nuclear fuel cycle, including used fuel storage, disposal and fees. John W. Rowe, Exelon's Chairman and Chief Executive Officer, is one of 15 members of the Commission. The Commission released its final report to the U.S. Energy Secretary on January 26, 2012, detailing comprehensive recommendations for creating a safe, long-term solution for managing and disposing of the nation's spent nuclear fuel and high-level radioactive waste. The strategy recommended by the Commission encompasses 8 key elements; 1) A new consent-based approach to siting storage and disposal facilities; 2) A new organization to implement the waste management program; 3) Access to utility waste disposal fees for their intended purpose; 4) Prompt efforts to develop a new geological disposal facility; 5) Prompt efforts to develop one or more consolidated storage facilities; 6) Early preparation for the eventual large-scale transport of spent nuclear fuel and high-level waste to consolidated storage and disposal facilities; 7) Support for advances in nuclear energy technology and for workforce development; and 8) Active U.S. leadership in international efforts to address safety, non-proliferation and security concerns. Implementation of the BRC's recommendations will require action by both the Administration and Congress.

Given the full implementation of the BRC's recommendations will require action by both the Administration and Congress, it is uncertain whether interim storage facilities or permanent disposal facilities will be operational by 2020. Because there is no particular date before or after 2020 that Generation can establish as having a higher probability as the start date for facility operations, Generation uses the 2020 date as the assumed date for when the DOE will begin accepting SNF for purposes of determining nuclear decommissioning asset retirement obligations. The extended delay in SNF acceptance by the DOE has led to Generation's adoption of dry cask storage at its Dresden, Limerick, Oyster Creek, Peach Bottom, Byron, Braidwood, LaSalle and Quad Cities stations. Generation performed sensitivity analyses assuming that the estimated date for the DOE acceptance of SNF was delayed to 2025 and to 2035 and determined that Generation's aggregate nuclear ARO would be increased by approximately $150 million and $250 million, respectively. In August 2004, Generation and the DOJ, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse Generation, subject to certain damage limitations based on the extent of the government's breach, for costs associated with storage of SNF at Generation's nuclear stations pending the DOE's fulfillment of its obligations. Generation submits annual reimbursement requests to the DOE for costs associated with the storage of SNF. In all cases, reimbursement requests are made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

Under the settlement agreement, Generation has received cash reimbursements for costs incurred through April 30, 2011, totaling approximately $562 million ($473 million after considering amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek). As of December 31, 2011, the amount of SNF storage costs for which reimbursement will be requested from the DOE under the settlement agreement is $54 million, which is recorded within accounts receivable, other. Of this amount, $4 million represents amounts owed to the co-owners of the Peach Bottom and Quad Cities generating facilities.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The fee related to the former PECO units has been paid. Pursuant to the Standard Contracts, ComEd previously elected to defer payment of the one-time fee of $277 million for its units (which are now part of Generation), with interest to the date of payment, until just prior to the first delivery of SNF to the DOE. As of December 31, 2011, the unfunded SNF liability for the one-time fee with interest was $1,019 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, 2011, was 0.025%. The liabilities for SNF disposal costs, including the one-time fee, were transferred to Generation as part of the 2001 corporate restructuring. The outstanding one-time fee obligations for the Oyster Creek and TMI units remain with the former owners. Clinton has no outstanding obligation. See Note 8—Fair Value of Assets and Liabilities for additional information.

**Energy Commitments**

Generation's wholesale operations include the physical delivery and marketing of power obtained through its generation capacity, and long-, intermediate- and short-term contracts. Generation maintains a net positive supply of energy and capacity, through ownership of generation assets and power purchase and lease agreements, to protect it from the potential operational failure of one of its owned or contracted power generating units. Generation has also contracted for access to additional generation through bilateral long-term PPAs. These agreements are firm commitments related to power generation of specific generation plants and/or are dispatchable in nature. Several of Generation's long-term PPAs, which have been determined to be operating leases, have significant contingent rental payments that are dependent on the future operating characteristics of the associated plants, such as plant availability. Generation recognizes contingent rental expense when it becomes probable of payment. Generation enters into PPAs with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to its customers. Generation has also purchased firm transmission rights to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs. The primary intent and business objective for the use of its capital assets and contracts is to provide Generation with physical power supply to enable it to deliver energy to meet customer needs. Generation primarily uses financial contracts in its wholesale marketing activities for hedging purposes. Generation also uses financial contracts to manage the risk surrounding trading for profit activities.

Generation has entered into bilateral long-term contractual obligations for sales of energy to load-serving entities, including electric utilities, municipalities, electric cooperatives and retail load aggregators. Generation also enters into contractual obligations to deliver energy to wholesale market participants who primarily focus on the resale of energy products for delivery. Generation provides delivery of its energy to these customers through rights for firm transmission.

At December 31, 2011, Generation's short- and long-term commitments, relating to the purchase from and sale to unaffiliated utilities and others of energy, capacity and transmission rights, are as indicated in the following tables:

| | Net Capacity Purchases (a) | Power Only Purchases (b) | Power Only Sales | Transmission Rights Purchases (c) |
|---|---|---|---|---|
| 2012 | $177 | $ 11 | $1,150 | $ 9 |
| 2013 | 71 | — | 834 | 6 |
| 2014 | 63 | — | 346 | — |
| 2015 | 61 | — | 200 | — |
| 2016 | 61 | — | 177 | — |
| Thereafter | 478 | — | 737 | — |
| Total | $911 | $ 11 | $3,444 | $ 15 |

(a) Net capacity purchases include PPAs and other capacity contracts that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at December 31, 2011. Expected payments include certain capacity charges which are contingent on plant availability.

(b) Excludes renewable energy PPA contracts that are contingent in nature.

(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

Pursuant to a PPA with Public Service Company of Oklahoma, a subsidiary of American Electric Power Company, Inc., dated as of April 17, 2009, Generation agreed to sell its rights to up to 520 MWs, or approximately two-thirds of the capacity, energy and ancillary services supplied under its existing long-term contract with Green Country Energy, LLC. The delivery of power under the PPA is to commence June 1, 2012 and run through February 28, 2022.

ComEd purchases its expected energy requirements through an ICC approved competitive bidding process administered by the IPA, existing ICC approved RFPs, and spot market purchases hedged with a financial swap contract with Generation expiring in 2013. See Note 2—Regulatory Matters for further information.

PECO's long-term PPA with Generation, under which PECO obtained all of its electric supply from Generation over the past 12 years, expired on December 31, 2010. During 2009, 2010 and 2011, PECO entered into contracts through a competitive procurement process in order to meet a portion of its default service customers' electric supply requirements for 2011 through 2015. See Note 2—Regulatory Matters for further information regarding the DSP Program.

ComEd is subject to requirements established by the Illinois Settlement Legislation and the Energy Infrastructure Modernization Act related to the use of alternative energy resources. PECO is subject to requirements related to the use of alternative energy resources and electric consumption reductions established by the AEPS Act and Act 129, respectively. PECO has entered into contracts with curtailment service providers as part of its EE&C plan in attempt to comply with electric load reduction targets in the top 100 peak hours, during the summer months of June 2012 through September 2012. See Note 2—Regulatory Matters for additional information relating to electric generation procurement, alternative energy resources and energy efficiency programs.

ComEd's and PECO's electric supply procurement, curtailment services and REC and AEC purchase commitments as of December 31, 2011 are as follows:

| | | Expiration within | | | | | |
|---|---|---|---|---|---|---|---|
| | Total | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 and beyond |
| ComEd | | | | | | | |
| Electric supply procurement | $ 678 | $207 | $292 | $179 | $— | $— | $ — |
| RECs | 1 | 1 | — | — | — | — | — |
| Long-term renewable energy and associated RECs [a] | 1,692 | 36 | 70 | 72 | 73 | 80 | 1,361 |
| PECO | | | | | | | |
| Electric supply procurement | 1,088 | 760 | 244 | 59 | 25 | — | — |
| AECs | 39 | 7 | 11 | 9 | 2 | 2 | 8 |
| Curtailment services | 13 | 13 | — | — | — | — | — |

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

**Fuel Purchase Obligations**

In addition to the energy commitments described above, Generation has commitments to purchase fuel supplies for nuclear and fossil generation (and with respect to coal, commitments to sell coal) and PECO has commitments to purchase natural gas, related transportation, storage capacity and services to serve customers in their gas distribution service territory. As of December 31, 2011, these net commitments were as follows:

| | | Expiration within | | | | | |
|---|---|---|---|---|---|---|---|
| | Total | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 and beyond |
| Generation | $8,211 | $1,317 | $925 | $1,010 | $1,066 | $717 | $3,176 |
| PECO | 511 | 174 | 86 | 71 | 53 | 34 | 93 |

**Commercial Commitments**

Exelon's commercial commitments as of December 31, 2011, representing commitments potentially triggered by future events, were as follows:

| | | Expiration within | | | | | |
|---|---|---|---|---|---|---|---|
| | Total | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 and beyond |
| Letters of credit (non-debt) [a] | $ 952 | $267 | $— | $— | $685 | $— | $ — |
| Surety bonds [b] | 74 | 10 | — | — | 1 | 6 | 57 |
| Performance guarantees [c] | 533 | 135 | 96 | 200 | — | — | 102 |
| Energy marketing contract guarantees [d] | 280 | 216 | 31 | 3 | — | — | 30 |
| Nuclear insurance premiums [e] | 2,217 | — | — | — | — | — | 2,217 |
| Lease guarantees [f] | 55 | — | 3 | — | — | — | 52 |
| 2007 City of Chicago Settlement [g] | 2 | 2 | — | — | — | — | — |
| Midwest Generation Capacity Reservation Agreement guarantee [h] | 2 | 2 | — | — | — | — | — |
| Total commercial commitments | $4,115 | $632 | $130 | $203 | $686 | $ 6 | $2,458 |

(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, 2011, guarantees of $1 million have been issued to provide support for certain letters of credit as required by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantees—Guarantees issued to ensure performance under specific contracts.
(d) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts.
(e) Nuclear insurance premiums—Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.
(f) Lease guarantees—Guarantees issued to ensure payments on building leases.
(g) 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 $53 million was paid through December 31, 2011.
(h) 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.

Exelon's commercial commitments shown above as of December 31, 2011 do not reflect the package of benefits of more than $1 billion proposed as part of the application for approval of the merger. See Note 3—Merger and Acquisitions for additional information on the proposed merger with Constellation.

### Construction Commitments

Generation has committed to the construction of a solar PV facility in Los Angeles County, California. Generation's estimated commitments are $539 million and $374 million for the years 2012 and 2013, respectively. See Note 3—Merger and Acquisitions for additional information.

Refer to Note 2—Regulatory Matters for information on investment programs associated with regulatory mandates such as ComEd's Infrastructure Investment Plan under EIMA and PECO's Smart Meter Procurement and Installation Plan.

### 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, 2011 were:

| | |
|---|---|
| 2012 | $ 65 |
| 2013 | 59 |
| 2014 | 56 |
| 2015 | 45 |
| 2016 | 47 |
| Remaining years | 387 |
| Total minimum future lease payments | $659[a][b] |

(a) Excludes Generation's PPAs and other capacity contracts that are accounted for as contingent operating lease payments.
(b) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, Exelon has excluded these payments from the Remaining years, as such amounts would not be meaningful. Exelon's annual obligation for these agreements, included in each of the years 2012—2013, was $3 million, and in the years 2014 – 2016 was $4 million.

The following table presents Exelon's rental expense under operating leases for the years ended December 31, 2011, 2010 and 2009:

| For the Year Ended December 31, | |
|---|---|
| 2011 | $711[a] |
| 2010 | 722[a] |
| 2009 | 691[a] |

(a) Includes Generation's PPAs and other capacity contracts that are accounted for as operating leases and are reflected as net capacity purchases in the energy commitments table above. These agreements are considered contingent operating lease payments and are not included in the minimum future operating lease payments table above. Payments made under Generation's PPAs and other capacity contracts totaled $630 million, $641 million and $616 million during 2011, 2010 and 2009, respectively.

For information regarding capital lease obligations, see Note 10—Debt and Credit Agreements.

**Indemnifications Related to Sale of 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. The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy was approximately $200 million at December 31, 2011.

**Indemnifications Related to Sale of TEG and TEP**

On February 9, 2007, Tamuin International Inc. (TII), a wholly owned subsidiary of Generation, sold its 49.5% ownership interests in TEG and TEP to a subsidiary of AES Corporation for $95 million in cash plus certain purchase price adjustments. In connection with the transaction, Generation entered into a guarantee agreement under which Generation guarantees the timely payment of TII's obligations to the subsidiary of AES Corporation pursuant to the terms of the purchase and sale agreement relating to the sale of TII's ownership interests. Generation would be required to perform in the event that TII does not pay any obligation covered by the guarantee that is not otherwise subject to a dispute resolution process. Generation's maximum obligation under the guarantee is $95 million. Generation has not recorded a liability associated with this guarantee. The exposures covered by this guarantee expired in part during 2008. Generation expects that the remaining exposure will expire by 2014.

**Environmental Matters**

***General.*** Exelon's 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, Exelon is 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. Exelon owns or leases a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, Exelon is currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

ComEd and PECO have identified 42 and 27 sites, respectively, where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, ComEd or PECO is one of several PRPs that may be responsible for ultimate remediation of each location. Of the 42 sites identified by ComEd, the Illinois EPA or U.S. EPA have approved the cleanup of 13 sites and of the 27 sites identified by PECO, the PA DEP has approved the cleanup of 16 sites. Of the remaining sites identified by ComEd and PECO, 27 and 11 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 2016 and 2019, respectively.

Pursuant to orders from the ICC and PAPUC, respectively, ComEd and PECO are authorized to and are currently recovering environmental costs for the remediation of former MGP facility sites from customers, for which they have recorded regulatory assets. During the third quarter of 2011, ComEd and PECO each completed an annual study of their future estimated MGP remediation requirements. The results of these studies indicated that additional remediation would be required at certain sites; accordingly, ComEd and PECO increased their reserves and regulatory assets by $14 million and $7 million, respectively. See Note 2—Regulatory Matters for additional information regarding the associated regulatory assets.

As of December 31, 2011 and 2010, Exelon has accrued the following undiscounted amounts for environmental liabilities in other deferred credits and other liabilities within its Consolidated Balance Sheets:

| | Total environmental investigation and remediation reserve | Portion of total related to MGP investigation and remediation |
|---|---|---|
| 2011 | $224 | $168 |
| 2010 | 179 | 156 |

Exelon cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by Exelon's environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

***Water***

***Section 316(b) of the Clean Water Act.*** Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected. Those facilities are Clinton, Cromby, Dresden, Eddystone, Fairless Hills, Handley, Mountain Creek, Oyster Creek, Peach Bottom, Quad Cities, Salem and Schuylkill.

On March 28, 2011, the EPA issued the proposed regulation under Section 316(b). The proposal does not require closed-cycle cooling (e.g., cooling towers) as the best technology available to address impingement and entrainment. The proposal provides the state permitting agency with discretion to determine the best technology available to limit entrainment (drawing aquatic life into the plants cooling system) mortality, including application of a cost-benefit test and the consideration of a number of site-specific factors. After consideration of these factors, the state permitting agency may require closed cycle cooling, an alternate technology, or determine that the current technology is the best available. The rule also imposes limits on impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or similar technology at the intake. Exelon filed comments on the proposed regulation on August 18, 2011, stating its support for a number of its provisions (e.g., cooling towers not required as best technology available, and the use of site-specific and cost benefit analysis) while also noting a number of technical provisions that require revision to take into account existing unit operations and practices within the industry. Pursuant to a court approved Settlement Agreement, the EPA is required to approve the final rule by July 27, 2012. Until the rule is finalized, the state permitting agencies will continue to apply their best professional judgment to address impingement and entrainment.

***Oyster Creek.*** On January 7, 2010, the NJDEP issued a draft NPDES permit for Oyster Creek that would have required, in the exercise of its best professional judgment, the installation of cooling towers as the best technology available within seven years after the effective date of the permit. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek no later than December 31, 2019. The current NRC license for Oyster Creek expires in 2029. In reliance upon Exelon's determination to cease generation operations no later than December 31, 2019, the NJDEP determined that closed cycle cooling is not the best technology available for Oyster Creek given the length of time that would be required to retrofit from the existing once-through cooling system to a closed-cycle cooling system and the limited life span of the plant after installation of a closed-cycle cooling system. Based on its consideration of these and other factors, NJDEP determined that the existing measures at the plant represent the best technology available for the facility's cooling water intake through cessation of generation operations.

On December 9, 2010, Generation executed an Administrative Consent Order (ACO) with the NJDEP regarding Oyster Creek. The ACO sets forth, among other things, the agreement by Generation to permanently cease generation operations at Oyster Creek if the conditions of the ACO are satisfied. In accordance with the ACO, on December 21, 2011, the NJDEP issued a final NPDES permit to be effective on April 12, 2012 that does not require the construction of cooling towers or other closed-cycle cooling facilities. The ACO and the final permit apply only to Oyster Creek based on its unique circumstances and does not set any precedent for the ultimate compliance requirements for Section 316(b) at Exelon's other plants.

As a result of the decision and the ACO, the expected economic useful life of Oyster Creek was reduced by 10 years to correspond to Exelon's current best estimate as to timing of ceasing generation operations at the Oyster Creek unit in 2019. The financial impacts relate primarily to accelerated depreciation and accretion expense associated with the changes in decommissioning assumptions related to Generation's asset retirement obligation over the remaining expected economic useful life of Oyster Creek.

***Salem and Other Power Generation Facilities.*** In June 2001, the NJDEP issued a renewed NPDES permit for Salem, allowing for the continued operation of Salem with its existing cooling water system. NJDEP advised PSEG in July 2004 that it strongly recommended reducing cooling water intake flow commensurate with closed-cycle cooling as a compliance option for Salem. PSEG submitted an application for a renewal of the permit on February 1, 2006. In the permit renewal application, PSEG analyzed closed-cycle cooling and other options and demonstrated that the continuation of the Estuary Enhancement Program, an extensive environmental restoration program at Salem, is the best technology to meet the Section 316(b) requirements. PSEG continues to operate Salem under the approved June 2001 NPDES permit while the NPDES permit renewal application is being reviewed. If the final permit or Section 316(b) regulations ultimately requires the retrofitting of Salem's cooling water intake structure to reduce cooling water intake flow commensurate with closed-cycle cooling, Exelon's and Generation's share of the total cost of the retrofit and any resulting interim replacement power would likely be in excess of $430 million, based on a 2006 estimate, and would result in increased depreciation expense related to the retrofit investment.

It is unknown at this time whether the NJDEP permit programs will require closed-cycle cooling at Salem. In addition, the economic viability of Generation's other power generation facilities without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Should the final rule not require the installation of cooling towers, and retain the flexibility afforded the state permitting agencies in applying a cost-benefit test and to consider site-specific factors, the impact of the rule would be minimized even though the costs of compliance could be material to Generation.

Given the uncertainties associated with the requirements that will be contained in the final rule, Generation cannot predict the eventual outcome or estimate the effect that compliance with any resulting Section 316(b) or interim state requirements will have on the operation of its generating facilities and its future results of operations, cash flows and financial position.

***Alleged Conemaugh Clean Streams Violation by PA DEP.*** The PA DEP has alleged that GenOn Northeast Management Company, the operator of Conemaugh Generating Station (CGS), violated the Clean Streams Law. GenOn is engaged in discussions with PA DEP and the Company anticipates that the parties will reach a settlement pursuant to which GenOn will be obligated to pay a civil penalty of $500,000, of which Generation's responsibility would be approximately $100,000.

***Conemaugh Station Water Discharge Violations.*** In April 2007, two environmental groups brought a Clean Water Act citizen suit against the operator of CGS, seeking civil penalties and injunctive relief for alleged violations of CGS's NPDES permit. On March 21, 2011, the court entered a partial summary judgment in the plaintiffs' favor, declaring as a matter of law that discharges from CGS had violated the NPDES permit. On June 6, 2011, the operator of CGS signed and entered with the court a settlement and consent decree with the plaintiffs. Under the consent decree, CGS will pay a total of $5 million, of which Generation's share is $1 million.

***Air***

***Cross-State Air Pollution Rule.*** On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the CAIR, which had been promulgated by the U.S. EPA to reduce power plant emissions of $SO_2$ and $NO_x$. The D.C. Circuit Court later remanded the CAIR to the U.S. EPA, without invalidating the entire rulemaking, so that the U.S. EPA could correct CAIR in accordance with the D.C. Circuit Court's July 11, 2008 opinion. On July 6, 2010, the U.S. EPA published the proposed Transport Rule as the replacement to the CAIR. On July 7, 2011, the U.S. EPA published the final rule, now known as the Cross-State Air Pollution Rule (CSAPR). The CSAPR requires 27 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states. The final rule maintains the January 1, 2012 and January 1, 2014 phase-in dates that were in the proposed Transport Rule. However, the CSAPR imposes tighter emissions caps than the proposed Transport Rule and includes six additional states under the summertime $NO_x$ reduction requirements. These emissions limits may be further reduced as the U.S. EPA finalizes more restrictive ozone and particulate matter NAAQS in the 2012-2013 timeframe.

Under the CSAPR, Generation units will receive allowances based on historic heat input. Intrastate, and limited interstate, trading of allowances is permitted, subject to certain limitations. The CSAPR restricts entirely the use of pre-2012 allowances. Existing $SO_2$ allowances under the ARP would remain available for use under ARP. During the third quarter of 2010, Generation recognized a lower of cost or market impairment charge of $57 million on its ARP $SO_2$ allowances that are not expected to be used by Generation's fossil-fuel power plants and that have not been sold forward. The impairment was recorded due to the significant decline of allowance market prices because CSAPR regulations would restrict entirely the use of ARP $SO_2$ allowances beginning in 2012. As of December 31, 2011, Generation had $4 million of emission allowances carried at the lower of weighted average cost or market. Numerous entities have challenged the CSAPR in the D.C. Circuit Court, and some have requested a stay of the rule pending the D.C. Circuit Court's consideration of the matter on the merits. Exelon believes that the CSAPR is a valid exercise of the

U.S. EPA's authority and discretion under the Clean Air Act. The D.C. Circuit Court has granted permission for Exelon, as well as a number of other parties, to intervene in the litigation in support of the rule and in opposition to a stay of the rule. The D.C. Circuit Court has not set a case management schedule, and it is therefore unknown when the litigation will be resolved.

On October 14, 2011, the EPA proposed for public comment certain technical corrections to CSAPR, including correction of data errors in determining generation unit allowances and state allowance budgets. These corrections will increase the number of emission allowances available under the CSAPR. In addition, the proposal defers until 2014 penalties that will involve surrender of additional allowances should states not meet certain levels of emission reductions. This deferral is intended to increase the liquidity of allowances during the initial years of transition from CAIR to CSAPR.

Numerous entities challenged the CSAPR in the D.C. Circuit Court, and some requested a stay of the rule pending the Court's consideration of the matter on the merits. On December 30, 2011, the Court granted a stay of the CSAPR, and directed the U.S. EPA to continue the administration of CAIR in the interim. Subsequently the Court ordered an expedited briefing schedule that requires that final briefs be submitted by March 16, 2012, and scheduled oral argument for April 13, 2012. It is unknown when the Court will issue its decision on the merits. Exelon believes that the CSAPR is a valid exercise of the U.S. EPA's authority and discretion under the Clean Air Act. The D.C. Circuit Court has granted permission for Exelon, as well as a number of other parties, to intervene in the litigation in support of the rule.

***EPA Mercury and Air Toxics Standards (MATS).*** In March 2005, the U.S. EPA finalized the CAMR, which was a national program to cap mercury emissions from fossil-fuel-fired electric utility steam generating units (EGUs) starting in 2010, with a second reduction in the mercury emission cap level scheduled for 2018. The D.C. Circuit Court later vacated the CAMR on the basis that the U.S. EPA had failed to properly de-list mercury as a HAP under Section 112(c)(1) of the Clean Air Act. The result of this decision is that mercury emissions from EGUs are subject to the more stringent requirements of maximum achievable control technology applicable to HAPs. In resolution of the CAMR litigation, the U.S. EPA entered into a Consent Decree that required it to propose by March 16, 2011 HAP regulations for emissions from fossil generating stations, and to publish final HAP regulations by November 15, 2011.

On December 16, 2011, the U.S. EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the new source performance standards for EGUs. The final rule, known as the Mercury and Air Toxics (MATS) rule, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals from air emissions. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that smaller, older, uncontrolled coal units will retire rather than make these investments. Coal units with existing controls that do not meet the required standards may need to upgrade existing controls or add new controls to comply. In addition, the new standards will cause oil units to achieve high removal rates of metals. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies or retire the units. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, with specific guidelines for an additional one or two years in limited cases. The rule will be effective 60 days after it is published in the Federal Register in early 2012. Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS by January 1, 2015.

The U.S. EPA previously announced that it would complete a review of NAAQS in the 2011 – 2012 timeframe for particulate matter, nitrogen dioxide, sulfur dioxide, and lead. This review could result in more stringent emissions limits on fossil-fired electric generating stations. In September 2011, the U.S. EPA withdrew its reconsideration of the NAAQS standard for ozone, which is next scheduled for reconsideration in 2013.

In addition, as of December 31, 2011, Exelon has a $656 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases extending through 2028-2032. While Exelon currently estimates the value of these plants at the end of the lease term will be in excess of the recorded residual lease values, final applications of the CSAPR and HAP regulations could negatively impact the end-of-lease term values of these assets, which could result in a future impairment loss that could be material.

***Notices and Finding of Violations Related to Electric Generation Stations.*** On August 6, 2007, ComEd received a NOV, addressed to it and Midwest Generation, LLC (Midwest Generation) from the U.S. EPA, alleging that ComEd and Midwest Generation have violated and are continuing to violate several provisions of the Clean Air Act as a result of the modification and/or operation of six electric generation stations located in northern Illinois that have been owned and operated by Midwest Generation since 1999.

The generating stations are currently owned and operated by Midwest Generation, which purchased the stations in December 1999 from ComEd. Under the terms of the sale agreement, Midwest Generation and its affiliate, Edison Mission Energy (EME), assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance of the stations with environmental laws before the purchase of the stations by Midwest Generation. Midwest Generation and EME additionally agreed to indemnify and hold ComEd and its affiliates harmless from claims, fines, penalties, liabilities and expenses arising from third party claims against ComEd resulting from or arising out of the environmental liabilities assumed by Midwest Generation and EME under the terms of the agreement governing the sale.

In August 2009, the DOJ and the Illinois Attorney General filed a complaint against Midwest Generation with the U.S. District Court for the Northern District of Illinois initiating enforcement proceedings with respect to the alleged Clean Air Act violations set forth in the NOV. Neither ComEd nor Exelon were named as a defendant in this original complaint. In March 2010, the District Court granted Midwest Generation's partial motion to dismiss all but one of the claims against Midwest Generation. The Court held that Midwest Generation cannot be liable for any alleged violations relating to construction that occurred prior to Midwest Generation's ownership of the stations. In May 2010, the government plaintiffs filed an amended complaint substantially similar to the original complaint, and added ComEd and EME as defendants. The amended complaint seeks injunctive relief and civil penalties against all defendants, although not all of the claims specifically pertain to ComEd. On March 16, 2011, the U.S. District Court granted ComEd's motion to dismiss the May 2010 complaint. On January 3, 2012, upon leave of the U.S. District Court, the government parties appealed the dismissal of ComEd to the U.S. Circuit Court of Appeals.

In connection with Exelon's 2001 corporate restructuring, Generation assumed ComEd's rights and obligations with respect to its former generation business. Exelon, Generation and ComEd are unable to predict the ultimate resolution of the claims alleged in the amended complaint, the costs that might be incurred or the amount of indemnity that may be available from Midwest Generation and EME; however, Exelon, Generation and ComEd have concluded that in light of the District Court's decision the likelihood of loss is remote. Therefore, no reserve has been established. Further, Generation believes that it would be reimbursed by Midwest Generation and EME for any losses under the terms of the indemnification agreement, subject to the credit worthiness of Midwest Generation and EME.

***Solid and Hazardous Waste***

***Cotter Corporation.*** The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Bridgeton, Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. The current estimated cost of the anticipated landfill cover remediation for the site is approximately $42 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the EPA for review. It is anticipated that the EPA will propose a remedy in the first quarter of 2012, which will be subject to public comment. Thereafter the EPA will select a final remedy and enter into a Consent Decree with the PRP's to effectuate the remedy. An excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require the use of an excavation remedy is remote.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U. S. government's Manhattan Project. Cotter purchased the residues in 1967 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $100 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2012 so that settlement discussions could proceed. Based on Exelon's preliminary review, it appears probable that Exelon has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

***Climate Change Regulation.*** Exelon is subject to climate change regulation or legislation at the international, Federal, regional and state levels. In 2007, the U.S. Supreme Court ruled that GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. Consequently, on December 7, 2009, the U.S. EPA issued an endangerment finding under Section 202 of the Clean Air Act regarding GHGs from new motor vehicles and on April 1, 2010 issued final regulations limiting GHG emissions from cars and light trucks effective on January 2, 2011. While such regulations do not specifically address stationary sources, such as a generating plant, it is the U.S. EPA's position that the regulation of GHGs under the mobile source provisions of the Clean Air Act has triggered the permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources effective January 2, 2011. Therefore, on May 13, 2010, the U.S. EPA issued final regulations relating to these provisions of the Clean Air Act for major stationary sources of GHG emissions that apply to new sources that emit greater than 100,000 tons per year, on a $CO_2$ equivalent basis, and to modifications to existing sources that result in emissions increases greater than 75,000 tons per year on a $CO_2$ equivalent basis. These thresholds became effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. Under the regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case-by-case basis. Exelon could be significantly affected by the regulations if it were to build new plants or modify existing plants.

**Litigation and Regulatory Matters**

***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. Legal costs are charged to operating and maintenance expense as incurred.

At December 31, 2011 and 2010, Generation had reserved approximately $49 million and $53 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2011, approximately $14 million of this amount related to 180 open claims presented to Generation, while the remaining $35 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050 based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary. During 2011, 2010 and 2009, the updates to this reserve did not result in material adjustments.

***Savings Plan Claim.*** On September 11, 2006, five individuals claiming to be participants in the Exelon Corporation Employee Savings Plan, Plan #003 (Savings Plan), filed a putative class action lawsuit in the U.S. District Court for the Northern District of Illinois. The complaint names as defendants Exelon, its Director of Employee Benefit Plans and Programs, the Employee Savings Plan Investment Committee, the Compensation and the Risk Oversight Committees of Exelon's Board of Directors and members of those committees. On December 9, 2009, the District Court granted the defendants' motion to dismiss the amended complaint and enter judgment in favor of the defendants. The plaintiffs appealed the District Court's dismissal of their claims to the U.S. Court of Appeals for the Seventh Circuit who affirmed the dismissal of the class action lawsuit on September 6, 2011.

***General.*** Exelon is involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Exelon maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

**Fund Transfer Restrictions**

Under applicable law, Exelon may borrow or receive an extension of credit from its subsidiaries. Under the terms of Exelon's intercompany money pool agreement, Exelon can lend to, but not borrow from the money pool.

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

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

PECO's Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. At December 31, 2011, such capital was $2.9 billion and amounted to about 34 times the liquidating value of the outstanding preferred securities of $87 million. Additionally, PECO may not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures, which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued.

**Continuous Power Interruption**

Illinois law provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) 30,000 or more customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law. ComEd does not believe that during the years 2011, 2010 and 2009 it had any interruptions that have triggered this damage liability or reimbursement requirement.

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable under provisions of the Illinois Public Utilities Act that could require damage compensation to customers in connection with the July 11, 2011 storm system that affected more than 900,000 customers in ComEd's service territory, as well as five other storm systems that affected ComEd's customers during June and July 2011. The ICC is currently conducting a proceeding to assess ComEd's request. In the absence of a favorable determination from the ICC, some ComEd customers affected by the outages could seek recovery of their actual, non-consequential damages, and the local governments in which those customers are located could seek recovery of emergency and contingency expenses. On January 27, 2012, the ICC Staff and the Illinois Attorney General filed testimony in the ICC proceeding. They both disagree with ComEd's interpretation that the statute does not apply to the 2011 storms. Additionally, the ICC witness supports granting a waiver for three of the six storms, while the Attorney General asserts that ComEd should be held responsible for the damages from all of the storms. ComEd is continuing to assess its position relative to its request and is scheduled to file responsive testimony during the first quarter of 2012. The ultimate outcome of this proceeding is uncertain, and the amount of damages, if any, that might be asserted cannot be reasonably estimated at this time, but may be material to ComEd's results of operations and cash flows. Additional active proceedings related to storms of lesser collective impact are also pending.

**Income Taxes**

See Note 11—Income Taxes for information regarding Exelon's 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, 2011, 2010 and 2009.

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| **Operating revenues** [(a)] | | | |
| Wholesale | $ 7,717 | $ 5,934 | $ 5,469 |
| Retail electric and gas [(b)] | 10,323 | 11,906 | 11,099 |
| Other [(c)] | 884 | 804 | 750 |
| Total operating revenues | $18,924 | $18,644 | $17,318 |

(a) Includes operating revenues from affiliates.

(b) Generation's retail electric and gas operating revenues consist primarily of Exelon Energy Company, LLC. Generation's retail electric operating revenues are allocated among its reportable segments.

(c) Includes amounts recorded related to the Illinois Settlement Legislation.

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| **Depreciation, amortization and accretion** | | | |
| Property, plant and equipment | $1,284 | $1,144 | $ 996 |
| Regulatory assets [(a)] | 51 | 931 | 838 |
| Nuclear fuel [(b)] | 755 | 672 | 558 |
| ARO accretion [(c)] | 214 | 196 | 209 |
| Total depreciation, amortization and accretion | $2,304 | $2,943 | $2,601 |

(a) Primarily reflects CTC amortization expense at PECO.

(b) Included in fuel expense on Exelon's Consolidated Statements of Operations.

(c) Included in operating and maintenance expense on Exelon's Consolidated Statements of Operations.

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| **Taxes other than income** | | | |
| Utility [(a)] | $443 | $476 | $481 |
| Real estate | 177 | 175 | 157 |
| Payroll | 123 | 121 | 114 |
| Other | 42 | 36 | 26 |
| Total taxes other than income | $785 | $808 | $778 |

(a) Generation's utility tax represents gross receipts tax related to its retail operations and ComEd's and PECO's utility taxes represent municipal and state utility taxes and gross receipts taxes related to their operating revenues, respectively. The offsetting collection of utility taxes from customers is recorded in revenues on Exelon's Consolidated Statements of Operations.

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| **Loss in equity method investments** | | | |
| NuStart Energy Development, LLC | $ (1) | $— | $ (3) |
| Financing trusts | — | — | (24) |
| Total loss in equity method investments | $ (1) | $— | $(27) |

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| **Other, Net** | | | |
| Decommissioning-related activities: | | | |
| Net realized income on decommissioning trust funds [(a)]— | | | |
| Regulatory Agreement Units | $ 177 | $ 176 | $ 126 |
| Non-Regulatory Agreement Units | 45 | 51 | 29 |
| Net unrealized (losses) gains on decommissioning trust funds— | | | |
| Regulatory Agreement Units | (74) | 316 | 801 |
| Non-Regulatory Agreement Units | (4) | 104 | 227 |
| Net unrealized gains on pledged assets— | | | |
| Zion Station decommissioning | 48 | — | — |
| Regulatory offset to decommissioning trust fund-related activities [(b)] | (130) | (394) | (746) |
| Total decommissioning-related activities | 62 | 253 | 437 |
| Investment income | 10 | 1 | 5 |
| Long-term lease income | 28 | 27 | 26 |
| Interest income related to uncertain income tax positions [(c)] | 53 | — | 50 |
| AFUDC-Equity | 17 | 11 | 9 |
| Bargain purchase gain related to Wolf Hollow acquisition | 36 | — | — |
| Realized gain on Rabbi trust investments | — | 1 | 5 |
| Other-than-temporary impairment to Rabbi trust investments [(d)] | — | — | (7) |
| Losses on early retirement of debt | — | — | (117) |
| Other | (7) | 19 | 19 |
| Other, net | $ 199 | $ 312 | $ 427 |

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.

(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 12—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(c) Primarily includes interest income at ComEd from the 2009 re-measurement of income tax uncertainties. See Note 11—Income Taxes for additional information.

(d) ComEd recorded an other-than-temporary impairment to Rabbi trust investments during 2009.

***Supplemental Cash Flow Information***

The following tables provide additional information regarding Exelon's Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009.

| For the Year Ended December 31, 2011 | |
|---|---|
| **Cash paid (refunded) during the year:** | |
| Interest (net of amount capitalized) | $ 649 |
| Income taxes (net of refunds) | (457) |
| **Other non-cash operating activities:** | |
| Pension and non-pension postretirement benefit costs | $ 542 |
| Provision for uncollectible accounts | 121 |
| Stock-based compensation costs | 67 |
| Other decommissioning-related activity [(a)] | 16 |
| Energy-related options [(b)] | 137 |
| Amortization of regulatory asset related to debt costs | 21 |
| Uncollectible accounts recovery, net | 14 |
| Discrete impacts from 2010 Rate Case order [(c)] | (32) |
| Bargain purchase gain related to Wolf Hollow Acquisition | (36) |
| Discrete impacts from Energy Infrastructure Modernization Act (EIMA) [(d)] | (82) |
| Other | 14 |
| Total other non-cash operating activities | $ 782 |
| **Changes in other assets and liabilities:** | |
| Under/over-recovered energy and transmission costs | $ (45) |
| Other current assets | (101) |
| Other noncurrent assets and liabilities | 126 |
| Total changes in other assets and liabilities | $ (20) |
| **Non-cash investing and financing activities:** | |
| Change in ARC | $ 186 |
| Change in capital expenditures not paid | 96[(e)] |

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 12—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(b) Includes amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of underlying transactions.

(c) In May 2011, as a result of the 2010 Rate Case order, ComEd recorded one-time benefits to reestablish previously expensed plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan. See Note 2—Regulatory Matters for more information.

(d) Includes the establishment of a regulatory asset, pursuant to EIMA, for the 2011 annual reconciliation in ComEd's distribution formula rate tariff and the deferral of costs associated with significant 2011 storms, partially offset by an accrual to fund a new Science and Technology Innovation Trust. See Note 2—Regulatory Matters for more information.

(e) Includes $120 million of capital expenditures not paid as of December 31, 2011 related to Antelope Valley.

| For the Year Ended December 31, 2010 | |
|---|---|
| **Cash paid (refunded) during the year:** | |
| Interest (net of amount capitalized) | $ 665[a] |
| Income taxes (net of refunds) | 1,219 |
| **Other non-cash operating activities:** | |
| Pension and non-pension postretirement benefit costs | $ 581 |
| Provision for uncollectible accounts | 108 |
| Provision for obsolete inventory | 12 |
| Stock-based compensation costs | 44 |
| Other decommissioning-related activity [b] | (91) |
| Energy-related options [c] | (73) |
| ARO adjustment | (19) |
| Amortization of regulatory asset related to debt costs | 24 |
| Accrual for Illinois utility distribution tax refund [d] | (25) |
| Under-recovered uncollectible accounts, net [e] | (14) |
| ARP SO2 allowances impairment | 57 |
| Other | 5 |
| Total other non-cash operating activities | $ 609 |
| **Changes in other assets and liabilities:** | |
| Under/over-recovered energy and transmission costs | $ 61 |
| Other current assets | (18) |
| Other noncurrent assets and liabilities | (99) |
| Total changes in other assets and liabilities | $ (56) |
| **Non-cash investing and financing activities:** | |
| Change in ARC | $ (428) |
| Change in capital expenditures not paid | 34 |
| Purchase accounting adjustments | 9 |
| Exelon Wind acquisition [f] | 32 |

(a) Excludes $167 million of interest paid to the IRS relating to a preliminary agreement reached during the third quarter of 2010. See Note 11—Income Taxes for addition information.

(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 12—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(c) Includes amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of underlying transactions.

(d) During the second quarter of 2010, ComEd recorded a reduction of $25 million to taxes other than income to reflect management's estimate of future refunds for the 2008 and 2009 tax years associated with Illinois' utility distribution tax based on an analysis of past refunds and interpretations of the Illinois Public Utility Act. Historically, ComEd has recorded refunds of the Illinois utility distribution tax when received. ComEd believes it now has sufficient, reliable evidence to record and support an estimated receivable associated with the anticipated refund for the 2008 and 2009 tax years.

(e) Includes $70 million of under-recovered uncollectible accounts expense from 2008 and 2009 recorded in the first quarter of 2010 as well as $59 million of amortization of the associated regulatory asset. This amount also includes a credit of $3 million of undercollections associated with 2010 activity. ComEd is recovering these costs through a rider mechanism authorized by the ICC. See Note 2—Regulatory Matters for additional information regarding the Illinois legislation for recovery of uncollectible accounts.

(f) Represents contingent liability recorded in connection with the December 9, 2010 acquisition of Exelon Wind. See Note 3—Acquisition for additional information.

| For the Year Ended December 31, 2009 | |
|---|---|
| **Cash paid (refunded) during the year:** | |
| Interest (net of amount capitalized) | $ 647 |
| Income taxes (net of refunds) | 982 |
| **Other non-cash operating activities:** | |
| Pension and non-pension postretirement benefit costs | $ 536 |
| Loss in equity method investments | 27 |
| Provision for uncollectible accounts | 149 |
| Stock-based compensation costs | 70 |
| Other decommissioning-related activity (a) | (163) |
| Energy-related options (b) | 46 |
| ARO adjustment (c) | (47) |
| Amortization of regulatory liability related to debt costs | 25 |
| Amortization of the regulatory liability related to the PURTA tax settlement | (2) |
| Other-than-temporary impairment to Rabbi trust impairments (d) | 7 |
| Inventory write-down related to plant retirements | 17 |
| Other | (13) |
| Total other non-cash operating activities | $ 652 |
| **Changes in other assets and liabilities:** | |
| Under/over-recovered energy and transmission costs | $ 23 |
| Other current assets | (2) |
| Other noncurrent assets and liabilities | (134)(e) |
| Total changes in other assets and liabilities | $(113) |
| **Non-cash investing and financing activities:** | |
| Change in ARC | $ 67 |
| Change in capital expenditures not paid | 70 |
| Purchase accounting adjustments | 9 |

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 12—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(b) Includes amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of underlying transactions.

(c) Represents the reduction in the ARO in excess of the existing ARC balances for Generation's nuclear generating units that are not subject to regulatory agreement with respect to decommissioning trust funding (the former AmerGen units and the portions of the Peach Bottom units).

(d) ComEd recorded an other-than-temporary impairment to Rabbi trust investments during the second quarter of 2009. See Note 8—Fair Value of Assets and Liabilities for additional information regarding the impairment.

(e) Relates primarily to a decrease in interest payable associated with the remeasurement of uncertain income tax positions. See Note 11—Income Taxes for additional information.

*DOE Smart Grid Investment Grant.* For the years ended December 31, 2011 and December 31, 2010, Exelon and PECO have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $51 million and $28 million, respectively, and reimbursements of $56 million in 2011 related to PECO's DOE SGIG. See Note 2—Regulatory Matters for additional information regarding the accounting for the DOE SGIG.

***Supplemental Balance Sheet Information***

The following tables provide additional information about Exelon's assets and liabilities at December 31, 2011 and 2010.

| | December 31, 2011 | December 31, 2010 |
|---|---|---|
| **Investments** | | |
| Equity method investments: | | |
| Financing trusts [(a)] | $ 15 | $ 15 |
| Keystone Fuels, LLC | 13 | 10 |
| Conemaugh Fuels, LLC | 16 | 13 |
| Sacramento Solar | 1 | — |
| NuStart Energy Development, LLC | — | 1 |
| Total equity method investments | 45 | 39 |
| Other investments: | | |
| Net investment in direct financing leases | 656 | 629 |
| Employee benefit trusts and investments [(b)] | 65 | 64 |
| Total investments | $766 | $732 |

(a) Includes investments in financing trusts, which were not consolidated within the financial statements of Exelon. See Note 1—Significant Accounting Policies for additional information.

(b) Exelon's investments in these marketable securities are recorded at fair market value.

*December 2010 IRS Payment.* In the third quarter of 2010, Exelon and IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions. In order to stop additional interest from accruing on the expected assessment resulting from the agreement, Exelon paid $302 million to the IRS on December 28, 2010. As of December 31, 2010, Exelon had not funded the specific bank account from which the IRS payment was disbursed resulting in a current liability. This amount was subsequently funded in January 2011. Under the authoritative guidance for offsetting balances, Exelon included this payment in Cash and cash equivalents with an offsetting amount in Other current liabilities on its Consolidated Balance Sheets. See Note 11—Income Taxes for additional information.

*Like-Kind Exchange Transaction.* Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in passive generating station leases with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. For financial accounting purposes, the investments are accounted for as direct financing lease investments. UII holds the leasehold interests in the generating stations in several separate bankruptcy remote, special purpose companies it directly or indirectly wholly owns. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to require the lessees to return the leasehold interests or to arrange a service contract with a third party for a period following the lease term. If Exelon chooses the service contract option, the leasehold interests will be returned to Exelon at the end of the term of the service contract. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. In the fourth quarter of 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases. At December 31, 2011 and 2010, the components of the net investment in long-term leases were as follows:

| | December 31, 2011 | December 31, 2010 |
|---|---|---|
| Estimated residual value of leased assets | $1,492 | $1,492 |
| Less: unearned income | 836 | 863 |
| Net investment in long-term leases | $ 656 | $ 629 |

The following tables provide additional information about Exelon's liabilities at December 31, 2011 and 2010.

| | December 31, 2011 | December 31, 2010 |
|---|---|---|
| **Accrued expenses** | | |
| Compensation-related accruals [(a)] | $ 520 | $ 465 |
| Taxes accrued | 297 | 297 |
| Interest accrued | 192 | 195 |
| Severance accrued | 15 | 22 |
| Other accrued expenses | 231[(b)] | 61 |
| Total accrued expenses | $1,255 | $1,040 |

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.
(b) Includes $184 million for amounts accrued related to Antelope Valley.

The following tables provide information about accumulated OCI (loss) recorded (after tax) within Exelon's Consolidated Balance Sheets at December 31, 2011 and 2010:

| | December 31, 2011 | December 31, 2010 |
|---|---|---|
| **Accumulated other comprehensive income (loss)** | | |
| Net unrealized gain on cash flow hedges | $ 488 | $ 400 |
| Pension and non-pension postretirement benefit plans | (2,938) | (2,823) |
| Unrealized loss on marketable securities | — | — |
| Total accumulated other comprehensive income (loss) | $(2,450) | $(2,423) |

## 20. Segment Information

Exelon has five reportable segments, which include Generation's three reportable segments consisting of the Mid-Atlantic, Midwest, and South and West, and ComEd and PECO.

Mid-Atlantic represents Generation's operations primarily in Pennsylvania, New Jersey and Maryland; Midwest includes the operations in Illinois, Indiana, Michigan and Minnesota; and the South and West includes operations primarily in Texas, Georgia, Oklahoma, Kansas, Missouri, Idaho and Oregon. Generation's retail gas, proprietary trading, other revenues and mark-to-market activities have not been allocated to a segment.

Exelon and Generation evaluate the performance of Generation's power marketing activities in Mid-Atlantic, Midwest, and South and West based on revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement of operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd and PECO. Purchased power costs include all costs associated with the procurement of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for internally generated energy and fuel costs associated with tolling agreements. Generation's retail gas, proprietary trading, compensation under the reliability-must-run rate schedule, other revenues and mark-to-market activities are not allocated to a region. Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

ComEd and PECO each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon evaluates the performance of ComEd and PECO based on net income.

An analysis and reconciliation of Exelon's reportable segment information to the respective information in the consolidated financial statements follows:

| | Generation (a) | ComEd | PECO | Other | Intersegment Eliminations | Consolidated |
|---|---|---|---|---|---|---|
| **Operating revenues** (b): | | | | | | |
| 2011 | $10,308 | $ 6,056 | $3,720 | $ 830 | $ (1,990) | $18,924 |
| 2010 | 10,025 | 6,204 | 5,519 | 755 | (3,859) | 18,644 |
| 2009 | 9,703 | 5,774 | 5,311 | 757 | (4,227) | 17,318 |
| **Intersegment revenues** (c): | | | | | | |
| 2011 | $ 1,161 | $ 2 | $ 5 | $ 831 | $ (1,990) | $ 9 |
| 2010 | 3,102 | 2 | 5 | 756 | (3,859) | 6 |
| 2009 | 3,472 | 2 | 6 | 756 | (4,227) | 9 |
| **Depreciation and amortization** | | | | | | |
| 2011 | $ 570 | $ 542 | $ 202 | $ 21 | $ — | $ 1,335 |
| 2010 | 474 | 516 | 1,060 | 25 | — | 2,075 |
| 2009 | 333 | 494 | 952 | 55 | — | 1,834 |
| **Operating expenses** (b): | | | | | | |
| 2011 | $ 7,432 | $ 5,074 | $3,065 | $ 863 | $ (1,990) | $14,444 |
| 2010 | 6,979 | 5,148 | 4,858 | 792 | (3,859) | 13,918 |
| 2009 | 6,408 | 4,931 | 4,614 | 840 | (4,225) | 12,568 |
| **Interest expense, net:** | | | | | | |
| 2011 | $ 170 | $ 345 | $ 134 | $ 77 | $ — | $ 726 |
| 2010 | 153 | 386 | 193 | 85 | — | 817 |
| 2009 | 113 | 319 | 187 | 112 | — | 731 |
| **Income (loss) before income taxes:** | | | | | | |
| 2011 | $ 2,827 | $ 666 | $ 535 | $ (63) | $ (13) | $ 3,952 |
| 2010 | 3,150 | 694 | 476 | (91) | (8) | 4,221 |
| 2009 | 3,555 | 603 | 499 | (235) | (3) | 4,419 |
| **Income taxes:** | | | | | | |
| 2011 | $ 1,056 | $ 250 | $ 146 | $ 9 | $ (4) | $ 1,457 |
| 2010 | 1,178 | 357 | 152 | (27) | (2) | 1,658 |
| 2009 | 1,433 | 229 | 146 | (102) | 6 | 1,712 |
| **Net income (loss):** | | | | | | |
| 2011 | $ 1,771 | $ 416 | $ 389 | $ (72) | $ (9) | $ 2,495 |
| 2010 | 1,972 | 337 | 324 | (64) | (6) | 2,563 |
| 2009 | 2,122 | 374 | 353 | (133) | (9) | 2,707 |
| **Capital expenditures:** | | | | | | |
| 2011 | $ 2,491 | $ 1,028 | $ 481 | $ 42 | $ — | $ 4,042 |
| 2010 | 1,883 | 962 | 545 | 14 | (78)(d) | 3,326 |
| 2009 | 1,977 | 854 | 388 | 54 | — | 3,273 |
| **Total assets:** | | | | | | |
| 2011 | $27,433 | $22,653 | $9,156 | $6,244 | $(10,394) | $55,092 |
| 2010 | 24,534 | 21,652 | 8,985 | 6,651 | (9,582) | 52,240 |

(a) Generation represents the three segments, Mid-Atlantic, Midwest, and South and West as shown below. Intersegment revenues for the years ended December 31, 2011, 2010 and 2009 represent Mid-Atlantic revenue from sales to PECO of $508 million, $2,092 million and $2,016 million, respectively, and Midwest revenue from sales to ComEd of $653 million, $1,010 million and $1,456 million, respectively.

(b) For the years ended December 31, 2011, 2010 and 2009, utility taxes of $243 million, $205 million and $232 million, respectively, are included in revenues and expenses for ComEd. For the years ended December 31, 2011, 2010 and 2009, utility taxes of $173 million, $271 million and $249 million, respectively, are included in revenues and expenses for PECO.

(c) The intersegment profit associated with Generation's sale of AECs to PECO is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. See Note 2—Regulatory Matters for additional information on AECs. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations.

(d) Represents capital projects transferred from BSC to Generation, ComEd and PECO. These projects are shown as capital expenditures at Generation, ComEd and PECO and the capital expenditure is eliminated upon consolidation.

| | Mid-Atlantic | Midwest | South and West | Other [b] | Generation |
|---|---|---|---|---|---|
| **Total revenues [a]:** | | | | | |
| 2011 | $3,967 | $5,344 | $ 776 | $ 221 | $10,308 |
| 2010 | 3,246 | 5,762 | 692 | 325 | 10,025 |
| 2009 | 3,195 | 5,538 | 714 | 256 | 9,703 |
| **Revenues net of purchased power and fuel expense:** | | | | | |
| 2011 | $3,359 | $3,547 | $ 70 | $(118) | $ 6,858 |
| 2010 [c] | 2,512 | 4,081 | (131) | 100 | 6,562 |
| 2009 | 2,578 | 4,148 | (117) | 162 | 6,771 |

(a) Includes all sales to third parties and affiliated sales to ComEd and PECO. For the years ended December 31, 2011, 2010 and 2009, there were no transactions among Generation's reportable segments which would result in intersegment revenue for Generation.

(b) Includes retail gas, proprietary trading, other revenue and mark-to-market activities as well as amounts paid related to the Illinois Settlement Legislation.

(c) In 2010, Other also includes the $57 million lower of cost or market impairment for the ARP $SO_2$ allowances further described in Note 18—Commitments and Contingencies.

## 21. Related Party Transactions

The financial statements of Exelon include related party transactions as presented in the tables below:

| | For the Years Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Operating revenues from affiliates: | | | |
| PETT [(a)] | $— | $— | $ 3 |
| PECO [(b)] | 9 | 6 | 9 |
| Total operating revenues from affiliates | $ 9 | $ 6 | $ 12 |
| Fuel purchases from related parties: | | | |
| Keystone Fuels, LLC | $ 68 | $ 74 | $ 56 |
| Conemaugh Fuels, LLC | 69 | 70 | 69 |
| Total fuel purchases from related parties | $137 | $144 | $125 |
| Charitable contribution to Exelon Foundation [(c)] | $— | $ 10 | $ 10 |
| Interest expense to affiliates, net: | | | |
| ComEd Financing III | $ 13 | $ 13 | $ 13 |
| PETT [(a)] | — | — | 51 |
| PECO Trust III | 6 | 6 | 6 |
| PECO Trust IV | 6 | 6 | 6 |
| Other | — | — | 1 |
| Total interest expense to affiliates, net | $ 25 | $ 25 | $ 77 |
| Loss in equity method investments: | | | |
| PETT [(a)] | $— | $— | $ (24) |
| NuStart Energy Development, LLC | (1) | — | (3) |
| Total loss in equity method investments | $ (1) | $— | $ (27) |

| | December 31, | |
|---|---|---|
| | 2011 | 2010 |
| Investments in affiliates: | | |
| ComEd Financing III | $ 6 | $ 6 |
| PECO Energy Capital Corporation | 4 | 4 |
| PECO Trust IV | 5 | 5 |
| Total investments in affiliates | $ 15 | $ 15 |
| Payables to affiliates (current): | | |
| ComEd Financing III | $ 4 | $ 4 |
| PECO Trust III | 1 | 1 |
| Total payables to affiliates (current) | $ 5 | $ 5 |
| Long-term debt to financing trusts (including due within one year): | | |
| ComEd Financing III | $206 | $206 |
| PECO Trust III | 81 | 81 |
| PECO Trust IV | 103 | 103 |
| Total long-term debt due to financing trusts | $390 | $390 |

(a) PETT was consolidated in Exelon's financial statements on January 1, 2010 pursuant to authoritative guidance relating to the consolidation of VIEs. See Note 1—Significant Accounting Policies for additional information. PETT was liquidated and dissolved upon repayment of the debt in September 2010.

(b) The intersegment profit associated with Generation's sale of AECs to PECO is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. See Note 2—Regulatory Matters for additional information.

(c) Exelon Foundation is a nonconsolidated not-for-profit Illinois corporation. The Exelon Foundation was established in 2007 to serve educational and environmental philanthropic purposes and does not serve a direct business or political purpose of Exelon.

## 22. Quarterly Data (Unaudited)

The data shown below, which may not equal the total for the year due to the effects of rounding and dilution, includes all adjustments that Exelon considers necessary for a fair presentation of such amounts:

| | Operating Revenues | | Operating Income | | Net Income | |
|---|---|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 | 2011 | 2010 |
| Quarter ended: | | | | | | |
| March 31 | $5,052 | $4,461 | $1,202 | $1,402 | $668 | $749 |
| June 30 | 4,587 | 4,398 | 1,034 | 1,018 | 620 | 445 |
| September 30 | 5,295 | 5,291 | 1,181 | 1,367 | 601 | 845 |
| December 31 | 3,991 | 4,494 | 1,062 | 939 | 606 | 524 |

| | Average Basic Shares Outstanding (in millions) | | Net Income per Basic Share | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Quarter ended: | | | | |
| March 31 | 662 | 661 | $1.01 | $1.13 |
| June 30 | 663 | 661 | 0.93 | 0.67 |
| September 30 | 663 | 662 | 0.91 | 1.28 |
| December 31 | 664 | 662 | 0.91 | 0.79 |

| | Average Diluted Shares Outstanding (in millions) | | Net Income per Diluted Share | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Quarter ended: | | | | |
| March 31 | 664 | 662 | $1.01 | $1.13 |
| June 30 | 664 | 662 | 0.93 | 0.67 |
| September 30 | 665 | 663 | 0.90 | 1.27 |
| December 31 | 666 | 663 | 0.91 | 0.79 |

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

| | 2011 | | | | 2010 | | | |
|---|---|---|---|---|---|---|---|---|
| | Fourth Quarter | Third Quarter | Second Quarter | First Quarter | Fourth Quarter | Third Quarter | Second Quarter | First Quarter |
| High price | $45.45 | $45.27 | $42.89 | $43.58 | $44.49 | $43.32 | $45.10 | $49.88 |
| Low price | 39.93 | 39.51 | 39.53 | 39.06 | 39.05 | 37.63 | 37.24 | 42.97 |
| Close | 43.37 | 42.61 | 42.84 | 41.24 | 41.64 | 42.58 | 37.97 | 43.81 |
| Dividends | 0.525[(a)] | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 | 0.525 |

(a) The fourth quarter 2011 dividend does not include the first quarter 2012 regular quarterly dividend of $0.525 per share, declared by the Exelon Board of Directors on October 25, 2011. The first quarter 2012 dividend is payable on March 9, 2012, to shareholders of record of Exelon at the end of the day on February 15, 2012.

Exelon Corporation
P.O. Box 805379
Chicago, IL 60680-5379
www.exeloncorp.com

Exelon®