EXELON CORP
Form 10-K
February 14, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2013

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number	Exact Name of Registrant as Specified in its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street	23-2990190

	P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** **(a Maryland corporation)** 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
EXELON CORPORATION:	
Common Stock, without par value	New York and Chicago

Series A Junior Subordinated Debentures	New York

PECO ENERGY COMPANY:

Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, $25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	New York

BALTIMORE GAS AND ELECTRIC COMPANY:

6.20% Trust Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust II, fully and unconditionally guaranteed, by Baltimore Gas and Electric Company	New York

Securities registered pursuant to Section 12(g) of the Act:

COMMONWEALTH EDISON COMPANY:

Common Stock Purchase Warrants, 1971 Warrants and Series B Warrants

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Exelon Corporation	Yes x No ¨
Exelon Generation Company, LLC	Yes x No ¨
Commonwealth Edison Company	Yes x No ¨
PECO Energy Company	Yes x No ¨
Baltimore Gas and Electric Company	Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Exelon Corporation	Yes ¨ No x
Exelon Generation Company, LLC	Yes ¨ No x
Commonwealth Edison Company	Yes ¨ No x
PECO Energy Company	Yes ¨ No x
Baltimore Gas and Electric Company	Yes ¨ No x

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, non-accelerated filer, or a smaller reporting company. See definition of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

	Large Accelerated	**Accelerated**	**Non-Accelerated**	**Small Reporting Company**
Exelon Corporation	ü			
Exelon Generation Company, LLC			ü	
Commonwealth Edison Company			ü	
PECO Energy Company			ü	
Baltimore Gas and Electric Company			ü	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Exelon Corporation	Yes ¨	No x
Exelon Generation Company, LLC	Yes ¨	No x
Commonwealth Edison Company	Yes ¨	No x
PECO Energy Company	Yes ¨	No x
Baltimore Gas and Electric Company	Yes ¨	No x

The estimated aggregate market value of the voting and non-voting common equity held by nonaffiliates of each registrant as of June 30, 2013 was as follows:

Exelon Corporation Common Stock, without par value	$ 26,430,683,706
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	No established market
PECO Energy Company Common Stock, without par value	None
Baltimore Gas and Electric Company, without par value	None

The number of shares outstanding of each registrant s common stock as of January 31, 2014 was as follows:

Exelon Corporation Common Stock, without par value	857,419,806
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,904
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company, without par value	1,000

Documents Incorporated by Reference

Portions of the Exelon Proxy Statement for the 2014 Annual Meeting of

Shareholders and the Commonwealth Edison Company 2014 information statement are

incorporated by reference in Part III.

Exelon Generation Company, LLC, PECO Energy Company and Baltimore Gas and Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form in the reduced disclosure format.

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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
BGE	Baltimore Gas and Electric Company
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon s holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
ComEd Financing III	ComEd Financing III
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Energy Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
BGE Trust II	BGE Capital Trust II
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd, PECO and BGE, collectively
Other Terms and Abbreviations	
1998 restructuring settlement	PECO s 1998 settlement of its restructuring case mandated by the Competition Act
Act 11	Pennsylvania Act 11 of 2012
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	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
AESO	Alberta Electric Systems Operator
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

Other Terms and Abbreviations

Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDF	Electricite de France SA
EE&C	Energy Efficiency and Conservation/Demand Response
EIMA	Illinois Energy Infrastructure Modernization Act
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
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
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.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out
LLRW	Low-Level Radioactive Waste

Other Terms and Abbreviations

LTIP	Long-Term Incentive Plan
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody s	Moody s Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
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
NSPS	New Source Performance Standards
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
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

Other Terms and Abbreviations	
Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor s Ratings Services
SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SERP	Supplemental Employee Retirement Plan
SGIG	Smart Grid Investment Grant
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMP	Smart Meter Program
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
TEG	Termoelectrica del Golfo
TEP	Termoelectrica Penoles
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

FILING FORMAT

This combined Annual Report on Form 10-K is being filed separately by the Registrants. Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this Report are forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by a Registrant include those factors discussed herein, including those factors with respect to such Registrant discussed in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, (c) ITEM 8. Financial Statements and Supplementary Data: Note 22 and (d) other factors discussed herein and in other filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The public may read and copy any reports or other information that the Registrants file with the SEC at the SEC s public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants websites at www.exeloncorp.com. Information contained on the Registrants websites shall not be deemed incorporated into, or to be a part of, this Report.

PART I

ITEM 1. BUSINESS

General

Corporate Structure and Business and Other Information

Exelon, incorporated in Pennsylvania in February 1999, is a utility services holding company engaged, through Generation, in the energy generation business, and through ComEd, PECO and BGE, 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 integrated business consists of its owned and contracted electric generating facilities and investments in generation ventures that are marketed through its leading customer-facing activities. These customer-facing activities include, wholesale energy marketing operations and its competitive retail customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other 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 natural gas 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.

BGE

BGE 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 central Maryland, including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in central Maryland, including the City of Baltimore.

BGE was incorporated in Maryland in 1906. BGE s principal executive offices are located at 110 West Fayette Street, Baltimore, Maryland 21201, and its telephone number is 410-234-5000.

Operating Segments

See Note 24 of the Combined Notes to Consolidated Financial Statements for additional information on Exelon s operating segments.

Merger with Constellation Energy Group, Inc.

On March 12, 2012, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation s interest in RF HoldCo LLC, which holds Constellation s interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon s interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including those with generation and customer supply operations that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information on the Constellation transaction.

Generation

Generation, one of the largest competitive electric generation companies in the United States as measured by owned and contracted MW, physically delivers and markets power across multiple geographic regions through its customer-facing business, Constellation. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets. Generation operates as an integrated business, leveraging its owned and contracted electric generation capacity to market and sell power to wholesale and retail customers. Generation s customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation also sells natural gas and renewable energy and other energy-related products and services, and engages in natural gas exploration and production activities.

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

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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. Additionally, ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. 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 and ISOs exist in a number of regions to provide transmission service across multiple transmission systems. PJM, MISO, ISO-NE and SPP, have been approved by FERC as RTOs, and CAISO and ISO-NY have been approved as ISOs. These entities are responsible for regional planning, managing transmission congestion, developing wholesale markets for energy and capacity, maintaining reliability, market monitoring, the scheduling of physical power sales brokered through ICE and NYMEX and the elimination or reduction of redundant transmission charges imposed by multiple transmission providers when wholesale customers take transmission service across several transmission systems.

Significant Acquisitions

Antelope Valley Solar Ranch One. On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which is developing, building, operating, and maintaining the project. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013. Exelon has been informed by First Solar of issues relating to delays in the certification of certain components relating to the final two blocks of the project, which will delay commercial operation of these two blocks until the first half of 2014. The delay will not have a material financial effect on Exelon. Exelon expects the project to be in full commercial operation in the first half of 2014. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA, approved by the CPUC, with Pacific Gas & Electric Company for the full output of the plant. Upon completion, the facility will add 230 MWs to Generation s renewable generation fleet. Total capitalized costs for the facility are expected to be approximately $1.1 billion. Total capitalized costs incurred through December 31, 2013 were approximately $968 million.

Wolf Hollow Generating Station. 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, for a purchase price of $311 million which increased Generation s owned capacity within the ERCOT power market by 720 MWs.

See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information on the above acquisitions.

Significant Dispositions

Maryland Clean Coal Stations. On November 30, 2012, a subsidiary of Generation sold the Brandon Shores generating station and H.A. Wagner generating station in Anne Arundel County, Maryland, and the C.P. Crane generating station in Baltimore County, Maryland to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC to comply with certain of the regulatory approvals required by the merger, for net proceeds of approximately $371 million, which resulted in a pre-tax loss of $272 million. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

Generating Resources

At December 31, 2013, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets [(a)]	
Nuclear	17,263
Fossil	12,165
Renewable (including Hydroelectric) [(b)]	3,710
Owned generation assets	33,138
Long-term power purchase contracts [(c)]	9,426
Investment in CENG [(d)]	1,999
Total generating resources	44,563

(a) See Fuel for sources of fuels used in electric generation.
(b) Includes equity method investment in certain generating facilities.
(c) Excludes contracts with CENG. See Long-Term Power Purchase Contracts table in this section for additional information.
(d) Generation owns a 50.01% interest in CENG, a joint venture with EDF. See ITEM 2. PROPERTIES Generation and Note 25 Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Generation has six reportable segments, the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions, representing the different geographical areas in which Generation s customer-facing activities are conducted and where Generation s generating resources are located.

Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina (approximately 37% of capacity).

Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee; and the United States footprint of MISO excluding MISO s Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, and the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM; and parts of Montana, Missouri and Kentucky (approximately 34% of capacity).

New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont (approximately 8% of capacity).

New York represents the operations within ISO-NY, which covers the state of New York in its entirety (approximately 3% of capacity).

ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas (approximately 12% of capacity).

Other Regions is an aggregate of regions not considered individually significant (approximately 6% of capacity).

Nuclear Facilities

Generation has ownership interests in eleven nuclear generating stations currently in service, consisting of 19 units with an aggregate of 17,263 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), which are consolidated on Exelon s financial statements relative to its proportionate ownership interest in each unit. 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 2013 and 2012, electric supply (in GWh) generated from the nuclear generating facilities was 57% and 53%, respectively, of Generation s total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. The majority of this output was dispatched to support Generation s wholesale and retail power marketing activities. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of Generation s electric supply sources.

Constellation Energy Nuclear Group, Inc.

Generation also owns a 50.01% interest in CENG, a joint venture with EDF. CENG is governed by a board of ten directors, five of which are appointed by Generation and five by EDF. CENG owns and operates a total of five nuclear generating facilities on three sites, Calvert Cliffs, Ginna and Nine Mile Point. CENG s ownership share in the total capacity of these units is 3,998 MW. See ITEM 2. PROPERTIES for additional information on these sites.

On July 29, 2013, Exelon, Generation and subsidiaries of Generation entered into a Master Agreement with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG. The Master Agreement contemplates that the parties will execute a series of additional agreements at a closing that will occur following the receipt of regulatory approvals and the satisfaction of other customary closing conditions. Exelon currently expects that the closing will occur early in the second quarter of 2014.

At the closing, Generation, CENG and subsidiaries of CENG will execute a Nuclear Operating Services Agreement pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDFI s rights as a member of CENG. CENG will reimburse Generation for its direct and allocated costs for such services. The Nuclear Operating Services Agreement will replace the SSA. At the closing, Nine Mile Point Nuclear Station, a subsidiary of CENG, will also assign to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with the co-owner. In addition, at the closing the PSAA will be amended and extended until the complete and permanent cessation of operation of the CENG generation plants.

At closing, Generation will make a $400 million loan to CENG bearing interest at 5.25% per annum, payable out of specified available cash flows of CENG and, in any event, payable upon settlement of the Put Option Agreement discussed below, if the put option is exercised, or payable upon the maturity date of the note (which will be 20 years from the closing), whichever occurs first. Immediately following receipt of the proceeds of such loan, CENG will make a $400 million special distribution to EDFI. The parties will also execute a Fourth Amended and Restated Operating Agreement for CENG, pursuant to which, among other things, CENG will commit to make preferred distributions to Generation (after repayment of the $400 million loan) quarterly out of specified available cash flows, until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from the date of the special distribution to EDFI.

Generation and EDFI will also enter into a Put Option Agreement at closing pursuant to which EDFI will have the option, exercisable beginning in 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third party arbitration process. The appraisers determining fair market value of EDF s 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation s rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation s rights to other distributions. The beginning of the exercise period will be accelerated if

Exelon s affiliates cease to own a majority of CENG and exercise a related right to terminate the Nuclear Operating Services Agreement. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

Generation will execute an Indemnity Agreement pursuant to which Generation will indemnify EDF and its affiliates against third party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon will guarantee Generation s obligations under this indemnity.

CENG owns 100% of four nuclear units in Maryland and New York and 82% of Nine Mile Point Unit 2 in New York. Generation currently has an agreement under which it is purchasing 85% of the nuclear plant output owned by CENG that is not sold to third parties under pre-existing firm and unit contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit contingent basis 50.01% of the nuclear plant output owned by CENG, and EDF will purchase on a unit contingent basis 49.99% of the nuclear plant output owned by CENG (EDF PPA). This agreement will continue to be effective and is not affected by the Master Agreement, except that if the put option under the Master Agreement is exercised, then the EDF PPA would transfer to Generation upon the completion of the Put Option Agreement transaction.

Currently, Exelon and Generation account for its investment in CENG under the equity method of accounting. The transfer of the operational control to Exelon and Generation will result in Exelon and Generation being required to consolidate the financial position and results of operations of CENG. When that accounting change occurs, Exelon and Generation will derecognize its equity method investment in CENG and will record all assets, liabilities and the non-controlling interest in CENG at fair value on Exelon and Generation s balance sheets. Any difference between the former carrying value and newly recorded fair value at that date will be recognized as a gain or loss upon consolidation, which could be material to Exelon s and Generation s results of operations. See Note 5 Investment in CENG of the Combined Notes to Consolidated Financial Statements for additional information regarding CENG.

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 operations from its nuclear plants have historically had minimal environmental impact and the plants have a safe operating history.

During 2013 and 2012, the nuclear generating facilities operated by Generation achieved capacity factors of 94.1% and 92.7%, respectively. Generation 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 wholesale and retail 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

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assesses unit performance indicators and inspection results, and communicates its assessment on a semi-annual basis. As of December 31, 2013, the NRC categorized Dresden units 2 and 3, LaSalle unit 2, and Clinton in the Regulatory Response Column, which is the second highest of five performance bands. All other units operated by Generation are categorized in the Licensee Response Column as of December 31, 2013, which is the highest performance band. On January 1, 2014, Dresden units 2 and 3 returned to the Licensee Response Column. 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. In July 2011, an NRC Task Force formed in the aftermath of the Fukushima Daiichi events 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 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 NRC and its staff have issued orders and implementation guidance for commercial reactor licensees operating in the United States. The NRC and its staff are continuing to evaluate additional requirements. For additional information on the NRC actions related to the Japan Earthquake and Tsunami and the industry s response, see ITEM 7. 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 has received 20-year operating license renewals for Salem Units 1 and 2. On December 8, 2010, 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 [(b)]	1	1988	2026
	2	1988	2027
Byron [(b)]	1	1985	2024
	2	1987	2026
Clinton	1	1987	2026
Dresden [(c)]	2	1970	2029
	3	1971	2031
LaSalle	1	1984	2022
	2	1984	2023
Limerick [(d)]	1	1986	2024
	2	1990	2029
Oyster Creek [(c)(e)]	1	1969	2029
Peach Bottom [(c)]	2	1974	2033
	3	1974	2034
Quad Cities [(c)]	1	1973	2032
	2	1973	2032
Salem [(c)]	1	1977	2036
	2	1981	2040
Three Mile Island [(c)]	1	1974	2034

(a) Denotes year in which nuclear unit began commercial operations.
(b) On May 29, 2013, Generation submitted applications to the NRC to extend the operating licenses of Braidwood Units 1 and 2 and Byron Units 1 and 2 by 20 years.
(c) Stations for which the NRC has issued a renewed operating licenses.
(d) In June 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years.
(e) In December 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019.

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.

In August 2012, Generation entered into an operating services agreement with the Omaha Public Power District (OPPD) to provide operational and managerial support services for the Fort Calhoun Station and a licensing agreement for use of the Exelon Nuclear Management Model. The terms for both agreements are 20 years. OPPD will continue to own the plant and remain the NRC licensee.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects. The Measurement Uncertainty Recapture uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. Additionally, the market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. During 2013, Generation recorded a pre-tax charge to operating and maintenance expense and interest expense of approximately $111 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Under the nuclear uprate program, Generation has placed into service projects representing 316 MWs of new nuclear generation at a cost of $952 million, which has been capitalized to property, plant and equipment on Exelon s and Generation s consolidated balance sheets. At December 31, 2013, Generation has capitalized $203 million to construction work in progress within property, plant and equipment for nuclear uprate projects expected to be placed in service by the end of 2016, consisting of 200 MWs of new nuclear generation, that are in the installation phase across four nuclear stations; Peach Bottom in Pennsylvania and Byron, Braidwood and Dresden in Illinois. The remaining spend associated with these projects is expected to be approximately $300 million through the end of 2016. Generation believes that it is probable that these projects will be completed. If a project is expected not to be completed as planned, previously capitalized costs will be reversed through earnings as a charge to operating and maintenance expense and interest.

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, 2013, Generation had approximately 59,900 SNF assemblies (14,400 tons) stored on site in SNF pools or dry cask storage (this includes SNF assemblies at Zion Station, for which Generation retains ownership even though the responsibility for decommissioning Zion Station has been assumed by another party; see Note 15 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning). All currently operating Generation-owned nuclear sites have on-site dry cask storage, except for Clinton and Three Mile Island. Clinton and Three Mile Island will currently lose full core reserve, which is when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core, in 2015 and 2023, respectively. Dry cask storage will be in operation at Clinton and is expected to be in operation at Three Mile Island prior to the closing of their respective on-site storage pools. 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.

For a discussion of matters associated with Generation s contracts with the DOE for the disposal of SNF, see Note 22 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 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 such 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 NRC approval for its Peach Bottom and LaSalle stations that will allow storage at these sites of LLRW from its remaining stations with 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. During 2012, Generation entered into a six year contract to ship Class B and Class C LLRW to Texas. The terms of the agreement will provide for disposal of all current Class B and Class C LLRW stored at the stations, as well as the waste generated during the term of the agreement. Although Texas started accepting waste for disposal in 2012, the Texas site is curie limited (3.9 million curies for 15 years). With this limit, the annual facility volume will not match industry production of activated hardware, and on-site storage is expected to be required for the Generation boiling water reactors. 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 major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See Nuclear Insurance within Note 22 of the Combined Notes to Consolidated Financial Statements for details.

For information regarding property insurance, see ITEM 2. PROPERTIES Generation. 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 ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Exelon Corporation, Executive Overview; ITEM 7. 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 3, 11 and 15 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 ARO liability to decommission Dresden Unit 1 and Peach Bottom Unit 1 as of December 31, 2013 was $208 million and $114 million, respectively. As of December 31, 2013, NDT funds set aside to pay for these obligations were $436 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 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, excluding the obligation to dispose of SNF, associated with Zion Station. Pursuant to the ASA, ZionSolutions will 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 15 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning and see Note 2 of the Combined Notes to Consolidated Financial Statements for a discussion of variable interest entity considerations related to ZionSolutions.

Fossil and Renewable Facilities (including Hydroelectric)

Generation has ownership interests in 15,875 MW of capacity in fossil and renewable generating facilities currently in service. Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) jointly owned facilities that include Keystone, Conemaugh, and Wyman; (2) ownership interests through equity method investments in Colver, Malacha, Safe Harbor, and Sunnyside; and (3) certain wind project entities with minority interest owners, see Note 2 of the Combined Notes to Consolidated Financial Statements for additional information on these wind project entities. Generation s fossil and renewable generating stations are all operated by Generation, with the exception of Colver, Conemaugh, Keystone, LaPorte, Malacha, Safe Harbor, Sunnyside and Wyman, which are operated by third parties. In 2013 and 2012, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 15% and 12%, respectively, of Generation s total electric supply. The majority of this output was dispatched to support Generation s wholesale and retail power marketing activities. For additional information regarding Generation s electric generating facilities, see ITEM 2. PROPERTIES Generation and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Exelon Corporation, Executive Overview for additional information on Generation Renewable Development.

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. On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Muddy Run Pumped Storage Project and the Conowingo Hydroelectric Project, respectively. Based on the latest FERC procedural schedule, the FERC licensing process is not expected to be completed prior to the expiration of Muddy Run s current license on August 31, 2014, and the expiration of Conowingo s license on September 1, 2014. However, the stations will continue to operate under annual licenses until FERC takes action on the 46-year license applications. Refer to Note 3 Regulatory Matters for additional information.

Insurance. Generation maintains business interruption insurance for its renewable projects, and delay in start-up insurance for its renewable 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 for these operations, 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.

Long-Term Power Purchase Contracts

In addition to energy produced by owned generation assets, Generation sources electricity and other related output from plants it does not own under long-term contracts. The following tables summarize Generation s long-term contracts to purchase unit-specific physical power with an original term in excess of one year in duration, by region, in effect as of December 31, 2013:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic [a]	16	2016 - 2032	799
Midwest	7	2015 - 2022	1,734
New England	14	2014 - 2020	1,291
ERCOT	5	2014 - 2026	1,489
Other Regions	11	2014 - 2030	4,113
Total	53		9,426

	2014	2015	2016	2017	2018
Capacity Expiring (MW)	1,300	1,705	651	1,337	100

(a) Excludes contracts with CENG.

Fuel

The following table shows sources of electric supply in GWh for 2013 and 2012:

	Source of Electric Supply [a]	
	2013	**2012**
Nuclear	142,126	139,862
Purchases non-trading portfolio[b]	69,791	91,994
Fossil	30,785	27,760
Renewable	6,420	4,079
Total supply	249,122	263,695

(a) Represents Generation s proportionate share of the output of its generating plants.
(b) Includes purchases pursuant to Generation s PPA with CENG. See Note 25 of the Combined Notes to Consolidated Financial Statements for additional information.

The fuel costs for nuclear generation are less than those for fossil-fuel generation. Consequently, nuclear generation is generally the most cost-effective way for Generation to meet its wholesale and retail load servicing 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 2016. Generation s contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2020. All of Generation s enrichment requirements have been contracted through 2018. Contracts for fuel fabrication have been obtained through 2018. 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 long-term and short-term contracts, as well as spot-market purchases. 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, using both over-the-counter and exchange-traded instruments. See ITEM 1A. RISK FACTORS, ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Marketing

Generation s integrated business 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 maintains an effective supply strategy through ownership of generation assets and power purchase and lease agreements. 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 depending on the type of underlying asset. Generation secures contracted generation as part of its overall strategic plan, with objectives such as obtaining low-cost energy supply sources to meet its physical delivery obligations to both wholesale and retail customers and assisting customers to meet renewable portfolio standards. Generation may buy power to meet the energy demand of its customers, including ComEd, PECO and BGE. Generation sells electricity, natural gas, and related products and solutions to various customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in competitive markets. Generation s customer facing operations combine a unified sales force with a customer-centric model that leverages technology to broaden the range of products and solutions offered, which Generation believes promotes stronger customer relationships. This model focuses on efficiency and cost reduction, which provides a platform that is scalable and able to capitalize on opportunities for future growth.

Generation s purchases may be for more than the energy demanded by Generation s customers. Generation 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 actively manages these physical and contractual assets in order to derive incremental value. Additionally, Generation is involved in the development, exploration, and harvesting of oil, natural gas and natural gas liquids properties.

Price Supply Risk Management

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. Generation is exposed to relatively greater commodity price risk in 2014 and beyond 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, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015, and 2016, 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, including purchased power from CENG. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including sales to ComEd, PECO and BGE 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. Generation also uses financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of Generation s efforts. 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 wholesale and retail power marketing activities. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

At December 31, 2013, Generation s short and long-term commitments relating to the purchase of energy and capacity from and to unaffiliated utilities and others were as follows:

(in millions)	Net Capacity Purchases (a)	REC Purchases (b)	Transmission Rights Purchases (c)	Purchased Energy from CENG	Total
2014	$ 412	$ 117	$ 25	$ 824	$ 1,378
2015	367	110	13		490
2016	284	76	2		362
2017	223	25	2		250
2018	112	3	2		117
Thereafter	414	3	32		449
Total	$ 1,812	$ 334	$ 76	$ 824	$ 3,046

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation s expected payments under these arrangements at December 31, 2013, net of fixed capacity payments expected to be received by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. Expected payments include certain fixed capacity charges which may be reduced on plant availability.
(b) The table excludes renewable energy purchases 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.

As part of reaching a comprehensive agreement with EDF in October 2010, the existing power purchase agreements with CENG were modified to be unit-contingent through the end of their original term in 2014. Under these agreements Generation purchases 85% of the nuclear plant output owned by CENG that is not sold to third parties. CENG has the ability to fix the energy price on a forward basis by entering into monthly energy hedge transactions for a portion of the future sale, while any unhedged portions will be provided at market prices by default. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, Generation agreed to purchase 50.01% of the nuclear plant output owned by CENG at market prices. This purchase agreement will continue to be effective under the Master Agreement discussed above, except that if the put option under the Master Agreement is exercised, then the EDF PPA will be transferred to Generation upon the completion of the Put Option Agreement transaction. Generation discloses in the table above commitments to purchase from CENG at fixed prices. All commitments to purchase from CENG at market prices, which include all purchases subsequent to December 31, 2014, are excluded from the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 25 of the Combined Notes to Consolidated Financial Statements for more details on this arrangement.

Capital Expenditures

Generation s business is capital intensive and requires significant investments in nuclear fuel and energy generation assets and in other internal infrastructure projects. Generation s estimated capital expenditures for 2014 are as follows:

(in millions)	
Nuclear fuel (a)	$ 900
Production plant	900
Renewable energy projects	300
Uprates	150
Maryland commitments	100
Other	50
Total	$ 2,400

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

ComEd

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

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 2.7 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 2014 to 2066. ComEd anticipates working with the appropriate agencies to extend or replace the franchise agreements prior to expiration.

ComEd s kWh deliveries 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 6, 2014, and was 16,514 MWs.

Retail Electric Services

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 a competitive electric generation supplier. The customers choice activity affects revenue collected from customers related to supplied energy; however, that activity has no impact on electric revenue net of purchased power expense. ComEd s cost of electric supply is passed without markup directly through to those customers not served by a competitive electric generation supplier and those rates are subject to adjustment monthly to recover or refund the difference between ComEd s actual cost of electricity delivered and the amount included in rates. For those customers that choose a competitive electric generation supplier, ComEd acts as the billing agent but does not record revenues or expenses related to the electric supply. ComEd remains the distribution service provider for all customers in its service territory and charges a regulated rate for distribution service. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information on customer switching to competitive electric generation suppliers, and Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s electricity procurement process and for additional information.

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 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.

Energy Infrastructure Modernization Act (EIMA). Since 2011, ComEd s distribution rates are established through a performance-based rate formula pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois electric utility infrastructure. In addition, as long as ComEd is subject to EIMA, ComEd will fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates.

ComEd files an annual reconciliation of the revenue requirement in effect in a given year to reflect the actual costs that the ICC determines are prudently and reasonably incurred for such year. 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. See Note 3 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. On February 23, 2012, the ICC issued an order in the remand proceeding requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). On September 27, 2013, the Court ruled against ComEd on the accumulated depreciation issue and affirmed that ComEd owes a refund to customers of $37 million. As of December 31, 2013, and December 31, 2012, ComEd was fully reserved for this liability. ComEd will not seek rehearing or appeal on this matter and is working with the ICC on the process and timing for a refund to customers.

On May 24, 2011, the ICC issued an order in ComEd s 2010 electric distribution rate case (2010 Rate Case), which became effective on June 1, 2011. The order approved a $143 million increase to ComEd s annual delivery service revenue requirement and a 10.5% rate of return on common equity. The order has been appealed to the Court by several parties. On May 16, 2013, the Court dismissed as moot the appeals of the ICC s order in the 2010 Rate Case as ComEd now recovers distribution costs under EIMA through a pre-established formula rate tariff. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s electric distribution rate cases.

Procurement-Related Proceedings. Since June 2009, 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. As required by EIMA, in February 2012 the IPA completed procurement events for energy and REC requirements for the June 2013 through December 2017 period. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s procurement plans. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s energy commitments.

Continuous Power Interruption. The Illinois Public Utilities Act 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) more than 30,000 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. See Note 22 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Smart Meter, Smart Grid and Energy Efficiency Programs

Smart Meter and Smart Grid Programs. On January 6, 2012, ComEd filed its Infrastructure Investment Plan with the ICC. Under that plan, ComEd will invest approximately $2.6 billion over ten years to modernize and storm-harden its distribution system and to implement smart grid technology. On April 23, 2012, ComEd filed its initial AMI Deployment Plan with the ICC, which was approved by the ICC on June 22, 2012, with certain modifications. ComEd outlined the new deployment schedule within testimony provided in the AMI Plan Rehearing and filed a revised AMI deployment plan with the ICC. On December 5, 2012, the ICC approved ComEd s revised AMI deployment plan. On June 5, 2013, the ICC issued an interim Order approving ComEd s accelerated AMI deployment plan consistent with the provisions of Senate Bill 9. The deployment plan provides for the installation of 4 million electric smart meters, of which more than 60,000 meters were installed by the end of 2013.

Energy Efficiency Programs. 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 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.

EIMA provides for additional energy efficiency in Illinois. Starting in the June 2013 May 2014 period and occurring annually thereafter, as part of the IPA procurement plan, ComEd is to include cost-effective expansion of current energy efficiency programs, any additional new cost-effective program and/or third-party energy efficiency programs that are identified through a request for proposal (RFP) process. All cost-effective energy efficiency programs are included in the IPA procurement plan for consideration of implementation. While these programs are monitored separately from the Energy Efficiency Portfolio Standard (EEPS), funds for both the EEPS portfolio and IPA energy efficiency programs are collected under the same rider.

Construction Budget

ComEd s business is capital intensive and requires significant investments primarily in energy transmission and distribution facilities, to ensure the adequate capacity, reliability and efficiency of its system. Based on PJM s RTEP, ComEd has various construction commitments, as discussed in Note 3 of the Combined Notes to Consolidated Financial Statements. ComEd s most recent estimate of capital expenditures for electric plant additions and improvements for 2014 is $1,775 million, which includes RTEP projects and infrastructure modernization resulting from EIMA. See ITEM 7. 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 gas 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 501,000 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 January 7, 2014 and was 7,148 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 7, 2014 and was 760 mmcf.

Retail Electric Services

PECO s retail electric sales and distribution service revenues are derived pursuant to rates regulated by the PAPUC. Pennsylvania permits competition by competitive electric generation suppliers for the supply of retail electricity while retail transmission and distribution service remains regulated under the Competition Act. At December 31, 2013, there were 87 competitive electric generation suppliers serving PECO customers. At December 31, 2013, the number of retail customers purchasing energy from a competitive electric generation supplier was 531,500 representing approximately 34% of total retail customers. Retail deliveries purchased from competitive electric generation suppliers represented approximately 68% of PECO s retail kWh sales for the year ended December 31, 2013. Customers that choose a competitive electric generation supplier 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 competitive electric generation suppliers.

Customer choice program activity affects revenue collected from customers related to supplied energy; however, that activity has no impact on electric revenue net of purchased power expense or PECO s financial position. PECO s cost of electric supply is passed directly through to default service

customers without markup and those rates are subject to adjustment at least quarterly to recover or refund the difference between PECO s actual cost of electricity delivered and the amount included in rates through the GSA. For those customers that choose a competitive electric generation supplier, PECO acts as the billing agent but does not record revenues or purchase power expense 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.

Procurement Proceedings. PECO s electric supply for its customers is procured through contracts executed in accordance with its PAPUC-approved DSP Programs. PECO entered into contracts with PAPUC-approved bidders, including Generation, as part of its DSP I 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. In September 2012, PECO completed its last competitive procurement for electric supply under its first DSP Program, which expired on May 31, 2013.

On October 12, 2012, the PAPUC approved PECO s second DSP Program, which was filed with the PAPUC in January 2012. The plan outlines how PECO is purchasing electric supply for default service customers from June 1, 2013 through May 31, 2015. Pursuant to the second DSP Program, PECO is procuring electric supply through five competitive procurements for fixed price full requirements contracts of two years or less for the residential and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load. In December 2012 and February 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in June 2013. In September 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in December 2013. In January 2014, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small, medium and large commercial classes that will begin in June 2014. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO s Statement of Operations and Comprehensive Income.

The second DSP Program also includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from competitive electric generation suppliers beginning April 1, 2014. On May 1, 2013, PECO filed a Petition for Approval of its CAP Shopping Plan with the PAPUC, which the PAPUC granted and denied in part on January 9, 2014. PECO and other parties to the proceeding filed petitions for reconsideration of the Commission s decision on February 10, 2014, and these petitions are currently pending before the PAPUC.

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

Smart Meter, Smart Grid and Energy Efficiency Programs

Smart Meter and Smart Grid Programs. In April 2010, the PAPUC approved PECO s 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. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. On January 18, 2013, PECO filed with the PAPUC its universal deployment plan for approval of its proposal to deploy the remainder of the 1.6 million smart meters on an accelerated basis by the end of 2014. On May 31, 2013, PECO and interested parties filed a Joint Petition for Settlement of the universal deployment plan with the PAPUC, which was approved without modification on August 15, 2013. In total, PECO currently expects to spend up to $595 million and $120 million on its smart meter and smart grid infrastructure, respectively, before considering the $200 million SGIG.

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

Energy Efficiency Programs. PECO s PAPUC-approved Phase I EE&C plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I Plan sets forth how PECO would meet the required reduction targets established by Act 129 s EE&C provisions, which included a 3% reduction in electric consumption in PECO s service territory and a 4.5% reduction in PECO s annual system peak demand in the 100 hours of highest demand by May 31, 2013. The peak demand period ended on September 30, 2012 and PECO communicated its compliance with the reduction targets in a preliminary report with the PAPUC on March 1, 2013. The final compliance report was filed with the PAPUC on November 15, 2013.

The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provides energy consumption reduction requirements for the second phase of Act 129 s EE&C programs, which went into effect on June 1, 2013. The PAPUC deferred a decision on peak demand reduction requirements until late 2013. On February 28, 2013, the PAPUC approved PECO s three-year EE&C Phase II plan that was filed with the PAPUC on November 1, 2012, and sets forth how PECO will reduce electric consumption by at least 1,125,852 MWh in its service territory for the period June 1, 2013 through May 31, 2016.

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

Natural Gas

PECO s natural gas sales and distribution service revenues are derived through natural gas deliveries at 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. At December 31, 2013, the number of retail customers purchasing natural gas from a competitive natural gas supplier was 66,400, representing approximately 13% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 19% of PECO s mmcf sales for the year ended December 31, 2013. PECO provides distribution, billing, metering, installation, maintenance and emergency response services at regulated rates to all its customers in its service territory.

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 three years in accordance with its annual PAPUC PGC settlement. PECO s aggregate annual firm supply under these firm transportation contracts is 34 million dekatherms. Peak natural gas is provided by PECO s liquefied natural gas (LNG) facility and propane-air plant. PECO also has under contract 21 million dekatherms of underground storage through service agreements. Natural gas from underground storage represents approximately 30% of PECO s 2013-2014 heating season planned supplies.

See Note 3 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 3 of the Combined Notes to Consolidated Financial Statements. PECO s most recent estimate of capital expenditures for plant additions and improvements for 2014 is $625 million, which includes RTEP projects and capital expenditures related to the smart meter and smart grid project net of expected SGIG DOE reimbursements.

BGE

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

BGE serves an estimated population of 2.8 million in its 2,300 square mile combined electric and gas retail service territory. BGE provides electric distribution service in an area of approximately 2,300 square miles and gas distribution service in an area of approximately 800 square miles, both with a population of approximately 2.8 million, including approximately 621,000 in the City of Baltimore. BGE delivers electricity to approximately 1.2 million customers and natural gas to approximately 655,000 customers.

BGE has the necessary authorizations to provide regulated electric and natural gas distribution services in the various municipalities and territories in which it now supplies such services. With respect to electric distribution service, BGE s authorizations consist of charter rights, a state-wide franchise grant and a franchise grant from the City of Baltimore. The franchise rights are not exclusive and are perpetual. With respect to natural gas distribution service, BGE s authorizations consist of charter rights, a perpetual state-wide franchise grant, and franchises granted by all the municipalities and/or governmental bodies in which BGE now supplies services. The franchise grants are not exclusive; some are perpetual and some are for a limited duration, which BGE anticipates being able to extend or replace prior to expiration.

BGE 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. BGE s highest peak load occurred on July 21, 2011 and was 7,236 MW; its highest peak load during winter months occurred on January 7, 2014 and was 6,526 MW.

BGE s natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating. BGE s highest daily natural gas send out occurred on February 5, 2007 and was 840 mmcf.

The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per

customer on BGE s electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This adjustment allows BGE to recognize revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period (referred to as revenue decoupling). Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits affected customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Retail Electric Services

BGE s retail electric sales and distribution service revenues are derived from electricity deliveries at rates regulated by the MDPSC. As a result of the deregulation of electric generation in Maryland effective July 1, 2000, all customers can choose a competitive electric generation supplier. While BGE does not sell electric supply to all customers in its service territory, BGE continues to deliver electricity to all customers and provides meter reading, billing, emergency response, and regular maintenance services. Customer choice program activity affects revenue collected from customers related to supplied energy; however, that activity has minimal impact on electric revenue net of purchased power expense or BGE s financial position. At December 31, 2013, there were 73 competitive electric generation suppliers serving BGE customers. At December 31, 2013, the number of retail customers purchasing energy from a competitive electric generation supplier was approximately 399,000, representing 32% of total retail customers. Retail deliveries purchased from competitive electric generation suppliers represented approximately 61% of BGE s retail kWh sales for the year ended December 31, 2013.

BGE is obligated to provide market-based SOS to all of its electric customers. The SOS rates charged recover BGE s wholesale power supply costs and include an administrative fee. The administrative fee includes a commercial and industrial shareholder return component and an incremental cost component. Bidding to supply BGE s market-based SOS occurs through a competitive bidding process approved by the MDPSC. Successful bidders, which may include Generation, will execute contracts with BGE for terms of three months or two years.

BGE is obligated by the MDPSC to provide several variations of SOS to commercial and industrial customers depending on customer load.

Electric Distribution Rate Cases. In December 2010, the MDPSC issued an abbreviated electric rate order authorizing BGE to increase electric distribution rates for service rendered on or after December 4, 2010 by no more than $31 million. In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated combined electric and gas distribution rate order issued in December 2010. As part of the March 2011 comprehensive rate order, BGE was authorized to defer $19 million of costs as regulatory assets. These costs are being recovered over a 5-year period beginning in December 2010 and include the deferral of $16 million of storm costs incurred in February 2010. The regulatory asset for the storm costs earns the authorized rate of return.

On July 27, 2012, BGE filed an application for an increase to its electric base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order in BGE s 2012 electric rate case for increases in annual distribution service revenue of $81 million. The electric distribution rate increase was set using an allowed return on equity of 9.75%.

On May 17, 2013, BGE filed an application for an increase to its electric base rates with the MDPSC. On December 13, 2013, the MDPSC issued an order in BGE s 2013 electric distribution rate case authorizing an increase in annual distribution service revenue of $34 million. The electric distribution rate increase was set using an allowed return on equity of 9.75%. The approved electric distribution rate became effective for services rendered on or after December 13, 2013.

Smart Meter and Energy Efficiency Programs

Smart Meter Programs. In August 2010, the MDPSC approved BGE s $480 million SGIP, which includes deployment of a two-way communications network, 2 million smart electric and gas meters and modules, new customer pricing programs, a new customer web portal and numerous enhancements to BGE operations. Also, in April 2010, BGE entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA of 2009. Under the SGIG, BGE has been awarded $200 million, the maximum grant allowable under the program, to support its Smart Grid, Peak Rewards and CC&B initiatives. The SGIG funding is being used to reduce significantly the rate impact of those investments on BGE customers. As of December 31, 2013, BGE has billed the entire $200 million grant to the DOE.

Energy Efficiency Programs. BGE s energy efficiency programs include a CFL program, retrofit programs, an energy efficient 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. The MDPSC initially approved a full portfolio of conservation programs as well as a customer surcharge to recover the associated costs. This customer surcharge is updated annually. In December 2011, the MDPSC approved BGE s conservation programs for implementation in 2012 through 2014.

Natural Gas

BGE s natural gas sales are derived pursuant to a MBR mechanism that applies to customers who buy their gas from BGE. Under this mechanism, BGE s actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE s actual cost and the market index is shared equally between shareholders and customers. Customer choice program activity affects revenue collected from customers related to supplied natural gas; however, that activity has minimum impact on gas revenue net of purchased power expense or BGE s financial position. At December 31, 2013, there were 41 competitive natural gas suppliers serving BGE customers. At December 31, 2013, the number of retail customers purchasing fuel from a competitive natural gas supplier was approximately 172,000 representing 26% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 54% of BGE s retail mmcf sales for the year ended December 31, 2013.

BGE must secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed price contracts are recovered under the MBR mechanism and are not subject to sharing. BGE meets its natural gas load requirements through firm pipeline transportation and storage entitlements. BGE s current pipeline firm transportation entitlements to serve its firm loads are 362 mmcf per day.

BGE s current maximum storage entitlements are 284 mmcf per day. To supplement its gas supply at times of heavy winter demands and to be available in temporary emergencies affecting gas supply, BGE has:

- a liquefied natural gas facility for the liquefaction and storage of natural gas with a total storage capacity of 1,055 mmcf and a daily capacity of 332 mmcf,

- a liquefied natural gas facility for natural gas system pressure support with a total storage capacity of 6 mmcf and a daily capacity of 6 mmcf, and

- a propane air facility and a mined cavern with a total storage capacity equivalent to 546 mmcf and a daily capacity of 85 mmcf.

BGE has under contract sufficient volumes of propane for the operation of the propane air facility and is capable of liquefying sufficient volumes of natural gas during the summer months for operations of its liquefied natural gas facility during peak winter periods. BGE historically has been able to arrange short-term contracts or exchange agreements with other gas companies in the event of short-term disruptions to gas supplies or to meet additional demand.

BGE also participates in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Earnings from these activities are shared between shareholders and customers. BGE makes these sales as part of a program to balance its supply of, and cost of, natural gas.

Natural Gas Distribution Rate Cases. In December 2010, the MDPSC issued a rate order authorizing BGE to increase the gas distribution base revenue requirement for service rendered on or after December 4, 2010 by no more than $9.8 million. In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated combined electric and gas distribution rate order issued in December 2010.

On July 27, 2012, BGE filed an application for an increase to its gas base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order in BGE s 2012 gas rate case for increases in annual distribution service revenue of $32 million. The electric distribution rate increase was set using an allowed return on equity of 9.60%.

On May 17, 2013, BGE filed an application for an increase to its gas base rates with the MDPSC. On December 13, 2013, the MDPSC issued an order in BGE s 2013 natural gas distribution rate case authorizing an increase in annual distribution service revenue of $12 million. The gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved natural gas distribution rate became effective for services rendered on or after December 13, 2013.

Construction Budget

BGE s business is capital intensive and requires significant investments primarily in electric and natural gas distribution and electric transmission facilities to ensure the adequate capacity, reliability and efficiency of its system. BGE, as a transmission facilities owner, has various construction commitments under PJM s RTEP as discussed in Note 3 of the Combined Notes to Consolidated Financial Statements. BGE s most recent estimate of capital expenditures for plant additions and improvements for 2014 is approximately $600 million, which includes capital expenditures related to the SGIP net of expected SGIG DOE reimbursements.

ComEd, PECO and BGE

Transmission Services

ComEd, PECO and BGE provide unbundled transmission service under rates approved 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, PECO and BGE, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates. ComEd, PECO and BGE are required to comply with FERC s Standards of Conduct regulation 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, PECO and BGE are members of PJM and provide regional transmission service pursuant to the PJM Tariff. ComEd, PECO, BGE 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.

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.

BGE s transmission rates are established based on a formula that was approved by FERC in April 2006. 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.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding transmission services.

Employees

As of December 31, 2013, Exelon and its subsidiaries had 25,829 employees in the following companies, of which 8,602 or 33% were covered by collective bargaining agreements (CBAs):

	IBEW Local 15 (a)	IBEW Local 614 (b)	Other CBAs (c)	Total Employees Covered by CBAs	Total Employees
Generation	1,690	100	1,973	3,763	11,973
ComEd	3,487			3,487	5,895
PECO		1,254		1,254	2,418
BGE					3,303
Other (d)	71		27	98	2,240
Total	5,248	1,354	2,000	8,602	25,829

(a)

A separate CBA between ComEd and IBEW Local 15, ratified on October 10, 2012, covers approximately 32 employees in ComEd s System Services Group. Generation s and ComEd s separate CBAs with IBEW Local 15 were extended through February 28, 2014.

(b) 1,254 PECO craft and call center employees in the Philadelphia service territory are covered by CBAs with IBEW Local 614. The CBAs expire on March 31, 2015. Additionally, Exelon Power, an operating unit of Generation, has an agreement with IBEW Local 614, which expires on November 3, 2016 and covers 107 employees.

(c) During 2013, Generation finalized a CBA with the Security Officer union at Oyster Creek, which will expire in 2016. Additionally, during 2013, three other 3-year agreements were negotiated: Power, IBEW Local 614, which will expire in 2016; New England ENEH, UWUA Local 369, which will expire in 2017; and New Energy IUOE Local 95-95A, which will expire in 2016. During 2012, Generation finalized CBAs with the Security Officer unions at Byron, Clinton and TMI, which expire between 2015 and 2016. During 2011, Generation finalized CBAs with the Security Officer unions at Braidwood, Dresden, LaSalle and Quad Cities, which expire between 2014 and 2015. During 2010, Generation entered into a CBA with the Security Officer union at Limerick, which expires in 2014. Additionally, during 2009, a 5-year agreement was reached with Oyster Creek Nuclear Local 1289, which expires in 2015.

(d) Other includes shared services employees at BSC.

Environmental Regulation

General

Exelon, Generation, ComEd, PECO and BGE are subject to comprehensive and complex legislation regarding environmental matters by the federal government and various state and local jurisdictions in which they operate their facilities. The Registrants are also subject to regulations administered by the U.S. EPA and various state and local environmental protection agencies. Federal, state and local regulation includes the authority to regulate air, water, and solid and hazardous waste disposal.

The Exelon board of directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental compliance and strategy, including the CEO; the Senior Vice President, Corporate Strategy and Chief Sustainability Officer; the Corporate Environmental Strategy Director and the Environmental Regulatory Strategy Director, as well as senior management of Generation, ComEd, PECO and BGE. Performance of those individuals directly involved in environmental compliance and strategy 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 compliance with laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including, 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. The respective boards of ComEd, PECO and BGE, which each include directors who also serve on the Exelon board, oversee environmental, health and safety issues related to ComEd, PECO and BGE.

Air Quality

Air quality regulations promulgated by the U.S. EPA and the various state and local environmental agencies in Illinois, Maryland, Massachusetts, New York, Pennsylvania and Texas in accordance with the Federal Clean Air Act 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 Clean Air Act establishes a comprehensive and complex national program to reduce substantially air pollution from power plants. Advanced emission controls for SO_2 and NOx have been installed at all of Generation s co-owned bituminous coal-fired units.

See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding clean air regulation and legislation in the forms of the CSAPR and CAIR, the regulation of hazardous air pollutants from coal- and oil-fired electric generating facilities under MATS, and regulation of GHG emissions, in addition to NOVs issued to Generation and ComEd for alleged violations of the Clean Air Act.

Water Quality

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. Certain 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 22 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.

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. EPA 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. EPA 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, Maryland and Pennsylvania, have also enacted statutes that contain provisions substantially similar to CERCLA. In addition, RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

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

See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding solid and hazardous waste regulation and legislation.

Environmental Remediation

ComEd s, PECO s and BGE s environmental liabilities primarily arise from contamination at former MGP sites. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, have an on-going process to recover environmental remediation costs of the MGP sites through a provision within customer rates. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. The amount to be expended in 2014 at Exelon for compliance with environmental remediation related to contamination at former MGP sites is expected to total $40 million, consisting of $33 million, $6 million and $1 million at ComEd, PECO and BGE, respectively.

Generation s environmental liabilities primarily arise from contamination at current and former generation and waste storage facilities. As of December 31, 2013, Generation has established an appropriate liability to comply with environmental remediation requirements including contamination attributable to low level radioactive residues at a storage and reprocessing facility named Latty Avenue, and at a disposal facility named West Lake Landfill, both near St. Louis, Missouri related to operations conducted by Cotter Corporation, a former ComEd subsidiary.

In addition, Generation, ComEd, PECO and BGE may be required to make significant additional expenditures not presently determinable for other environmental remediation costs.

See Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants environmental remediation efforts and related impacts to the Registrants results of operations, cash flows and financial position.

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, and as reported by the Intergovernmental Panel on Climate Change in their Fifth Assessment Report Summary for Policy Makers issues September 2013. 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 combustion of fossil fuels represent the majority of Exelon s direct GHG emissions in 2013, although only a small portion of Exelon s electric supply is from fossil generating plants. Other GHG emission sources at Exelon include natural gas (methane) leakage on the natural gas systems, sulfur hexafluoride (SF_6) leakage in its electric transmission and distribution operations and refrigerant leakage from its chilling and cooling equipment as well as fossil fuel combustion in its motor vehicles and usage of electricity at its facilities. Despite its focus on low-carbon generation, 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 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 Federal, regional and state levels.

International Climate Change Regulation. At the international level, the United States has not yet ratified the United Nations Kyoto Protocol, which was extended at the 2012 meeting of the United Nations Framework on Climate Change Conference of the Parties (COP 18). The Kyoto Protocol now requires participating developed countries to cap GHG emissions at certain levels until 2020, when the new global agreement on emissions reduction is scheduled to become effective. This new global agreement for GHG emissions reductions was agreed to only in concept during the COP18, with a timeline for establishing the global targets by 2015. On November 22, 2013, at the 2013 COP 19 held in Warsaw, Poland, participating countries further agreed to provide their intended nationally determined contributions by the first quarter of 2015 in preparation for formally setting global target in 2015. The other major issues discussed at COP 19 were demands from developing countries for increased climate finance, and for a new mechanism to help especially vulnerable nations cope with unavoidable loss and damage resulting from climate change. Developed countries, which had previously promised to mobilize a total of $100 billion a year by 2020, refused to set a quantified interim goal for ramping up climate finance.

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, including the enactment of federal climate change legislation. It is highly uncertain whether Federal legislation to reduce GHG emissions will be enacted. If such legislation is adopted, Exelon may incur costs either to further limit or offset the GHG emissions from its operations or to procure emission allowances or credits. In June 2013, the White House released the President s Climate Action Plan which consists of a wide variety of executive actions targeting GHG reductions, preparing for the impacts of climate change and showing leadership internationally; but the plan did not directly trigger any new requirements or legislative action.

The U.S. EPA is addressing the issue of carbon dioxide (CO2) emissions regulation for new and existing electric generating units through the New Source Performance Standards (NSPS) under Section 111 of the Clean Air Act. Pursuant to President Obama s June 25, 2013 memorandum to U.S. EPA, the Agency re-proposed a Section 111(b) regulation for new units in September 2013 that may result in material costs of compliance for CO2 emissions for new fossil-fuel electric generating units, particularly coal-fired units. Under the President s memorandum, the U.S. EPA is also required to propose a Section 111(d) rule no later than June 1, 2014 to establish CO2 emission regulations for existing stationary sources.

Regional and State Climate Change Legislation and Regulation. After a two-year program review, the nine northeast and mid-Atlantic states currently participating in the Regional Greenhouse Gas Reduction Initiative (RGGI) released an updated RGGI Model Rule and Program Review Recommendations Summary on February 7, 2013. Under the updated RGGI program, which must be approved pursuant to the applicable legislative and/or regulatory process in each RGGI state, the regional RGGI CO2 budget would be reduced, starting in 2014, from its current 165 million ton level to 91 million tons, with a 2.5 percent reduction in the cap level each year between 2015-2020. Included in the new program are provisions for cost containment reserve (CCR) allowances, which will become available if the total demand for allowances, above the CCR trigger price, exceeds the number of CO2 allowances available for purchase at auction. (CCR trigger prices are $4 in 2014, $6 in 2015, $8 in 2016 and $10 in 2017, rising 2.5 percent thereafter to account for inflation). Such an outcome could put modest upward pressure on wholesale power prices; however, the specifics are currently uncertain.

At the state level, the Illinois Climate Change Advisory Group, created by Executive Order 2006-11 on October 5, 2006, made its final recommendations on September 6, 2007 to meet the Governor s GHG reduction goals. At this time, the only requirements imposed by the state of Illinois are the energy efficiency and renewable portfolio standards in the Illinois Power Act that apply to ComEd.

On December 18, 2009, Pennsylvania issued the state s final Climate Change Action Plan. The plan sets as a target a 30 percent reduction in GHG emissions by 2020. The Climate Change Advisory Committee continues to meet quarterly to review Climate Action Work Plans for the residential, commercial and industrial sectors. The Climate Change Action Plan does not impose any requirements on Generation or PECO at this time.

The Maryland Commission on Climate Change released its climate action plan on August 27, 2008, recommending that the state begin implementing 42 greenhouse gas reduction strategies. One of the Plan s policy recommendations, to adopt science-based regulatory goals to reduce Maryland s GHG emissions, was realized with the passage of the Greenhouse Gas Emissions Reduction Act of 2009 (GGRA). The law requires Maryland to reduce its GHG emissions by 25 percent below 2006 levels by 2020. It directed the MDE to work with other state agencies to prepare an implementation plan to meet this goal. The implementation plan was published in October of 2013. Maryland targeted electricity consumption reduction goals required under the Empower Maryland program, and mandatory State participation in the recently updated and enhanced RGGI Program are listed as that sector s contribution in the plan. The plan also advocates raising the renewable portfolio standard requirement from 22% by 2022 to 25% by 2022.

Exelon s Voluntary Climate Change Efforts. In a world increasingly concerned about global climate change and regulatory action to reduce GHG, Exelon s low-carbon generating fleet is seen by management as a competitive advantage. Exelon remains one of the largest, lowest carbon electric generators in the United States: nuclear for base load, natural gas for marginal and peak demand, hydro and pumped storage, and supplemental wind and solar renewables. As further legislation and regulation imposing requirements on emissions of GHG and air pollutants are promulgated, Exelon s low-carbon, low-emission generation fleet will position the company to benefit from its comparative advantage over other generation fleets.

With the announcement in 2008 of Exelon 2020, Exelon set a voluntary goal to reduce, offset or displace more than 15.7 million metric tonnes of GHG emissions per year by 2020. Exelon updated that goal in 2012 following the Constellation merger to account for the integration of former Constellation GHG goals. The updated Exelon 2020 goal is to reduce, offset or displace more than 17.5 million metric tonnes of GHG emissions by 2020. The Exelon 2020 goal encompasses three broad areas of focus: reducing or offsetting Exelon s own carbon footprint (with the year the asset/operations were acquired by Exelon as the baseline), helping customers and communities reduce their GHG emissions, and offering more low-carbon electricity in the marketplace. Exelon has been maintaining strong performance towards achieving the goal and anticipates reaching the 17.5 million tons of annual abatement well before 2020.

Renewable and Alternative Energy Portfolio Standards

Thirty-nine states and the District of Columbia have adopted some form of RPS requirement. As previously described, Illinois, Pennsylvania and Maryland 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, 2013, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. See Note 3 and Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

The AEPS Act became effective for PECO on January 1, 2011, following the expiration of PECO s transition period. During 2013, PECO was required to supply approximately 4.0% 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) through May 31, 2013 and subsequently 4.5% beginning June 1, 2013 and continuing through May 31, 2014. PECO was also required to supply 6.2% of electric energy generated from Tier II (including waste coal, demand-side management, large-scale hydropower, municipal solid waste, generation of electricity utilizing wood and 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.

Section 7-703 of the Public Utilities Article in Maryland sets forth the RPS requirement, which applies to all retail electricity sales in Maryland by electricity suppliers. The RPS requirement requires that suppliers obtain a specified percentage of the electricity it sells from Tier 1 sources (solar, wind, biomass, methane, geothermal, ocean, fuel cell, small hydroelectric, and poultry litter) and Tier 2 sources (hydroelectric, other than pump storage generation, and waste-to-energy). The RPS requirement began in 2006, requiring that suppliers procure 1.0% and 2.5% from Tier 1 and Tier 2 sources, respectively, escalating in 2022 to 22.0% from Tier 1 sources, including at least 2.0% from solar energy, and a phase out of Tier 2 resource options by 2022. In 2013, 8.2% was required from Tier 1 renewable sources, including at least 0.25% derived from solar energy, and 2.5% from Tier 2 renewable sources. The wholesale suppliers that supply power to the state s utilities through the SOS procurement auctions have the obligation, by contract with those utilities, to comply with and provide its proportional share of the RPS requirements.

Similar to ComEd, PECO and BGE, Generation s retail electric business must source a portion of the electric load it serves in many of the states in which it does business from renewable resources or approved equivalents such as RECs. 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 wind, solar, hydroelectric and landfill gas.

See Note 3 and Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

Executive Officers of the Registrants as of February 13, 2014

Exelon

Name	Age	Position	Period
Crane, Christopher M.	55	Chief Executive Officer, Exelon;	2012 - Present
		Chairman, ComEd, PECO & BGE	2012 - Present
		President, Exelon	2008 - Present
		President, Generation	2008 - 2013
		Chief Operating Officer, Exelon	2008 - 2012
		Chief Operating Officer, Generation	2007 - 2010
Cornew, Kenneth W.	48	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
O Brien, Denis P.	53	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2012 - Present
		Vice Chairman, ComEd, PECO, BGE	2012 - Present
		Chief Executive Officer, PECO; Executive Vice President, Exelon	2007 - 2012
		President and Director, PECO	2003 - 2012

Name	Age	Position	Period
Pramaggiore, Anne R.	55	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
		Executive Vice President, Customer Operations, Regulatory and External Affairs, ComEd	2007 - 2009
Adams, Craig L.	61	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
DeFontes Jr., Kenneth W.	63	President and Chief Executive Officer, BGE	2004 - Present(a)
		Senior Vice President, Constellation Energy	2004 - 2012
Gillis, Ruth Ann M.	59	Executive Vice President, Exelon	2008 - Present
		Chief Administrative Officer, Exelon	2010 - Present
		President, Exelon Business Services Company	2005 - Present
		Chief Diversity Officer, Exelon	2009 - 2012
Von Hoene Jr., William A.	60	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
		Executive Vice President, Finance and Legal, Exelon	2009 - 2012
		Executive Vice President and General Counsel, Exelon	2008 - 2009
		Senior Vice President, Exelon Business Services Company	2004 - 2009
Thayer, Jonathan W.	42	Executive Vice President and Chief Financial Officer, Exelon	2012 - Present
		Senior Vice President and Chief Financial Officer, Constellation Energy; Treasurer, Constellation Energy	2008 - 2012
Aliabadi, Paymon	51	Executive Vice President and Chief Risk Officer, Exelon	2013 - Present
		Managing Director, Gleam Capital Management	2012 - 2013
		Principal and Managing Director, Gunvor International	2009 - 2011
		Chief Executive Officer, Essent Trading International	2004 - 2009
DesParte, Duane M.	50	Senior Vice President and Corporate Controller, Exelon	2008 - Present

Generation

Name	Age	Position	Period
Cornew, Kenneth W.	48	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012

Name	Age	Position	Period
Pacilio, Michael J.	53	President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	2010 - Present
		Chief Operating Officer, Exelon Nuclear	2007 - 2010
Nigro, Joseph	49	Executive Vice President, Exelon; Chief Executive Officer, Constellation	2013 - Present
		Senior Vice President, Portfolio Management and Strategy	2012 - 2013
		Vice President, Structuring and Portfolio Management, Exelon Power Team	2010 - 2012
DeGregorio, Ronald	51	Senior Vice President, Generation; President, Exelon Power	2012 - Present
		Chief Integration Officer, Exelon	2011 - 2012
		Chief Operating Officer, Exelon Transmission Company	2010 - 2011
		Senior Vice President, Mid-Atlantic Operations, Exelon Nuclear	2007 - 2010
Wright, Bryan P.	47	Senior Vice President and Chief Financial Officer, Generation	2013 - Present
		Senior Vice President, Corporate Finance, Exelon	2012 - 2013
		Chief Accounting Officer, Constellation Energy	2009 - 2012
		Vice President and Controller, Constellation Energy	2008 - 2012
Aiken, Robert	47	Vice President and Controller, Generation	2012 - Present
		Executive Director and Assistant Controller, Constellation	2011 - 2012
		Executive Director of Operational Accounting, Constellation Energy Commodities Group	2009 - 2011
		Vice President of International Accounting, Constellation Energy Commodities Group	2007 - 2009

ComEd

Name	Age	Position	Period
Pramaggiore, Anne R.	55	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
		Executive Vice President, Customer Operations, Regulatory and External Affairs, ComEd	2007 - 2009
Donnelly, Terence R.	53	Executive Vice President and Chief Operating Officer, ComEd	2012 - Present
		Executive Vice President, Operations, ComEd	2009 - 2012
		Senior Vice President, Transmission and Distribution, ComEd	2007 - 2009
Trpik Jr., Joseph R.	44	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 - Present
		Vice President & Assistant Corporate Controller, Exelon Business Services Company	2007 - 2009
		Vice President and Assistant Corporate Controller, Exelon	2004 - 2009

Name	Age	Position	Period
Jensen, Val	58	Senior Vice President, Customer Operations, ComEd	2012 - Present
		Vice President, Marketing and Environmental Programs, ComEd	2008 - 2012
O Neill, Thomas S.	51	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2010 - Present
		Senior Vice President, Exelon	2009 - 2010
		Senior Vice President, New Business Development, Generation; Senior Vice President, New Business Development, Exelon	2009 - 2009
		Vice President, New Plant Development, Generation	2007 - 2009
Marquez Jr., Fidel	52	Senior Vice President, Governmental and External Affairs, Exelon	2012 - Present
		Senior Vice President, Customer Operations, ComEd	2009 - 2012
		Vice President of External Affairs and Large Customer Services, ComEd	2007 - 2009
Brookins, Kevin B.	52	Senior Vice President, Strategy & Administration, ComEd	2012 - Present
		Vice President, Operational Strategy and Business Intelligence, ComEd	2010 - 2012
		Vice President, Distribution System Operations, ComEd	2008 - 2010
Anthony, J. Tyler	49	Senior Vice President, Distribution Operations, ComEd	2010 - Present
		Vice President, Transmission and Substations, ComEd	2007 - 2010
Kozel, Gerald J.	41	Vice President, Controller, ComEd	2013 - Present
		Assistant Corporate Controller, Exelon	2012 - 2013
		Director of Financial Reporting and Analysis, Exelon	2009 - 2012
		Manager of Accounting, ComEd	2008 - 2009

PECO

Name	Age	Position	Period
Adams, Craig L.	61	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Barnett, Phillip S.	50	Senior Vice President and Chief Financial Officer, PECO	2007 - Present
		Treasurer, PECO	2012 - Present
Innocenzo, Michael A.	48	Senior Vice President and Chief Operations Officer, PECO	2012 - Present
		Vice President, Distribution System Operations and Smart Grid/Smart Meter, PECO	2010 - 2012
		Vice President, Distribution System Operations	2007 - 2010

Name	Age	Position	Period
Webster Jr., Richard G.	52	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
		Director of Rates and Regulatory Affairs	2007 - 2012
Murphy, Elizabeth A.	54	Vice President, Governmental and External Affairs, PECO	2012 - Present
		Director, Governmental & External Affairs, PECO	2007 - 2012
Jiruska, Frank J.	53	Vice President, Customer Operations, PECO	2013 - Present
Diaz Jr., Romulo L.	67	Vice President and General Counsel, PECO	2012 - Present
		Vice President, Governmental and External Affairs, PECO	2009 - 2012
		Associate General Counsel, Exelon	2008 - 2009
Bailey, Scott A.	37	Vice President and Controller, PECO	2012 - Present
		Assistant Controller, Generation	2011 - 2012
		Director of Accounting, Power Team	2007 - 2011

BGE

Name	Age	Position	Period
DeFontes Jr., Kenneth W.	63	President and Chief Executive Officer, BGE	2004 - Present(a)
		Senior Vice President, Constellation Energy	2004 - 2012
Woerner, Stephen J.	46	Chief Operating Officer, BGE	2012 - Present
		Senior Vice President, BGE	2009 - Present
		Vice President and Chief Integration Officer, Constellation Energy	2011 - 2012
		Vice President and Chief Information Officer, Constellation Energy	2010 - 2011
		Vice President, Transformation, Constellation Energy	2009 - 2010
		Senior Vice President, Gas and Electric Operations and Planning, BGE	2007 - 2009
Khouzami, Carim V.	38	Senior Vice President, Chief Financial Officer and Treasurer, BGE	2013 - Present
		Vice President, Chief Financial Officer and Treasurer, BGE	2011 - 2013
		Executive Director, Investor Relations, Constellation Energy	2009 - 2011
		Director, Corporate Strategy and Development, Constellation Energy	2008 - 2009
Butler, Calvin	44	Senior Vice President, Regulatory and External Affairs, BGE	2013 - Present(a)
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
		Senior Vice President, Human Resources, Exelon	2010 - 2011
		Senior Vice President, Corporate Affairs, ComEd	2009 - 2010

Name	Age	Position	Period
Case, Mark D.	52	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
		Senior Vice President, Strategy and Regulatory Affairs, BGE	2007 - 2012
Dodson, Carol A.	49	Vice President, Customer Operations, BGE	2013 - Present
		Chief Customer Officer, BGE	2013 - Present
		Vice President, Utility Oversight, BSC	2012 - 2013
		Vice President, Engineering and Project Management, BGE	2012 - 2012
		Senior Vice President, Asset Management Services, BGE	2009 - 2012
Gahagan, Daniel P.	60	Vice President and General Counsel, BGE	2007 - Present
Vahos, David M.	41	Vice President and Controller, BGE	2012 - Present
		Executive Director, Audit, Constellation	2010 - 2012
		Director, Finance, BGE	2006 - 2010

(a) On February 12, 2014, Kenneth W. DeFontes Jr., President and Chief Executive Officer at BGE announced his retirement from BGE on February 28, 2014. Effective March 1, 2014, Calvin G. Butler Jr. will become Chief Executive Officer of BGE and an executive officer of Exelon and Stephen J. Woerner will become President and continue as Chief Operating Officer of BGE.

ITEM 1A. RISK FACTORS

Each of the Registrants operates in a market and regulatory environment that poses significant risks, many of which are beyond the Registrant s control. Management of each Registrant regularly meets with the Chief Risk Officer and the RMC, which comprises officers of the Registrants, to identify and evaluate the most significant risks of the Registrants businesses, and the appropriate steps to manage and mitigate those risks. The Chief Risk Officer and senior executives of the Registrants discuss those risks with the finance and risk committee and audit committees of the Exelon board of directors and the ComEd, PECO and BGE boards of directors. In addition, the generation oversight committee of the Exelon board of directors evaluates risks related to the generation business. The risk factors discussed below may adversely affect one or more of the Registrants results of operations and cash flows and the market prices of their publicly traded securities. Each of the Registrants has disclosed the known material risks that affect its business at this time. However, there may be further risks and uncertainties that are not presently known or that are not currently believed by a Registrant to be material that may adversely affect its performance or financial condition in the future.

The Registrants most significant risks arise as a consequence of: (1) Generation s position as a predominantly nuclear generator selling power into competitive energy markets with a concentration in select regions, and (2) the role of ComEd, PECO and BGE as operators of electric transmission and distribution systems in three of the largest metropolitan areas in the United States. The Registrants major risks fall primarily under the following categories:

Market and Financial Risks. Exelon s and Generation s market and financial risks include the risk of price fluctuations in the power markets. 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 prices that Generation can obtain for the output of its power plants, (2) the rate of expansion of subsidized low-carbon generation in the markets in which Generation s output is sold, (3) the effects on energy demand of factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel.

Regulatory and Legislative Risks. The Registrants regulatory and legislative risks include changes to the laws and regulations that govern competitive markets and utility cost recovery, and that drive environmental policy. In particular, Exelon s and Generation s financial performance may be adversely affected by changes that could affect Generation s ability to sell power into the competitive wholesale power markets at market-based prices. In addition, potential regulation and legislation regarding climate change and renewable portfolio standards could increase the pace of development of wind energy facilities, which could put downward pressure in some markets on wholesale market prices for electricity from Generation s nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation s nuclear assets under a carbon constrained regulatory regime that might exist in the future. Also, regulatory actions in Illinois, Pennsylvania or Maryland could materially lower returns for ComEd, PECO and BGE, respectively.

Operational Risks. The Registrants operational risks include those risks inherent in running the nation s largest fleet of nuclear power reactors and large electric and gas distribution systems. The safe and effective operation of the nuclear facilities and the ability to effectively manage the associated decommissioning obligations as well as the ability to maintain the availability, reliability and safety of its energy delivery systems are fundamental to Exelon s ability to protect and grow shareholder value. Additionally, the operating costs of ComEd, PECO and BGE, and the opinions of customers and regulators of ComEd, PECO and BGE, are affected by those companies ability to maintain the reliability and safety of their energy delivery systems.

Risks Related to the Merger with Constellation and the Pending Master Agreement between Generation and CENG. As a result of the merger with Constellation that closed on March 12, 2012, Exelon may encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals from the July 29, 2013 Master Agreement between Exelon, Generation and subsidiaries of Generation with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG. Exelon and Generation are subject to the risks that integration of CENG s nuclear fleet may not achieve anticipated results, and that Exelon and Generation may not be able to fully integrate the operations of CENG in the manner expected.

A discussion of each of these risk categories and other risk factors is included below.

Market and Financial Risks

Generation is exposed to depressed prices in the wholesale and retail power markets, which may negatively affect its results of operations and cash flows. (Exelon and Generation)

Generation is exposed to commodity price risk for the unhedged portion of its electricity generation supply portfolio. As such, Generation s earnings and cash flows are therefore subject to variability as spot and forward market prices in the markets in which it operates rise and fall.

Price of Fuels: The spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Thus, the market price of power is affected by the market price of the marginal fuel used to generate the electricity unit. Often, the next unit of electricity will be supplied from generating stations fueled by fossil fuels. Consequently, changes in the market price of fossil fuels often result in comparable changes to the market price of power. For example, the use of new technologies to recover natural gas from shale deposits has increased natural gas supply and reserves, placing downward pressure on natural gas prices and, therefore, on power prices. The continued addition of supply from new alternative generation resources, such as wind and solar, whether mandated through RPS or otherwise subsidized or encouraged through climate legislation or regulation, may displace a higher marginal cost plant, further reducing power prices. In addition, further delay or elimination of EPA air quality regulations could prolong the duration for which the cost of pollution from fossil fuel generation is not factored into market prices.

Demand and Supply: The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. Unfavorable economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs can each depress demand. The result is that higher-cost generating resources do not run as frequently, putting downward pressure on electricity market prices. The continued tepid economic environment and growing energy efficiency and demand response initiatives have limited the demand for electricity in Generation s markets. In addition, in some markets, the supply of electricity through wind or solar generation, when combined with other base-load generation such as nuclear, may often exceed demand during some hours of the day, resulting in loss of revenue for base-load generating plants. The risk of increased supply in excess of demand is heightened by continued or increased RPS mandates or other subsidies, including ITCs and PTCs.

Retail Competition: Generation s retail operations compete for customers in a competitive environment, which affects the margins that Generation can earn and the volumes that it is able to serve. In an environment of sustained low natural gas and power prices and low market volatility, retail competitors can aggressively pursue market share because the barriers to entry can be low and wholesale generators (including Generation) use their retail operations to hedge generation output. Increased or more aggressive competition can adversely affect overall gross margins and profitability in Generation s retail operations.

Sustained low market prices or depressed demand and over-supply could adversely affect Exelon s and Generation s results of operations and cash flows, and such impacts could be emphasized given Generation s concentration of base-load electric generating capacity within primarily two geographic market regions, namely the Midwest and the Mid-Atlantic. These impacts could adversely affect Exelon s and Generation s ability to fund other discretionary uses of cash such as growth projects or to pay dividends. In addition, such conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Exelon s and Generation s results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs which may be offset in whole or in part by reduced operating and maintenance expenses. A slow recovery in market conditions could result in a prolonged depression of or further decline in commodity prices, including low forward natural gas and power prices and low market volatility, which could also adversely affect Exelon s and Generation s results of operations, cash flows and financial position.

In addition to price fluctuations, Generation is exposed to other risks in the power markets that are beyond its control and may negatively affect its results of operations. (Exelon and Generation)

Credit Risk. In the bilateral markets, Generation is exposed to the risk that counterparties that owe Generation money, or are obligated to purchase energy or fuel from Generation, will not perform under their obligations for operational or financial reasons. In the event the counterparties to these arrangements fail to perform, Generation might be forced to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, to the extent of amounts, if any, already paid to the counterparties. In the spot markets, Generation is exposed to risk as a result of default sharing mechanisms that exist within certain markets, primarily RTOs and ISOs, the purpose of which is to spread such risk across all market participants. Generation is also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties. In addition, Generation s retail sales subject it to credit risk through competitive electricity and natural gas supply activities to serve commercial and industrial companies, governmental entities and residential customers. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that may be incurred due to the nonpayment of a customer s account balance, as well as the loss from the resale of energy previously committed to serve the customer.

Unstable Markets. The wholesale spot markets remain evolving markets that vary from region to region and are still developing practices and procedures. Problems in or the failure of any of these markets could adversely affect Generation s business. In addition, a significant decrease in market participation could affect market liquidity and have a detrimental effect on market stability.

The Registrants are potentially exposed to emerging technologies that may over time affect or transform the energy industry, including technologies related to energy generation, distribution and consumption. (Exelon, Generation, ComEd, PECO and BGE)

Some of these technologies include, but are not limited to further shale gas development or sources, cost-effective renewable energy technologies, broad consumer adoption of electric vehicles and energy storage devices. Such developments could lower the price of energy, could affect energy deliveries as customer-owned generation becomes more cost-effective, could require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy. Each of these factors could materially affect the Registrants results of operations, financial position, and cash flows through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Market performance and other factors may decrease the value of NDT funds and employee benefit plan assets and increase the related employee benefit plan obligations, which then could require significant additional funding. (Exelon, Generation, ComEd, PECO and BGE)

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy may adversely affect the value of the investments held within Generation s NDTs and Exelon s employee benefit plan trusts. The Registrants have significant obligations in these areas and Exelon and Generation hold substantial assets in these trusts to meet those obligations. The asset values are subject to market fluctuations and will yield uncertain returns, which may fall below the Registrants projected return rates. A decline in the market value of the NDT fund investments may increase Generation s funding requirements to decommission its nuclear plants. A decline in the market value of the pension and other postretirement benefit plan assets will increase the funding requirements associated with Exelon s pension and other postretirement benefit plan obligations. Additionally, Exelon s pension and other postretirement benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements may also increase the costs and funding requirements of the obligations related to the pension and other postretirement benefit plans. If future increases in pension and other postretirement costs as a result of reduced plan assets or other factors cannot be recovered, or cannot be recovered in a timely manner, from ComEd, PECO and BGE customers, the results of operations and financial positions of ComEd, PECO and BGE could be negatively affected. Ultimately, if the Registrants are unable to manage the investments with the NDT funds and benefit plan assets, and unable to manage the related benefit plan liabilities, their results of operations, cash flows and financial positions could be negatively affected.

Unstable capital and credit markets and increased volatility in commodity markets may adversely affect the Registrants businesses in several ways, including the availability and cost of short-term funds for liquidity requirements, the Registrants ability to meet long-term commitments, Generation s ability to hedge effectively its generation portfolio, and the competitiveness and liquidity of energy markets; each could adversely affect the Registrants financial condition, results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet their financial commitments and short-term liquidity needs if internal funds are not available from the Registrants respective operations. Disruptions in the capital and credit markets in the United States or abroad can adversely affect the Registrants ability to access the capital markets or draw on their respective bank revolving credit facilities. The Registrants access to funds under their credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments. Those banks may not be able to meet their funding commitments to the Registrants if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from the Registrants and other borrowers within a short period of time. The inability to access capital markets or credit facilities, and longer term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, changes to Generation s hedging strategy in order to reduce collateral-posting requirements, or a reduction in dividend payments or other discretionary uses of cash.

In addition, the Registrants have exposure to worldwide financial markets, including Europe. 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, 2013, approximately 30%, or $2.5 billion, of the Registrants available credit facilities were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.6 billion was available as of December 31, 2013. There were no borrowings under the Registrants credit facilities as of December 31, 2013. See Note 13 of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

The strength and depth of competition in competitive energy markets depend heavily on active participation by multiple trading parties, which could be adversely affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that may affect participants in commodities transactions. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to the respective businesses of the Registrants. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace market structures with other mechanisms for the sale of power, including the requirement of long-term contracts, which could have a material adverse effect on Exelon s and Generation s results of operations and cash flows.

If any of the Registrants were to experience a downgrade in its credit ratings to below investment grade or otherwise fail to satisfy the credit standards in its agreements with its trading counterparties, it would be required to provide significant amounts of collateral under its agreements with counterparties and could experience higher borrowing costs. (Exelon, Generation, ComEd, PECO and BGE)

Generation s business is subject to credit quality standards that may require market participants to post collateral for their obligations. If Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating) or otherwise fail to satisfy the credit standards of trading counterparties, it would be required under its hedging arrangements to provide collateral in the form of letters of credit or cash, which may have a material adverse effect upon its liquidity. The amount of collateral required to be provided by Generation at any point in time is dependent on a variety of factors, including (1) the notional amount of the applicable hedge, (2) the nature of counterparty and related agreements, and (3) changes in power or other commodity prices. In addition, if Generation were downgraded, it could experience higher borrowing costs as a result of the downgrade. Generation could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the power generation industry in general, or Generation in particular, has deteriorated. Changes in ratings methodologies by the credit rating agencies could also have a negative impact on the ratings of Generation.

ComEd s operating agreement with PJM contains collateral provisions that are affected by its credit rating and market prices. If certain wholesale market conditions exist and ComEd were to lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required under the PJM operating agreement to provide collateral in the forms of letters of credit or cash, which may have a material adverse effect upon its liquidity. Collateral posting will generally increase as market prices rise and decrease as market prices fall. Given the relationship to forward market prices, contract collateral requirements can be volatile. In addition, if ComEd were downgraded, it could experience higher borrowing costs as a result of the downgrade.

PECO s and BGE s operating agreements with PJM and their natural gas procurement contracts contain collateral provisions that are affected by their credit ratings. If certain wholesale market conditions exist and PECO and BGE were to lose their investment grade credit ratings (based on their senior unsecured debt ratings), they would be required to provide collateral in the form of letters of credit or cash, which may have material adverse effects upon their liquidity. PECO s and BGE s collateral requirements relating to their natural gas supply contracts are a function of market prices. Collateral posting requirements for PECO and BGE with respect to these contracts will generally increase as forward market prices fall and decrease as forward market prices rise. Given the relationship to forward market prices, contract collateral requirements can be volatile. In addition, if PECO or BGE were downgraded, they could experience higher borrowing costs as a result of the downgrade.

ComEd, PECO or BGE could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the utility industry in general, or ComEd, PECO, or BGE in particular, has deteriorated. ComEd, PECO or BGE could experience a downgrade if the current regulatory environments in Illinois, Pennsylvania or Maryland, respectively, become less predictable by materially lowering returns for utilities in the applicable state or adopting other measures to mitigate higher electricity prices. Additionally, the ratings for ComEd, PECO or BGE could be downgraded if their financial results are weakened from current levels due to weaker operating performance or due to a failure to properly manage their capital structure. In addition, changes in ratings methodologies by the agencies could also have a negative impact on the ratings of ComEd, PECO or BGE.

ComEd, PECO and BGE conduct their respective businesses and operate under governance models and other arrangements and procedures intended to assure that ComEd, PECO and BGE are treated as separate, independent companies, distinct from Exelon and other Exelon subsidiaries in order to isolate ComEd, PECO and BGE from Exelon and other Exelon subsidiaries in the event of financial difficulty at Exelon or another Exelon subsidiary. These measures (commonly referred to as ringfencing) may help avoid or limit a downgrade in the credit ratings of ComEd, PECO and BGE in the event of a reduction in the credit rating of Exelon. Despite these ringfencing measures, the credit ratings of ComEd, PECO or BGE could remain linked, to some degree, to the credit ratings of Exelon. Consequently, a reduction in the credit rating of Exelon could result in a reduction of the credit rating of ComEd, PECO or BGE, or all three. A reduction in the credit rating of ComEd, PECO or BGE could have a material adverse effect on ComEd, PECO or BGE, respectively.

See Liquidity and Capital Resources Recent Market Conditions and Security Ratings for further information regarding the potential impacts of credit downgrades on the Registrants cash flows.

Generation s financial performance may be negatively affected by price volatility, availability and other risk factors associated with the procurement of nuclear and fossil fuel. (Exelon and Generation)

Generation depends on nuclear fuel and fossil fuels to operate its generating facilities. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. Coal, natural gas and oil are procured for generating plants through annual, short-term and spot-market purchases. The supply markets for nuclear fuel, coal, natural gas and oil are subject to price fluctuations, availability restrictions and counterparty default that may negatively affect the results of operations for Generation.

Generation s risk management policies cannot fully eliminate the risk associated with its commodity trading activities. (Exelon and Generation)

Generation s asset-based power position as well as its power marketing, fuel procurement and other commodity trading activities expose Generation to risks of commodity price movements. Generation attempts to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when its policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations may be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, Generation cannot predict the impact that its commodity trading activities and risk management decisions may have on its business, operating results, cash flows or financial position.

Generation buys and sells energy and other products in the wholesale markets and enters into financial contracts to manage risk and hedge various positions in Generation s power generation portfolio. The proportion of hedged positions in its power generation portfolio may cause volatility in Generation s future results of operations.

Financial performance and load requirements may be adversely affected if Generation is unable to effectively manage its power portfolio. (Exelon and Generation)

A significant portion of Generation s power portfolio is used to provide power under procurement contracts with ComEd, PECO, BGE and other customers. To the extent portions of the power portfolio are not needed for that purpose, Generation s wholesale output is sold in the wholesale power markets. To the extent its power portfolio is not sufficient to meet the requirements of its customers under the related agreements, Generation must purchase power in the wholesale power markets. Generation s financial results may be negatively affected if it is unable to cost-effectively meet the load requirements of its customers, manage its power portfolio and effectively address the changes in the wholesale power markets.

Challenges to tax positions taken by the Registrants as well as tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions, could negatively impact the Registrants results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

Corporate Tax Reform. There exists the potential for comprehensive tax reform in the United States that may significantly change the tax rules applicable to U.S. domiciled corporations. Exelon cannot assess what the overall effect of such potential legislation would be on its results of operations and cash flows.

1999 sale of fossil generating assets. The IRS has challenged Exelon s 1999 tax position on its like-kind exchange transaction. Exelon and the IRS failed to reach a settlement on the like-kind exchange position and Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the like-kind exchange position. The litigation could take three to five years including appeals, if necessary.

As of December 31, 2013, if the IRS is successful in its challenge to the like-kind exchange position, Exelon s potential cash outflow, including tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $840 million, of which approximately $305 million would be attributable to ComEd after consideration of Exelon s agreement to hold ComEd harmless. In addition to attempting to impose tax on the like-kind exchange position, the IRS has asserted penalties for a substantial understatement of tax, which could result in an after-tax charge of $87 million to Exelon s and ComEd s results of operations should the IRS prevail in asserting the penalties. The timing effects of the final resolution of the like-kind exchange matter are unknown. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information.

Tax reserves and the recoverability of deferred tax assets. The Registrants are required to make judgments in order to estimate their obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes and ongoing appeals issues related to these tax matters. These judgments include reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by the tax authorities. The Registrants also estimate their ability to utilize tax benefits, including those in the form of carryforwards and tax credits. See Notes 1 and 14 of the Combined Notes to Consolidated Financial Statements for additional information.

Increases in customer rates and the impact of economic downturns may lead to greater expense for uncollectible customer balances. Additionally, increased rates could lead to decreased volumes delivered. Both of these factors may decrease Generation s, ComEd s, PECO s and BGE s results from operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

ComEd s, PECO s and BGE s current procurement plans include purchasing power through contracted suppliers and in the spot market. ComEd s and PECO s costs of purchased power are charged to customers without a return or profit component. BGE s SOS rates charged to customers recover BGE s wholesale power supply costs and include an administrative fee which includes a shareholder return component and an incremental cost component. For PECO, purchased natural gas costs are charged to customers with no return or profit component. For BGE, purchased natural gas costs are charged to customers using a MBR mechanism that compares the actual cost of gas to a market index. The difference between the actual cost and the market index is shared equally between shareholders and customers. Purchased power and natural gas prices fluctuate based on their relevant supply and demand. Significantly higher rates related to purchased power and natural gas can result in declines in customer usage, lower revenues and potentially additional uncollectible accounts expense for ComEd, PECO and BGE. In addition, any challenges by the regulators or ComEd, PECO and BGE as to the recoverability of these costs could have a material effect on the Registrants results of operations and cash flows. Also, ComEd s, PECO s and BGE s cash flows can be affected by differences between the time period when electricity and natural gas are purchased and the ultimate recovery from customers.

Further, the impacts of economic downturns on ComEd, PECO and BGE customers and purchased natural gas costs for PECO and BGE customers, such as unemployment for residential customers and less demand for products and services provided by commercial and industrial customers, and the related regulatory limitations on residential service terminations, may result in an increase in the number of uncollectible customer balances, which would negatively impact ComEd s, PECO s and BGE s results from operations and cash flows. Generation s customer supply activities face economic downturn risks similar to Exelon s utility businesses, such as lower volumes sold and increased expense for uncollectible customer balances. As Generation increases its customer supply footprint, economic downturn impacts could negatively affect Generation s results from operations and cash flows. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for further discussion of the Registrants credit risk.

The effects of weather may impact the Registrants results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Moderate temperatures adversely affect the usage of energy and resulting revenues at ComEd and PECO. Due to revenue decoupling, BGE recognizes revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes are for a billing period, and is not affected by actual weather with the exception of major storms. Extreme weather conditions or damage resulting from storms may stress ComEd s, PECO s and BGE s transmission and distribution systems, communication systems and technology, resulting in increased maintenance and capital costs and limiting each company s ability to meet peak customer demand. These extreme conditions may have detrimental effects on ComEd s, PECO s and BGE s results of operations and cash flows. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and may make period comparisons less relevant.

Generation s operations are also affected by weather, which affects demand for electricity as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, Generation may require greater resources to meet its contractual commitments. Extreme weather conditions or storms may affect the availability of generation and its transmission, limiting Generation s ability to source or send power to where it is sold. In addition, drought-like conditions limiting water usage can impact Generation s ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, may have an adverse effect by causing Generation to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

Certain long-lived assets and other assets recorded on the Registrants statements of financial position may become impaired, which would result in write-offs of the impaired amounts. (Exelon, Generation, ComEd, PECO and BGE)

Long-lived assets represent the single largest asset class on the Registrants statement of financial position. Specifically, long-lived assets account for 59%, 49%, 61%, 66% and 75% of total assets for Exelon, Generation, ComEd, PECO and BGE, respectively, as of December 31, 2013. In addition, the Registrants have significant balances related to unamortized energy contracts. See Notes 4 and 10 of the Combined Notes to Consolidated Financial Statements for additional information on Exelon s unamortized energy contracts. The Registrants evaluate the recoverability of the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment exist. Factors such as the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered when evaluating long-lived assets for potential impairment. An impairment would require the Registrants to reduce the carrying value of the long-lived asset through a non-cash charge to expense by the amount of the impairment, and such an impairment could have a material adverse impact on the Registrants results of operations.

Exelon and Generation have investments in certain generating plant projects, including the CENG nuclear joint venture with a carrying value of $1.9 billion as of December 31, 2013. These investments were acquired in the March 2012 Constellation transaction, and were recorded as equity method investments on the balance sheet at fair value on the merger date as part of purchase accounting. Exelon and Generation continuously monitor for issues that potentially could impact future profitability of these equity method investments and which could result in the recognition of an impairment loss if such issues indicate an other than temporary decline in value. Such impairment could have a material adverse impact on Exelon s and Generation s results of operations.

Exelon holds investments in coal-fired plants in Georgia and Texas subject to long-term leases. The investments are accounted for as direct financing lease investments. The investments represent the estimated residual values of the leased assets at the end of the respective lease terms. On an annual basis, Exelon reviews the estimated residual values of its direct financing lease investments and records a non-cash impairment charge to expense if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Such an impairment could have a material adverse impact on Exelon s results of operations.

Exelon and ComEd had approximately $2.6 billion of goodwill recorded at December 31, 2013 in connection with the merger between PECO and Unicom Corporation, the former parent company of ComEd. Under GAAP, goodwill remains at its recorded amount unless it is determined to be impaired, which is generally based upon an annual analysis that compares the implied fair value of the goodwill to its carrying value. If an impairment occurs, the amount of the impaired goodwill will be written-off, reducing equity. The actual timing and amounts of any goodwill impairments will depend on many sensitive, interrelated and uncertain variables. A successful IRS challenge to Exelon s and ComEd s like-kind exchange income tax position, adverse regulatory actions such as early termination of EIMA, or changes in significant assumptions used in estimating ComEd s fair value (e.g., discount and growth rates, utility sector market performance and transactions, operating and capital expenditure requirements and the fair value of debt) could result in an impairment. Such an impairment would result in a non-cash charge to expense, which could have a material adverse impact on Exelon s and ComEd s results of operations.

See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Critical Accounting Policies and Estimates and Notes 7, 8 and 10 of the Combined Notes to the Consolidated Financial Statements for additional discussion on long-lived asset and goodwill impairments.

The Registrants businesses are capital intensive, and their assets may require significant expenditures to maintain and are subject to operational failure, which could result in potential liability. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants businesses are capital intensive and require significant investments by Generation in energy generation and by ComEd, PECO and BGE in transmission and distribution infrastructure projects. These operational systems and infrastructure have been in service for many years. Older equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond the Registrants control, and may require significant expenditures to operate efficiently. The Registrants results of operations, financial condition, or cash flows could be adversely affected if they were unable to effectively manage their capital projects or raise the necessary capital. Furthermore, operational failure could result in potential liability if such failure results in damage to property or injury to individuals. See ITEM 1. BUSINESS for further information regarding the Registrants potential future capital expenditures.

Exelon and its subsidiaries have guaranteed the performance of third parties, which may result in substantial costs in the event of non-performance by third parties. In addition, the Registrants have rights under agreements which obligate third parties to indemnify the Registrants for various obligations, and the Registrants may incur substantial costs in the event that the applicable Registrant is unable to enforce those agreements or the applicable third-party is otherwise unable to perform. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have issued guarantees of the performance of third parties, which obligate one or more of the Registrants or their subsidiaries to perform in the event that the third parties do not perform. In the event of non-performance by those third parties, the Registrants could incur substantial cost to fulfill their obligations under these guarantees. Such performance guarantees could have a material impact on the operating results, financial condition, or cash flows of the Registrants.

The Registrants have entered into various agreements with counterparties that require those counterparties to reimburse a Registrant and hold it harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, the affected Registrant could be held responsible for the obligations, which could impact that Registrant s results of operations, cash flows and financial position. In connection with Exelon s 2001 corporate restructuring, Generation assumed certain of ComEd s and PECO s rights and obligations with respect to their former generation businesses. Further, ComEd and PECO may have entered into agreements with third parties under which the third-party agreed to indemnify ComEd or PECO for certain obligations related to their respective former generation businesses that have been assumed by Generation as part of the restructuring. If the third-party or Generation experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, ComEd or PECO could be liable for any existing or future claims, which could impact ComEd s or PECO s results of operations, cash flows and financial position.

Generation s business may be negatively affected by competitive electric generation suppliers. (Exelon and Generation)

Because retail customers where Generation serves load can switch from their respective energy delivery company to a competitive electric generation supplier for their energy needs, planning to meet Generation s obligation to provide the supply needed to serve Generation s share of an electric distribution company s default service obligation is more difficult than planning for retail load before the advent of retail competition. Before retail competition, the primary variables affecting projections of load were weather and the economy. With retail competition, another major factor is retail customers switching to or from competitive electric generation suppliers. If fewer of such customers switch from its retail load serving counterparties than Generation anticipates, the load that Generation must serve will be greater than anticipated, which could, if market prices have increased, increase Generation s costs (due to its need to go to market to cover its incremental supply obligation) more than the increase in Generation s revenues. If more customers from its retail load serving counterparties switch than Generation anticipates, the load that Generation must serve will be lower than anticipated, which could, if market prices have decreased, cause Generation to lose opportunities in the market.

Regulatory and Legislative Risks

The Registrants generation and energy delivery businesses are highly regulated and could be subject to adverse regulatory and legislative actions. Fundamental changes in regulation or legislation or violation of tariffs or market rules and anti-manipulation laws, could disrupt the Registrants business plans and adversely affect their operations and financial results. (Exelon, Generation, ComEd, PECO and BGE)

Substantially all aspects of the businesses of the Registrants are subject to comprehensive Federal or state regulation and legislation. Further, Exelon s and Generation s operating results and

cash flows are heavily dependent upon the ability of Generation to sell power at market-based rates, as opposed to cost-based or other similarly regulated rates, and Exelon s, ComEd s, PECO s and BGE s operating results and cash flows are heavily dependent on the ability of ComEd, PECO and BGE to recover their costs for the retail purchase and distribution of power to their customers. Similarly, there is risk that financial market regulations could increase the Registrants compliance costs and limit their ability to engage in certain transactions. In the planning and management of operations, the Registrants must address the effects of regulation on their businesses and changes in the regulatory framework, including initiatives by Federal and state legislatures, RTOs, exchanges, ratemaking agencies and taxing authorities. Additionally, the Registrants need to be cognizant of rules changes or Registrant actions that could result in potential violation of tariffs, market rules and anti-manipulation laws. Fundamental changes in regulations or other adverse legislative actions affecting the Registrants businesses would require changes in their business planning models and operations and could adversely affect their results of operations, cash flows and financial position.

Regulatory and legislative developments related to climate change and RPS may also significantly affect Exelon s and Generation s results of operations, cash flows and financial positions. Various legislative and regulatory proposals to address climate change through GHG emission reductions, if enacted, could result in increased costs to entities that generate electricity through carbon-emitting fossil fuels, which could increase the market price at which all generators in a region, including Generation, may sell their output, thereby increasing the revenue Generation could realize from its low-carbon nuclear assets. However, national regulation or legislation addressing climate change through an RPS could also increase the pace of development of wind energy facilities in the Midwest, which could put downward pressure on wholesale market prices for electricity from Generation s Midwest nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation s nuclear assets under a carbon constrained regulatory regime that might exist in the future. Current state level climate change and renewable regulation is already providing incentives for regional wind development. The Registrants cannot predict when or whether any of these various legislative and regulatory proposals may become law or what their effect will be on the Registrants.

Generation may be negatively affected by possible Federal or state legislative or regulatory actions that could affect the scope and functioning of the wholesale markets. (Exelon and Generation)

Federal and state legislative and regulatory bodies are facing pressures to address consumer concerns, or are themselves raising concerns, that energy prices in wholesale markets are too high or insufficient generation is being built because the competitive model is not working, and, therefore, are considering some form of re-regulation or some other means of reducing wholesale market prices or subsidizing new generation. Generation is dependent on robust and competitive wholesale energy markets to achieve its business objectives.

Approximately 60% of Generation s generating resources, which include directly owned assets and capacity obtained through long-term contracts, are located in the area encompassed by PJM. Generation s future results of operations will depend on 1) FERC s continued adherence to and support for, policies that favor the preservation of competitive wholesale power markets, such as PJM s, and (2) the absence of material changes to market structures that would limit or otherwise negatively affect market competitiveness. Generation could also be adversely affected by state laws, regulations or initiatives designed to reduce wholesale prices artificially below competitive levels or to subsidize new generation, such as the subsequently dismissed New Jersey Capacity Legislation and the MDPSC s RFP for new gas-fired generation in Maryland. See Note 3 of the Combined Notes to Consolidated Financial Statements for further details related to the New Jersey Capacity Legislation and the Maryland new electric generation requirements.

In addition, FERC s application of its Order 697 and its subsequent revisions could pose a risk that Generation will have difficulty satisfying FERC s tests for market-based rates. Since Order 697 became final in June 2007, Generation has obtained orders affirming Generation s authority to sell at market-based rates and none denying that authority. On December 31, 2013, Generation submitted its triennial application seeking reauthorization to sell at market-based rates in the Northeast region (including PJM, ISO-NY and ISONE). Generation s previous submission seeking reauthorization to sell at market-based rates was accepted by FERC on June 22, 2011 for the PJM region.

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 that unfolded during 2008. Dodd-Frank ushers in a brand new regulatory regime 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. In April 2012, the CFTC issued its rule defining swap dealers and major swap participants. Generation has determined that it will conduct its commercial hedging business as an end user in a manner that does not require registration as a swap dealer or major swap participant.

Notwithstanding the foregoing, Generation will still face additional regulatory obligations under Dodd-Frank, including some reporting requirements, clearing some additional transactions that it would otherwise enter into over-the-counter, and having to adhere to position limits. More fundamentally, however, the total burden that the rules could impose on all market participants could cause liquidity in the bilateral OTC swaps market to decrease substantially. Dodd-Frank may require up to $1 billion of additional collateral requirements at Generation, to be met with cash rather than letters of credit in a price stressed environment. 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.

Generation s affiliation with ComEd, PECO and BGE, together with the presence of a substantial percentage of Generation s physical asset base within the ComEd, PECO and BGE service territories, could increase Generation s cost of doing business to the extent future complaints or challenges regarding ComEd, PECO and/or BGE retail rates result in settlements or legislative or regulatory requirements funded in part by Generation. (Exelon and Generation)

Generation has significant generating resources within the service areas of ComEd, PECO and BGE and makes significant sales to each of them. Those facts tend to cause Generation to be directly affected by developments in those markets. Government officials, legislators and advocacy groups are aware of Generation s affiliation with ComEd, PECO and BGE and its sales to each of them. In periods of rising utility rates, particularly when driven by increased costs of energy production and supply, those officials and advocacy groups may question or challenge costs incurred by ComEd, PECO or BGE, including transactions between Generation, on the one hand, and ComEd, PECO or BGE, on the other hand, regardless of any previous regulatory processes or approvals underlying those transactions. The prospect of such challenges may increase the time, complexity and cost of the associated regulatory proceedings, and the occurrence of such challenges may subject Generation to a level of scrutiny not faced by other unaffiliated competitors in those markets. In addition, government officials and legislators may seek ways to force Generation to contribute to efforts to mitigate potential or actual rate increases, through measures such as generation-based taxes and contributions to rate-relief packages.

The Registrants may incur substantial costs to fulfill their obligations related to environmental and other matters. (Exelon, Generation, ComEd, PECO and BGE)

The businesses which the Registrants operate are subject to extensive environmental regulation and legislation by local, state and Federal authorities. These laws and regulations affect the manner in which the Registrants conduct their operations and make capital expenditures including how they handle air and water emissions and solid waste disposal. Violations of these emission and disposal requirements can subject the Registrants to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean-up costs, civil penalties and exposure to third parties claims for alleged health or property damages or operating restrictions to achieve compliance. In addition, the Registrants are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by the Registrants and of property contaminated by hazardous substances they generate. The Registrants have incurred and expect to incur significant costs related to environmental compliance, site remediation and clean-up. Remediation activities associated with MGP operations conducted by predecessor companies are one component of such costs. Also, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

If application of Section 316(b) of the Clean Water Act, which establishes a national requirement for reducing the adverse impacts to aquatic organisms at existing generating stations, requires the retrofitting of cooling water intake structures at Salem or other Exelon power plants, this development could result in material costs of compliance. Pursuant to discussions with the NJDEP regarding the application of Section 316(b) to Oyster Creek, Generation agreed to permanently cease generation operations at Oyster Creek by December 31, 2019, ten years before the expiration of its operating license in 2029.

Additionally, Generation is subject to exposure for asbestos-related personal injury liability alleged at certain current and formerly owned generation facilities. Future legislative action could require Generation to make a material contribution to a fund to settle lawsuits for alleged asbestos-related disease and exposure.

In some cases, a third-party who has acquired assets from a Registrant has assumed the liability the Registrant may otherwise have for environmental matters related to the transferred property. If the transferee is unable, or fails, to discharge the assumed liability, a regulatory authority or injured person could attempt to hold the Registrant responsible, and the Registrant s remedies against the transferee may be limited by the financial resources of the transferee. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

Changes in ComEd s, PECO s and BGE s respective terms and conditions of service, including their respective rates, are subject to regulatory approval proceedings and/or negotiated settlements that are at times contentious, lengthy and subject to appeal, which lead to uncertainty as to the ultimate result and which may introduce time delays in effectuating rate changes. (Exelon, ComEd, PECO and BGE)

ComEd, PECO and BGE are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for ComEd, PECO or BGE to recover its costs by the time the rates become effective. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates can be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, MGP remediation, smart grid infrastructure, and energy efficiency and demand response programs.

In certain instances, ComEd, PECO and BGE may agree to negotiated settlements related to various rate matters, customer initiatives or franchise agreements. These settlements are subject to regulatory approval.

ComEd, PECO and BGE cannot predict the ultimate outcomes of any settlements or the actions by Illinois, Pennsylvania, Maryland or Federal regulators in establishing rates, including the extent, if any, to which certain costs such as significant capital projects will be recovered or what rates of return will be allowed. Nevertheless, the expectation is that ComEd, PECO and BGE will continue to be obligated to deliver electricity to customers in their respective service territories and will also retain significant POLR and default service obligations to provide electricity and natural gas to certain groups of customers in their respective service areas who do not choose an alternative supplier. The ultimate outcome and timing of regulatory rate proceedings have a significant effect on the ability of ComEd, PECO and BGE, as applicable, to recover their costs and could have a material adverse effect on ComEd s, PECO s and BGE s results of operations, cash flows and financial position. See Note 3 of the Combined Notes to the Consolidated Financial Statements for information regarding rate proceedings.

Federal or additional state RPS and/or energy conservation legislation, along with energy conservation by customers, could negatively affect the results of operations and cash flows of Generation, ComEd, PECO and BGE. (Exelon, Generation, ComEd, PECO and BGE)

Changes to current state legislation or the development of Federal legislation that requires the use of renewable and alternate fuel sources, such as wind, solar, biomass and geothermal, could significantly impact Generation, ComEd, PECO and BGE, especially if timely cost recovery is not allowed. The impact could include increased costs for RECs and purchased power and increased rates for customers.

Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart meters and smart grid, have increased capital expenditures and could significantly impact ComEd, PECO and BGE, if timely cost recovery is not allowed. Furthermore, regulated energy consumption reduction targets and declines in customer energy consumption resulting from the implementation of new energy conservation technologies could lead to a decline in the revenues of Exelon, ComEd, and PECO. For additional information, see ITEM 1. BUSINESS Environmental Regulation-Renewable and Alternative Energy Portfolio Standards.

The impact of not meeting the criteria of the FASB guidance for accounting for the effects of certain types of regulation could be material to Exelon, ComEd, PECO and BGE. (Exelon, ComEd, PECO and BGE)

As of December 31, 2013, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE meet the criteria of the authoritative guidance for accounting for the effects of certain types of regulation. If it is concluded in a future period that a separable portion of their businesses no longer meets the criteria, Exelon, ComEd, PECO and BGE would be required to eliminate the financial statement effects of regulation for that part of their business. That action would include the elimination of any or all regulatory assets and liabilities that had been recorded in their Consolidated Balance Sheets and the recognition of a one-time extraordinary item in their Consolidated Statements of Operations. The impact of not meeting the criteria of the authoritative guidance could be material to the financial statements of Exelon, ComEd, PECO and BGE. At December 31, 2013, the extraordinary gain (loss) could have been as much as $(2.4) billion, $730 million and $ 453 million (before taxes) as a result of the elimination of ComEd s, PECO s and BGE s regulatory assets and liabilities, respectively. Further, Exelon would record a charge against OCI (before taxes) of up to $2.4 billion and $568 million for ComEd and BGE, respectively, related to Exelon s regulatory assets associated with its defined benefit postretirement plans. Exelon also has a regulatory liability of $45 million (before taxes) associated with PECO s defined benefit postretirement plans that would result in an increase in OCI if reversed. The impacts and resolution of the above items could lead to an additional impairment of ComEd s goodwill, which could be significant and at least partially offset the extraordinary gain at ComEd discussed above. A significant decrease in equity as a result of any changes could limit the ability of ComEd, PECO and BGE to pay dividends under Federal and state law and no longer meeting the regulatory accounting criteria could cause significant volatility in future results of operations. See Notes 1, 3 and 10 of the Combined Notes to Consolidated Financial Statements for additional information regarding accounting for the effects of regulation, regulatory matters and ComEd s goodwill, respectively.

Exelon and Generation may incur material costs of compliance if Federal and/or state regulation or legislation is adopted to address climate change. (Exelon and Generation)

Various stakeholders, including legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors, including utilities, are considering ways to address the effect of GHG emissions on climate change. In 2009, select Northeast and Mid-Atlantic states implemented a model rule, developed via the RGGI, to regulate CO_2 emissions from fossil-fired generation. RGGI states are working on updated programs to further limit emissions and the EPA has introduced regulation to address greenhouse gases from new fossil plants that could potentially impact existing plants. If carbon reduction regulation or legislation becomes effective, Exelon and Generation may incur costs either to limit further the GHG emissions from their operations or to procure emission allowance credits. The nature and extent of environmental regulation may also impact the ability of Exelon and its subsidiaries to meet the GHG emission reduction targets of Exelon 2020. For example, more stringent permitting requirements may preclude the construction of lower-carbon nuclear and gas-fired power plants. Similarly, a Federal RPS could increase the cost of compliance by mandating the purchase or construction of more expensive supply alternatives. For more information regarding climate change, see ITEM 1. BUSINESS Global Climate Change and Note 22 of the Combined Notes to Consolidated Financial Statements.

The Registrants could be subject to higher costs and/or penalties related to mandatory reliability standards, including the likely exposure of ComEd, PECO, and BGE to the results of PJM s RTEP and NERC compliance requirements. (Exelon, Generation, ComEd, PECO and BGE)

As a result of the Energy Policy Act of 2005, users, owners and operators of the bulk power transmission system, including Generation, ComEd, PECO and BGE, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. As operators of natural gas distribution systems, PECO and BGE are also subject to mandatory reliability standards of the U.S. Department of Transportation. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards may subject the Registrants to higher operating costs and/or increased capital expenditures. In addition, the ICC, PAPUC and MDPSC impose certain distribution reliability standards on ComEd, PECO and BGE, respectively. If the Registrants were found not to be in compliance with the mandatory reliability standards, they could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties.

ComEd, PECO and BGE as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments may require ComEd, PECO and BGE to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. Uncertainties exist as to the construction of new transmission facilities, their cost and how those costs will be allocated to transmission system participants and customers. In accordance with a FERC order and related settlement, PJM s RTEP requires the costs of new transmission facilities to be allocated across the entire PJM footprint for new facilities greater than or equal to 500 kV, and requires costs of new facilities less than 500 kV to be allocated to the beneficiaries of the new facilities. Following a remand from the U.S. Court of Appeals for the Seventh Circuit, FERC reaffirmed its decision related to allocation of new facilities 500 kV and above. That decision is being appealed to the U.S. Court of Appeals for the Seventh Circuit. This FERC order only applies to facilities included in the PJM RTEP prior to February 1, 2013. For facilities subsequently approved, the costs of new facilities that are double circuit 345 kV or greater than or equal to 500 kV will be allocated 50% across the entire PJM footprint and 50% allocated to identified beneficiaries. Costs for all other facilities will be allocated to all identified beneficiaries. This later decision is subject to rehearing by FERC and possible appeal.

See Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants cannot predict the outcome of the legal proceedings relating to their business activities. An adverse determination could have a material adverse effect on their results of operations, financial positions and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are involved in legal proceedings, claims and litigation arising out of their business operations, the most significant of which are summarized in Note 22 of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures that could have a material adverse effect on the Registrants results of operations.

Generation may be negatively affected by possible Nuclear Regulatory Commission actions that could affect the operations and profitability of its nuclear generating fleet. (Exelon and Generation)

Regulatory risk. A change in the Atomic Energy Act or the applicable regulations or licenses may require a substantial increase in capital expenditures or may result in increased operating or decommissioning costs and significantly affect Generation s results of operations or financial position. Events at nuclear plants owned by others, as well as those owned by Generation, may cause the NRC to initiate such actions.

As an example, prior to the Fukushima Daiichi accident on March 11, 2011, the NRC had been evaluating seismic risk. After the Fukushima Daiichi accident, the NRC s focus on seismic risk intensified. As part of the NRC Near-Term Task Force (Task Force) review and evaluation of the Fukushima Daiichi accident, the Task Force recommended that plant operators conduct seismic reevaluations. 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. These reevaluations could result in the required implementation of additional mitigation strategies or modifications. Additionally, the Task Force provided recommendations for future regulatory action by the NRC to be taken in the near and longer term. In response, the NRC issued three immediately effective orders (Tier 1) to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. The NRC is currently evaluating the remaining Task Force recommendations and has not taken action with respect to the Tier 2 and Tier 3 recommendations. Actions to comply with the Task Force recommendations will result in increased costs and could significantly impact Generation s results of operations or financial position. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Exelon Corporation, Executive Overview for a more detailed discussion of the Task Force Recommendations.

Spent nuclear fuel storage. The approval of a national repository for the storage of SNF, such as the one previously considered at Yucca Mountain, Nevada, and the timing of such facility opening, will significantly affect the costs associated with storage of SNF, and the ultimate amounts received from the DOE to reimburse Generation for these costs. The NRC s temporary storage rule (also referred to as the waste confidence decision) recognizes that licensees can safely store spent nuclear fuel at nuclear power plants for up to 60 years beyond the original and renewed licensed operating life of the plants. In June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC s temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. In September 2012, the NRC directed NRC Staff to complete a generic environmental impact statement and to revise the temporary storage rule which is now not expected until October 3, 2014.

Any regulatory action relating to the timing and availability of a repository for SNF may adversely affect Generation s ability to decommission fully its nuclear units. In accordance with the NWPA and Generation s contract with the DOE, Generation pays the DOE ongoing fees 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. On November 19, 2013, the United States Court of Appeals for the District of Columbia Circuit ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. Until such time as a new fee structure is in effect, Generation must continue to pay the current SNF disposal fees. Furthermore, under its contract with the DOE, Generation would be required to pay the DOE a one-time SNF storage fee including interest of approximately $1 billion as of December 31, 2013, prior to the first delivery of SNF. Generation currently estimates 2025 to be the earliest date when the DOE will begin accepting SNF, which could be delayed by further regulatory action. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information on the spent nuclear fuel obligation.

License renewals. Generation cannot assure that economics will support the continued operation of the facilities for all or any portion of any renewed license period. If the NRC does not renew the operating licenses for Generation s nuclear stations or a station cannot be operated through the end of its operating license, Generation s results of operations could be adversely affected by increased depreciation rates, impairment charges and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. In addition, Generation may lose revenue and incur increased fuel and purchased power expense to meet supply commitments.

As discussed above, in June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC s temporary storage rule. Generation does not expect the NRC to issue license renewals until the end of 2014, at the earliest.

Operational Risks

The Registrants employees, contractors, customers and the general public may be exposed to a risk of injury due to the nature of the energy industry. (Exelon, Generation, ComEd, PECO and BGE)

Employees and contractors throughout the organization work in, and customers and the general public may be exposed to, potentially dangerous environments near their operations. As a result, employees, contractors, customers and the general public are at risk for serious injury, including loss of life. Significant risks include nuclear accidents, dam failure, gas explosions, pole strikes and electric contact cases.

Natural disasters, war, acts and threats of terrorism, pandemic and other significant events may adversely affect Exelon s results of operations, its ability to raise capital and its future growth. (Exelon, Generation, ComEd, PECO and BGE)

Generation s fleet of nuclear and fossil-fueled power plants and ComEd s, PECO s and BGE s distribution and transmission infrastructures could be affected by natural disasters, such as seismic activity, more frequent and more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Registrants service areas can also directly affect their capital assets, causing disruption in service to customers

due to downed wires and poles or damage to other operating equipment. Examples of such events include the June 2012 Derecho storm, which interrupted electric service delivery to customers in BGE s service territory, and the October 2012 category 1 hurricane, Hurricane Sandy, which interrupted electric service delivery to customers in PECO s and BGE s service territories and resulted in significant costs to PECO and BGE for restoration efforts.

Other events include the 9.0 magnitude earthquake and ensuing tsunami experienced by Japan on March 11, 2011, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co., and the 5.8 magnitude earthquake and flooding associated with Hurricane Irene and Tropical Storm Lee that the Mid-Atlantic region of the United States experienced in 2011. These events increase the risk to Generation that the NRC or other regulatory or legislative bodies may change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological aspects. In addition, natural disasters could affect the availability of a secure and economical supply of water in some locations, which is essential for Generation s continued operation, particularly the cooling of generating units. Additionally, natural disasters and other events that have an adverse effect on the economy in general may adversely affect the Registrants operations and their ability to raise capital.

Exelon does not know the impact that potential terrorist attacks could have on the industry in general and on Exelon in particular. As owner-operators of infrastructure facilities, such as nuclear, fossil and hydroelectric generation facilities and electric and gas transmission and distribution facilities, the Registrants face a risk that their operations would be direct targets of, or indirect casualties of, an act of terror. Any retaliatory military strikes or sustained military campaign may affect their operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. Furthermore, these catastrophic events could compromise the physical or cyber security of Exelon s facilities, which could adversely affect Exelon s ability to manage its business effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession or other factors also may result in a decline in energy consumption, which may adversely affect the Registrants results of operations and its ability to raise capital. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

The Registrants would be significantly affected by the outbreak of a pandemic. Exelon has plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate its generating and transmission and distribution assets could be affected, resulting in decreased service levels and increased costs.

In addition, Exelon maintains a level of insurance coverage consistent with industry practices against property and casualty losses subject to unforeseen occurrences or catastrophic events that may damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses.

Generation s financial performance may be negatively affected by matters arising from its ownership and operation of nuclear facilities. (Exelon and Generation)

Nuclear capacity factors. Capacity factors for generating units, particularly capacity factors for nuclear generating units, significantly affect Generation s results of operations. Nuclear plant operations involve substantial fixed operating costs but produce electricity at low variable costs due to nuclear fuel costs typically being lower than fossil fuel costs. Consequently, to be successful, Generation must consistently operate its nuclear facilities at high capacity factors. Lower capacity factors increase Generation s operating costs by requiring Generation to produce additional energy from primarily its fossil facilities or purchase additional energy in the spot or forward markets in order to satisfy Generation s obligations to committed third-party sales, including ComEd, PECO and BGE. These sources generally have higher costs than Generation incurs to produce energy from its nuclear stations.

Nuclear refueling outages. In general, refueling outages are planned to occur once every 18 to 24 months. The total number of refueling outages, along with their duration, can have a significant impact on Generation s results of operations. When refueling outages at wholly and co-owned plants last longer than anticipated or Generation experiences unplanned outages, capacity factors decrease and Generation faces lower margins due to higher energy replacement costs and/or lower energy sales.

Nuclear fuel quality. The quality of nuclear fuel utilized by Generation can affect the efficiency and costs of Generation s operations. Certain of Generation s nuclear units have previously had a limited number of fuel performance issues. Remediation actions could result in increased costs due to accelerated fuel amortization, increased outage costs and/or increased costs due to decreased generation capabilities.

Operational risk. Operations at any of Generation s nuclear generation plants could degrade to the point where Generation has to shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. Generation may choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, Generation may lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, Generation may not achieve the anticipated results under its series of planned power uprates across its nuclear fleet. For plants operated but not wholly owned by Generation, Generation may also incur liability to the co-owners. For plants not operated and not wholly owned by Generation, from which Generation receives a portion of the plants output, Generation s results of operations are dependent on the operational performance of the operators and could be adversely affected by a significant event at those plants. Additionally, poor operating performance at nuclear plants not owned by Generation could result in increased regulation and reduced public support for nuclear-fueled energy, which could significantly affect Generation s results of operations or financial position. In addition, closure of generating plants owned by others, or extended interruptions of generating plants or failure of transmission lines, could affect transmission systems that could adversely affect the sale and delivery of electricity in markets served by Generation.

Nuclear major incident risk. Although the safety record of nuclear reactors generally has been very good, accidents and other unforeseen problems have occurred both in the United States and abroad. The consequences of a major incident can be severe and include loss of life and property damage. Any resulting liability from a nuclear plant major incident within the United States, owned or operated by Generation or owned by others, may exceed Generation s resources, including insurance coverage. Uninsured losses and other expenses, to the extent not recovered from insurers or the nuclear industry, could be borne by Generation and could have a material adverse effect on Generation s results of operations or financial position. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, owned by others or Generation, may result in increased regulation and reduced public support for nuclear-fueled energy and significantly affect Generation s results of operations or financial position.

Nuclear insurance. As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance. The required amount of nuclear liability insurance is $375 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims exceeding the $13.6 billion limit for a single incident.

Generation is a member of an industry mutual insurance company, NEIL, which provides property and business interruption insurance for Generation s nuclear operations. In previous years, NEIL has made distributions to its members but Generation cannot predict the level of future distributions or if they will occur at all. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional discussion of nuclear insurance.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. Generation is required to provide to the NRC a biennial report by unit (annually for Generation s two units that have been retired) addressing Generation s ability to meet the NRC-estimated funding levels including scheduled contributions to and earnings on the decommissioning trust funds. The NRC funding levels are based upon the assumption that decommissioning will commence after the end of the current licensed life of each unit.

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results may differ significantly from current estimates. The performance of capital markets also can significantly affect the value of the trust funds. Currently, Generation is making contributions to certain trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to Generation. While Generation has recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), it has no recourse to collect additional amounts from ComEd customers or from the previous owners of Clinton, TMI Unit No. 1 and Oyster Creek generating stations, if there is a shortfall of funds necessary for decommissioning. If circumstances changed such that Generation would be unable to continue to make contributions to the trust funds of the former PECO units based on amounts collected from PECO customers, or if Generation no longer had recourse to collect additional amounts from PECO customers if there was a shortfall of funds for decommissioning, the adequacy of the trust funds related to the former PECO units may be negatively affected and Exelon s and Generation s results of operations and financial position could be significantly affected. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Ultimately, if the investments held by Generation s NDTs are not sufficient to fund the decommissioning of Generation s nuclear plants, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met. As a result, Generation s cash flows and financial position may be significantly adversely affected. See Note 15 of the Combined Notes to Consolidated Financial Statements for additional information.

Generation s financial performance may be negatively affected by risks arising from its ownership and operation of hydroelectric facilities. (Exelon and Generation)

FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways, Federal lands or connected to the interstate electric grid. The license for the Conowingo Hydroelectric Project expires August 31, 2014, and the license for the Muddy Run Pumped Storage Project expires on September 1, 2014. Generation cannot predict whether it will receive all the regulatory approvals for the renewed licenses of its hydroelectric facilities. If FERC does not issue new operating licenses for Generation s hydroelectric facilities or a station cannot be operated through the end of its operating license, Generation s results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. Generation may also lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, conditions may be imposed as part of the license renewal process that may adversely affect operations, may require a substantial increase in capital expenditures or may result in increased operating costs and significantly affect Generation s results of operations or financial position. Similar effects may result from a change in the Federal Power Act or the applicable regulations due to events at hydroelectric facilities owned by others, as well as those owned by Generation.

ComEd s, PECO s and BGE s operating costs, and customers and regulators opinions of ComEd, PECO and BGE, respectively, are affected by their ability to maintain the availability and reliability of their delivery and operational systems. (Exelon, ComEd, PECO and BGE)

Failures of the equipment or facilities, including information systems, used in ComEd s, PECO s and BGE s delivery systems can interrupt the electric transmission and electric and natural gas delivery, which could negatively impact related revenues, and increase maintenance and capital expenditures. Equipment or facilities failures can be due to a number of factors, including weather or information systems failure. Specifically, if the implementation of advanced metering infrastructure, smart grid or other technologies in ComEd s, PECO s or BGE s service territory fail to perform as intended or are not successfully integrated with billing and other information systems, ComEd s, PECO s and BGE s financial condition, results of operations, and cash flows could be adversely affected. Furthermore, if any of the financial, accounting, or other data processing systems fail or have other significant shortcomings, ComEd s, PECO s or BGE s financial results could be adversely affected. If an employee causes the operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating the operational systems, ComEd s, PECO s or BGE s financial results could also be adversely affected. In addition, dependence upon automated systems may further increase the risk that operational system flaws or employee tampering or manipulation of those systems will result in losses that are difficult to detect.

The aforementioned failures or those of other utilities, including prolonged or repeated failures, can affect customer satisfaction and the level of regulatory oversight and ComEd s, PECO s and BGE s maintenance and capital expenditures. Regulated utilities, which are required to provide service to all customers within their service territory, have generally been afforded liability protections against claims by customers relating to failure of service. Under Illinois law, however, ComEd can be required to pay damages to its customers in some circumstances involving extended outages affecting large numbers of its customers, and those damages could be material to ComEd s results of operations and cash flows. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding proceedings related to storm-related outages in ComEd s service territory.

ComEd s, PECO s and BGE s respective ability to deliver electricity, their operating costs and their capital expenditures may be negatively affected by transmission congestion. (Exelon, ComEd, PECO and BGE)

Demand for electricity within ComEd s, PECO s and BGE s service areas could stress available transmission capacity requiring alternative routing or curtailment of electricity usage with consequent effects on operating costs, revenues and results of operations. Also, insufficient availability of electric supply to meet customer demand could jeopardize ComEd s, PECO s and BGE s ability to comply with reliability standards and strain customer and regulatory agency relationships. As with all utilities, potential concerns over transmission capacity or generation facility retirements could result in PJM or FERC requiring ComEd, PECO and BGE to upgrade or expand their respective transmission systems through additional capital expenditures.

Failure to attract and retain an appropriately qualified workforce may negatively impact the Registrants results of operations. (Exelon, Generation, ComEd, PECO and BGE)

Certain events, such as an employee strike, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, may lead to operating challenges and increased costs for the Registrants. The challenges include lack of resources, loss of knowledge and a lengthy time

period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may arise. The Registrants are particularly affected due to the specialized knowledge required of the technical and support employees for their generation, transmission and distribution operations. If the Registrants are unable to successfully attract and retain an appropriately qualified workforce, their results of operations could be negatively affected.

The Registrants are subject to physical and information security risks. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants face physical and information security risks as the owner-operators of generation, transmission and distribution facilities. A security breach of the physical assets or information systems of the Registrants, their competitors, RTOs and ISOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or subject the Registrants to financial harm associated with theft or inappropriate release of certain types of information, including sensitive customer data. If a significant breach occurred, the reputation of Exelon and its customer supply activities may be adversely affected, customer confidence in the Registrants or others in the industry may be diminished, or Exelon and its subsidiaries may be subject to legal claims, any of which may contribute to the loss of customers and have a negative impact on the business and/or results of operations. ComEd s, PECO s and BGE s deployment of smart meters throughout their service territories may increase the risk of damage from an intentional disruption of the system by third parties. As a requirement of their SGIG grant, the DOE approved PECO s and BGE s cyber security plan related to its smart meter deployment and will review the plan annually through the expiration of the grant. As with most companies in today s environment, Exelon experiences attempts by hackers to infiltrate its corporate network. To date there have been no infiltrations that have resulted in loss of data or any significant effects on business operations. Exelon utilizes a dedicated team of cyber security professionals to ensure the protection of its information and ability to conduct business operations. Despite the measures taken by the Registrants to prevent a security breach, the Registrants cannot accurately assess the probability that a security breach may occur and are unable to quantify the potential impact of such an event. In addition, new or updated security regulations could require changes in current measures taken by the Registrants or their business operations and could adversely affect their results of operations, cash flows and financial position.

The Registrants may make investments in new business initiatives, including initiatives mandated by regulators, and markets that may not be successful, and acquisitions may not achieve the intended financial results. (Exelon, Generation, ComEd, PECO and BGE)

Generation continuously looks to invest in new business initiatives and actively participate in new markets. These include, but are not limited to, unconventional oil and gas exploration and production, residential power and gas sales, solar and wind generation, and managed load response. Such initiatives may involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered in the diligence performed prior to launching an initiative or entering a market. As these markets mature, there may be new market entrants or expansion by established competitors that increase competition for customers and resources. Additionally, it is possible that FERC, state public utility commissions or others may impose certain other restrictions on such transactions. All of these factors could result in higher costs or lower revenues than expected, resulting in lower than planned returns on investment. ComEd, PECO and BGE face risks associated with the Smart Grid mandated regulatory initiative. These risks include, but are not limited to, cost recovery, regulatory concerns, cyber security and obsolescence of technology. Due to these risks, no assurance can be given that such initiatives will be successful and will not have a material adverse effect on ComEd s, PECO s or BGE s financial results.

Risks Related to the Merger

Exelon may encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals for the Constellation merger.

As a result of the process to obtain regulatory approvals required for the Constellation merger, Exelon is committed to various programs, contributions, investments and market mitigation measures in several settlement agreements and regulatory approval orders. It is possible that Exelon may encounter delays, unexpected difficulties or costs in meeting these commitments in compliance with the terms of the relevant agreements and orders. Failure to fulfill the commitments in accordance with their terms could result in increased costs or result in penalties or fines that could adversely affect Exelon s financial position and operating results.

Risks Related to the Pending Master Agreement with CENG

The integration of CENG s nuclear fleet may not achieve its anticipated results, and Exelon and Generation may not be able to fully integrate the operations of CENG in the manner expected.

Exelon, Generation and subsidiaries of Generation entered into a Master Agreement with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG that will result in Generation operating the CENG nuclear generation fleet. The Master Agreement was entered into with the expectation that it will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the agreement is subject to a number of uncertainties, including whether CENG can be integrated into Generation in an efficient, effective and timely manner. Integration will take place, and additional agreements will be signed, upon receipt of regulatory approvals for the transfer of CENG s nuclear operating licences to Generation.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of Generation s business, processes and systems or inconsistencies in standards, controls, procedures, practices, policies, valuation models, and compensation arrangements. In addition, Generation may have difficulty addressing possible differences in corporate cultures and management philosophies. Any of these circumstances could adversely affect Generation s ability to achieve the anticipated benefits of the agreement as and when expected. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect Generation s future business, financial condition, operating results and prospects.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Exelon, Generation, ComEd, PECO and BGE

None.

ITEM 2. PROPERTIES

Generation

The following table describes Generation s interests in net electric generating capacity by station at December 31, 2013:

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
Limerick	Mid-Atlantic	Sanatoga, PA	2		Uranium	Base-load	2,316
Peach Bottom	Mid-Atlantic	Delta, PA	2	50	Uranium	Base-load	1,167[f]
Salem	Mid-Atlantic	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	1,006[f]
Calvert Cliffs	Mid-Atlantic	Lusby, MD	2	50.01	Uranium	Base-load	878[f][h]
Three Mile Island	Mid-Atlantic	Middletown, PA	1		Uranium	Base-load	837
Keystone	Mid-Atlantic	Shelocta, PA	2	41.98	Coal	Base-load	714[f]
Oyster Creek	Mid-Atlantic	Forked River, NJ	1		Uranium	Base-load	625[e]
Conowingo	Mid-Atlantic	Darlington, MD	11		Hydroelectric	Base-load	572
Conemaugh	Mid-Atlantic	New Florence, PA	2	31.28	Coal	Base-load	532[f]
Criterion	Mid-Atlantic	Oakland, MD	28		Wind	Base-load	70
Colver	Mid-Atlantic	Colver Twp., PA	1	25	Waste Coal	Base-load	26[f]
Solar Horizons	Mid-Atlantic	Emmitsburg, MD	1		Solar	Base-load	16
Solar New Jersey 2	Mid-Atlantic	Various	2		Solar	Base-load	10
Solar New Jersey 1	Mid-Atlantic	Various	4		Solar	Base-load	10
Solar Maryland	Mid-Atlantic	Various	9		Solar	Base-load	9
Solar Federal	Mid-Atlantic	Trenton, NJ	1		Solar	Base-load	5
Solar Maryland 2	Mid-Atlantic	Pocomoke, MD	2		Solar	Base-load	4
Solar New York	Mid-Atlantic	Various	1		Solar	Base-load	3
Solar New Jersey 3	Mid-Atlantic	Middle Township, NJ	5		Solar	Base-load	2
Muddy Run	Mid-Atlantic	Drumore, PA	8		Hydroelectric	Intermediate	1,070
Eddystone 3, 4	Mid-Atlantic	Eddystone, PA	2		Oil/Gas	Intermediate	760
Safe Harbor	Mid-Atlantic	Conestoga, PA	12	66.7	Hydroelectric	Intermediate	278[f]
Croydon	Mid-Atlantic	West Bristol, PA	8		Oil	Peaking	391
Perryman	Mid-Atlantic	Belcamp, MD	5		Oil/Gas	Peaking	353
Handsome Lake	Mid-Atlantic	Kennerdell, PA	5		Gas	Peaking	268
Riverside	Mid-Atlantic	Baltimore, MD	4		Oil/Gas	Peaking	228
Westport	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	115
Notch Cliff	Mid-Atlantic	Baltimore, MD	8		Gas	Peaking	118
Richmond	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	98
Gould Street	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	97
Philadelphia Road	Mid-Atlantic	Baltimore, MD	4		Oil	Peaking	61
Eddystone	Mid-Atlantic	Eddystone, PA	4		Oil	Peaking	60
Fairless Hills	Mid-Atlantic	Fairless Hills, PA	2		Landfill Gas	Peaking	60
Delaware	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	56
Southwark	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	52
Falls	Mid-Atlantic	Morrisville, PA	3		Oil	Peaking	51
Moser	Mid-Atlantic	Lower PottsgroveTwp., PA	3		Oil	Peaking	51
Chester	Mid-Atlantic	Chester, PA	3		Oil	Peaking	39
Schuylkill	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	30
Salem	Mid-Atlantic	Lower Alloways Creek Twp, NJ	1	42.59	Oil	Peaking	16[f]
Pennsbury	Mid-Atlantic	Morrisville, PA	2		Landfill Gas	Peaking	6
Keystone	Mid-Atlantic	Shelocta, PA	4	41.98	Oil	Peaking	4[f]
Conemaugh	Mid-Atlantic	New Florence, PA	4	31.28	Oil	Peaking	3[f]
Total Mid-Atlantic							13,067
Braidwood	Midwest	Braidwood, IL	2		Uranium	Base-load	2,353
LaSalle	Midwest	Seneca, IL	2		Uranium	Base-load	2,327
Byron	Midwest	Byron, IL	2		Uranium	Base-load	2,319
Dresden	Midwest	Morris, IL	2		Uranium	Base-load	1,843

Quad Cities	Midwest	Cordova, IL	2	75	Uranium	Base-load	1,403[(f)]
Clinton	Midwest	Clinton, IL	1		Uranium	Base-load	1,067
Michigan Wind 2	Midwest	Sanilac Co., MI	50		Wind	Base-load	90

Station (a)	Region	Location	No. of Units	Percent Owned (b)	Primary Fuel Type	Primary Dispatch Type (c)	Net Generation Capacity (MW) (d)
Beebe	Midwest	Gratiot Co., MI	34		Wind	Base-load	81
Michigan Wind 1	Midwest	Huron Co., MI	46		Wind	Base-load	69
Harvest 2	Midwest	Huron Co., MI	33		Wind	Base-load	59
Harvest	Midwest	Huron Co., MI	32		Wind	Base-load	53
Ewington	Midwest	Jackson Co., MN	10	99	Wind	Base-load	21(f)
Marshall	Midwest	Lyon Co., MN	9	99	Wind	Base-load	19(f)
City Solar	Midwest	Chicago, IL	1		Solar	Base-load	8
Norgaard	Midwest	Lincoln Co., MN	7	99	Wind	Base-load	9(f)
AgriWind	Midwest	Bureau Co., IL	4	99	Wind	Base-load	8(f)
Cisco	Midwest	Jackson Co., MN	4	99	Wind	Base-load	8(f)
Brewster	Midwest	Jackson Co., MN	6	94-99	Wind	Base-load	6(f)
Wolf	Midwest	Nobles Co., MN	5	99	Wind	Base-load	6(f)
CP Windfarm	Midwest	Faribault Co., MN	2		Wind	Base-load	4
Blue Breezes	Midwest	Faribault Co., MN	2		Wind	Base-load	3
Cowell	Midwest	Pipestone Co., MN	1	99	Wind	Base-load	2(f)
Solar Ohio	Midwest	Toledo, OH	2		Solar	Base-load	1
Southeast Chicago	Midwest	Chicago, IL	8		Gas	Peaking	296
Total Midwest							12,055
Whitetail	ERCOT	Laredo, TX	57		Wind	Base-load	91
Wolf Hollow 1, 2, 3	ERCOT	Granbury, TX	3		Gas	Intermediate	704
Mountain Creek 8	ERCOT	Dallas, TX	1		Gas	Intermediate	565
Colorado Bend	ERCOT	Wharton, TX	1		Gas	Intermediate	498
Quail Run	ERCOT	Odessa, TX	1		Gas	Intermediate	488
Handley 3	ERCOT	Fort Worth, TX	1		Gas	Intermediate	395
Handley 4, 5	ERCOT	Fort Worth, TX	2		Gas	Peaking	870
Mountain Creek 6, 7	ERCOT	Dallas, TX	2		Gas	Peaking	240
LaPorte	ERCOT	Laporte, TX	4		Gas	Peaking	152
Total ERCOT							4,003
Holyoke Solar	New England	Various	2		Solar	Base-load	5
Solar Massachusetts	New England	Various	5		Solar	Base-load	3
Solar Net Metering	New England	Uxbridge, MA	1		Solar	Base-load	2
Solar Connecticut	New England	Various	2		Solar	Base-load	1
Mystic 8, 9	New England	Charlestown, MA	2		Gas	Intermediate	1,418
Fore River	New England	North Weymouth, MA	1		Gas	Intermediate	726
Mystic 7	New England	Charlestown, MA	1		Oil/Gas	Intermediate	575
Wyman	New England	Yarmouth, ME	1	5.9	Oil	Intermediate	36(f)
Medway	New England	West Medway, MA	3		Oil/Gas	Peaking	117
Framingham	New England	Framingham, MA	3		Oil	Peaking	33
New Boston	New England	South Boston, MA	1		Oil	Peaking	16
Mystic Jet	New England	Charlestown, MA	1		Oil	Peaking	9
Total New England							2,941
Nine Mile Point	New York	Scriba, NY	2	50.01(h)	Uranium	Base-load	833(f)(h)
Ginna	New York	Ontario, NY	1	50.01	Uranium	Base-load	288(f)(h)
Total New York							1,121
AVSR	Other	Lancaster, CA	1		Solar	Base-load	198(g)
Shooting Star	Other	Greensburg, KS	65		Wind	Base-load	104
Exelon Wind 4	Other	Gruver, TX	38		Wind	Base-load	80
Bluegrass Ridge	Other	King City, MO	27		Wind	Base-load	57
Conception	Other	Barnard, MO	24		Wind	Base-load	50
Cow Branch	Other	Rock Port, MO	24		Wind	Base-load	50
Mountain Home	Other	Glenns Ferry, ID	20		Wind	Base-load	42
High Mesa	Other	Elmore Co., ID	19		Wind	Base-load	40
Echo 1	Other	Echo, OR	21	99	Wind	Base-load	35(f)
Sacramento PV Energy	Other	Sacremento, CA	4		Solar	Base-load	30
Cassia	Other	Buhl, ID	14		Wind	Base-load	29
Wildcat	Other	Lovington, NM	13		Wind	Base-load	27

Sunnyside	Other	Sunnyside, UT	1	50	Waste Coal	Base-load	26(f)
Echo 2	Other	Echo, OR	10		Wind	Base-load	20

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
Tuana Springs	Other	Hagerman, ID	8		Wind	Base-load	17
Greensburg	Other	Greensburg, KS	10		Wind	Base-load	13
Echo 3	Other	Echo, OR	6	99	Wind	Base-load	10[f]
Exelon Wind 1	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 2	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 3	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 5	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 6	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 7	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 8	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 9	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 10	Other	Dumas, TX	8		Wind	Base-load	10
Exelon Wind 11	Other	Dumas, TX	8		Wind	Base-load	10
High Plains	Other	Panhandle, TX	8	99.5	Wind	Base-load	10[f]
Threemile Canyon	Other	Boardman, OR	6		Wind	Base-load	10
Solar Arizona	Other	Various	20		Solar	Base-load	29
Outback Solar	Other	Christmas Valley, OR	1		Solar	Base-load	6
Loess Hills	Other	Rock Port, MO	4		Wind	Base-load	5
Denver Airport Solar	Other	Denver, CO	1		Solar	Base-load	4
California PV Energy	Other	Ontario, CA	2		Solar	Base-load	3
Solar California	Other	Various	4		Solar	Base-load	2
Hillabee	Other	Alexander City, AL	1		Gas	Intermediate	670
Malacha	Other	Muck Valley, CA	1	50	Hydroelectric	Intermediate	15[f][i]
West Valley	Other	Salt Lake City, UT	5		Gas	Peaking	185
Grand Prairie	Other	Alberta, Canada	1		Gas	Peaking	75
SEGS 4, 5, 6	Other	Boron, CA	3	4.2-12.2	Solar	Peaking	8[f]
Total Other							1,950
Total							35,137

(a) All nuclear stations are boiling water reactors except Braidwood, Byron, Calvert Cliffs, Ginna, Salem and Three Mile Island, which are pressurized water reactors.
(b) 100%, unless otherwise indicated.
(c) Base-load units are plants that normally operate to take all or part of the minimum continuous load of a system and, consequently, produce electricity at an essentially constant rate. Intermediate units are plants that normally operate to take load of a system during the daytime higher load hours and, consequently, produce electricity by cycling on and off daily. Peaking units consist of lower-efficiency, quick response steam units, gas turbines and diesels normally used during the maximum load periods.
(d) For nuclear stations, capacity reflects the annual mean rating. Fossil stations reflect a summer rating. Wind and solar facilities reflect name plate capacity.
(e) Generation has agreed to permanently cease generation operation at Oyster Creek by December 31, 2019.
(f) Net generation capacity is stated at proportionate ownership share.
(g) Expected capacity upon project completion is 230MW. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(h) Reflects Generation s 50.01% interest in CENG, a joint venture with EDF. For Nine Mile Point, the co-owner owns 18% of Unit 2. Thus Exelon s ownership is 50.01% of 82% of Nine Mile Point Unit 2. Generation also has a unit-contingent PPA with CENG under which it purchases 85% of the nuclear plant output owned by CENG that is not sold to third parties under the pre-existing PPAs through 2014.
(i) In February 2014, Generation sold its remaining stake in Malacha.

The net generation capability available for operation at any time may be less due to regulatory restrictions, transmission congestion, fuel restrictions, efficiency of cooling facilities, level of water supplies or generating units being temporarily out of service for inspection, maintenance, refueling, repairs or modifications required by regulatory authorities.

Generation maintains property insurance against loss or damage to its principal plants and properties by fire or other perils, subject to certain exceptions. For additional information regarding nuclear insurance of generating facilities, see ITEM 1. Business Generation. For its insured losses, Generation is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on Generation s consolidated financial condition or results of operations.

ComEd

ComEd s electric substations and a portion of its transmission rights of way are located on property that ComEd owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. ComEd believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements, licenses and franchise rights; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

ComEd s higher voltage electric transmission lines owned and in service at December 31, 2013 were as follows:

Voltage (Volts)	Circuit Miles
765,000	90
345,000	2,642
138,000	2,292

ComEd s electric distribution system includes 35,491 circuit miles of overhead lines and 30,626 circuit miles of underground lines.

First Mortgage and Insurance

The principal properties of ComEd are subject to the lien of ComEd s Mortgage dated July 1, 1923, as amended and supplemented, under which ComEd s First Mortgage Bonds are issued.

ComEd maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, ComEd is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of ComEd.

PECO

PECO s electric substations and a significant portion of its transmission lines are located on property that PECO owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. PECO believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

PECO s high voltage electric transmission lines owned and in service at December 31, 2013 were as follows:

Voltage (Volts)	Circuit Miles
500,000	188[(a)]
230,000	548
138,000	156
69,000	200

(a) In addition, PECO has a 22.00% ownership interest in 127 miles of 500 kV lines located in Pennsylvania and a 42.55% ownership interest in 131 miles of 500 kV lines located in Delaware and New Jersey.

PECO s electric distribution system includes 12,989 circuit miles of overhead lines and 8,915 circuit miles of underground lines.

Gas

The following table sets forth PECO s natural gas pipeline miles at December 31, 2013:

	Pipeline Miles
Transmission	31
Distribution	6,764
Service piping	6,068
Total	12,863

PECO has an LNG facility located in West Conshohocken, Pennsylvania that has a storage capacity of 1,200 mmcf and a send-out capacity of 157 mmcf/day and a propane-air plant located in Chester, Pennsylvania, with a tank storage capacity of 1,980,000 gallons and a peaking capability of 25 mmcf/day. In addition, PECO owns 31 natural gas city gate stations and direct pipeline customer delivery points at various locations throughout its gas service territory.

First Mortgage and Insurance

The principal properties of PECO are subject to the lien of PECO s Mortgage dated May 1, 1923, as amended and supplemented, under which PECO s first and refunding mortgage bonds are issued.

PECO maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, PECO is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of PECO.

BGE

BGE s electric substations and a significant portion of its transmission lines are located on property that BGE owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. BGE believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

BGE s high voltage electric transmission lines owned and in service at December 31, 2013 were as follows:

Voltage (Volts)	**Circuit Miles**
500,000	218
230,000	322
138,000	54
115,000	697

BGE s electric distribution system includes 9,391 circuit miles of overhead lines and 15,933 circuit miles of underground lines.

Gas

The following table sets forth BGE s natural gas pipeline miles at December 31, 2013:

	Pipeline Miles
Transmission	163
Distribution	7,054
Service piping	6,146
Total	13,363

BGE has an LNG facility located in Baltimore, Maryland that has a storage capacity of 1,055 mmcf and a send-out capacity of 332 mmcf/day, an LNG facility located in Westminster, Maryland that has a storage capacity of 6 mmcf and a send-out capacity of 6 mmcf/day, and a propane-air plant located in Baltimore, Maryland, with a storage capacity of 546 mmcf and a send-out capacity of 85 mmcf/day. In addition, BGE owns 12 natural gas city gate stations and 20 direct pipeline customer delivery points at various locations throughout its gas service territory.

Property Insurance

BGE owns its principal headquarters building located in downtown Baltimore. BGE maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, BGE is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of BGE.

Exelon

Security Measures

The Registrants have initiated and work to maintain security measures. On a continuing basis, the Registrants evaluate enhanced security measures at certain critical locations, enhanced response and recovery plans, long-term design changes and redundancy measures. Additionally, the energy industry has strategic relationships with governmental authorities to ensure that emergency plans are in place and critical infrastructure vulnerabilities are addressed in order to maintain the reliability of the country s energy systems.

ITEM 3. LEGAL PROCEEDINGS

Exelon, Generation, ComEd, PECO and BGE

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES

Exelon, Generation, ComEd, PECO and BGE

Not Applicable to the Registrants.

PART II

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

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Exelon

Exelon s common stock is listed on the New York Stock Exchange. As of January 31, 2014, there were 857,419,806 shares of common stock outstanding and approximately 129,928 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:

	2013				2012			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 30.59	$ 32.42	$ 37.80	$ 34.56	$ 37.50	$ 39.82	$ 39.37	$ 43.70
Low price	26.64	29.42	29.84	29.10	28.40	34.54	36.27	38.31
Close	27.39	29.64	30.88	34.48	29.74	35.58	37.62	39.21
Dividends	0.310	0.310	0.310	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 2009 through 2013.

This performance chart assumes:

- $100 invested on December 31, 2008 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and
- All dividends are reinvested.

Generation

As of January 31, 2014, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2014, there were 127,016,904 outstanding shares of common stock, $12.50 par value, of ComEd, of which 127,002,904 shares were indirectly held by Exelon. At January 31, 2014, in addition to Exelon, there were 294 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

PECO

As of January 31, 2014, there were 170,478,507 outstanding shares of common stock, without par value, of PECO, all of which were indirectly held by Exelon.

BGE

As of January 31, 2014, there were 1,000 outstanding shares of common stock, without par value, of BGE, all of which were indirectly held by Exelon.

Exelon, Generation, ComEd, PECO and BGE

Dividends

Under applicable Federal law, Generation, ComEd, PECO and BGE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Generation, ComEd, PECO or BGE 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 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.

BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE s equity ratio would be below 48% as calculated pursuant to the MDPSC s ratemaking precedents or (b) BGE s senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE s preference stock have not been paid.

At December 31, 2013, Exelon had retained earnings of $10,358 million, including Generation s undistributed earnings of $3,613 million, ComEd s retained earnings of $750 million consisting of retained earnings appropriated for future dividends of $2,389 million, partially offset by $1,639 million of unappropriated retained deficits, PECO s retained earnings of $649 million, and BGE s retained earnings of $1,005 million.

The following table sets forth Exelon s quarterly cash dividends per share paid during 2013 and 2012:

	2013				2012			
(per share)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Exelon	$ 0.310	$ 0.310	$ 0.310	$ 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:

	2013				2012			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$ 75	$ 76	$ 263	$ 211	$ 242	$ 493	$ 291	$ 600
ComEd	55	55	55	55	10	10	10	75
PECO	83	83	83	83	85	86	85	87

First Quarter 2014 Dividend. On January 28, 2014, the Exelon Board of Directors declared a first quarter 2014 regular quarterly dividend of $0.31 per share on Exelon s common stock payable on March 10, 2014, to shareholders of record of Exelon at the end of the day on February 14, 2014.

ITEM 6. SELECTED FINANCIAL DATA

Exelon

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 ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

	For the Years Ended December 31,				
(In millions, except per share data)	2013	2012 [a]	2011	2010	2009
Statement of Operations data:					
Operating revenues	$ 24,888	$ 23,489	$ 19,063	$ 18,644	$ 17,318
Operating income	3,656	2,380	4,479	4,726	4,750
Income from continuing operations	1,729	1,171	2,499	2,563	2,706
Income from discontinued operations					1

Net income	1,729	1,171	2,499	2,563	2,707
Earnings per average common share (diluted):					
Income from continuing operations	$ 2.00	$ 1.42	$ 3.75	$ 3.87	$ 4.09
Net income	$ 2.00	$ 1.42	$ 3.75	$ 3.87	$ 4.09
Dividends per common share	$ 1.46	$ 2.10	$ 2.10	$ 2.10	$ 2.10
Average shares of common stock outstanding diluted	860	819	665	663	662

(a) The 2012 financial results only include the operations of Constellation and BGE from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012.

(In millions)	2013	2012	December 31, 2011	2010	2009
Balance Sheet data:					
Current assets	$ 10,137	$ 10,140	$ 5,713	$ 6,398	$ 5,441
Property, plant and equipment, net	47,330	45,186	32,570	29,941	27,341
Noncurrent regulatory assets	5,910	6,497	4,518	4,140	4,872
Goodwill	2,625	2,625	2,625	2,625	2,625
Other deferred debits and other assets	13,922	14,113	9,569	9,136	8,901
Total assets	$ 79,924	$ 78,561	$ 54,995	$ 52,240	$ 49,180
Current liabilities	$ 7,728	$ 7,791	$ 5,134	$ 4,240	$ 4,238
Long-term debt, including long-term debt to financing trusts	18,271	18,346	12,189	12,004	11,385
Noncurrent regulatory liabilities	4,388	3,981	3,627	3,555	3,492
Other deferred credits and other liabilities	26,597	26,626	19,570	18,791	17,338
Preferred securities of subsidiary		87	87	87	87
Non-controlling interest	15	106	3	3	
BGE preference stock not subject to mandatory redemption	193	193			
Shareholders equity	22,732	21,431	14,385	13,560	12,640
Total liabilities and shareholders equity	$ 79,924	$ 78,561	$ 54,995	$ 52,240	$ 49,180

Generation

The selected financial data presented below has been derived from the audited consolidated financial statements of Generation. This data is qualified in its entirety by reference to and should be read in conjunction with Generation s Consolidated Financial Statements and ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

(In millions)	2013	For the Years Ended December 31, 2012 [(a)]	2011	2010	2009
Statement of Operations data:					
Operating revenues	$ 15,630	$ 14,437	$ 10,447	$ 10,025	$ 9,703
Operating income	1,664	1,120	2,875	3,046	3,295
Net income	1,060	558	1,771	1,972	2,122

(a) The 2012 financial results only include the operations of Constellation from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012.

(In millions)	2013	2012	December 31, 2011	2010	2009
Balance Sheet data:					
Current assets	$ 6,439	$ 6,211	$ 3,217	$ 3,087	$ 3,360
Property, plant and equipment, net	20,111	19,531	13,475	11,662	9,809
Other deferred debits and other assets	14,682	14,939	10,741	9,785	9,237

Total assets	$ 41,232	$ 40,681	$ 27,433	$ 24,534	$ 22,406
Current liabilities	$ 3,867	$ 4,097	$ 2,144	$ 1,843	$ 2,262
Long-term debt	7,168	7,455	3,674	3,676	2,967
Other deferred credits and other liabilities	17,455	16,464	12,907	11,838	10,385
Non-controlling interest	17	108	5	5	2
Member s equity	12,725	12,557	8,703	7,172	6,790
Total liabilities and member s equity	$ 41,232	$ 40,681	$ 27,433	$ 24,534	$ 22,406

ComEd

The selected financial data presented below has been derived from the audited consolidated financial statements of ComEd. This data is qualified in its entirety by reference to and should be read in conjunction with ComEd s Consolidated Financial Statements and ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

	For the Years Ended December 31,				
(In millions)	**2013**	**2012**	**2011**	**2010**	**2009**
Statement of Operations data:					
Operating revenues	$ 4,464	$ 5,443	$ 6,056	$ 6,204	$ 5,774
Operating income	954	886	982	1,056	843
Net income	249	379	416	337	374

	December 31,				
(In millions)	**2013**	**2012**	**2011**	**2010**	**2009**
Balance Sheet data:					
Current assets	$ 1,540	$ 1,775	$ 2,188	$ 2,151	$ 1,579
Property, plant and equipment, net	14,666	13,826	13,121	12,578	12,125
Goodwill	2,625	2,625	2,625	2,625	2,625
Noncurrent regulatory assets	933	666	699	947	1,096
Other deferred debits and other assets	4,354	4,013	4,005	3,351	3,272
Total assets	$ 24,118	$ 22,905	$ 22,638	$ 21,652	$ 20,697
Current liabilities	$ 2,048	$ 1,655	$ 2,071	$ 2,134	$ 1,597
Long-term debt, including long-term debt to financing trusts	5,264	5,521	5,421	4,860	4,704
Noncurrent regulatory liabilities	3,512	3,229	3,042	3,137	3,145
Other deferred credits and other liabilities	5,766	5,177	5,067	4,611	4,369
Shareholders equity	7,528	7,323	7,037	6,910	6,882
Total liabilities and shareholders equity	$ 24,118	$ 22,905	$ 22,638	$ 21,652	$ 20,697

PECO

The selected financial data presented below has been derived from the audited consolidated financial statements of PECO. This data is qualified in its entirety by reference to and should be read in conjunction with PECO s Consolidated Financial Statements and ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

	For the Years Ended December 31,				
(In millions)	**2013**	**2012**	**2011**	**2010**	**2009**
Statement of Operations data:					
Operating revenues	$ 3,100	$ 3,186	$ 3,720	$ 5,519	$ 5,311
Operating income	666	623	655	661	697
Net income	395	381	389	324	353
Net income on common stock	388	377	385	320	349

(In millions)	2013	2012	December 31, 2011	2010	2009
Balance Sheet data:					
Current assets	$ 906	$ 1,094	$ 1,243	$ 1,670	$ 1,006
Property, plant and equipment, net	6,384	6,078	5,874	5,620	5,297
Noncurrent regulatory assets	1,448	1,378	1,216	968	1,834
Other deferred debits and other assets	879	803	823	727	882
Total assets	$ 9,617	$ 9,353	$ 9,156	$ 8,985	$ 9,019
Current liabilities	$ 891	$ 1,158	$ 1,145	$ 1,163	$ 939
Long-term debt, including long-term debt to financing trusts	2,131	1,831	1,781	2,156	2,405
Noncurrent regulatory liabilities	629	538	585	418	317
Other deferred credits and other liabilities	2,901	2,757	2,620	2,278	2,706
Preferred securities		87	87	87	87
Shareholders equity	3,065	2,982	2,938	2,883	2,565
Total liabilities and shareholders equity	$ 9,617	$ 9,353	$ 9,156	$ 8,985	$ 9,019

BGE

The selected financial data presented below has been derived from the audited consolidated financial statements of BGE. This data is qualified in its entirety by reference to and should be read in conjunction with BGE s Consolidated Financial Statements and ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

(In millions)	2013	For the Years Ended December 31, 2012	2011	2010	2009
Statement of Operations data:					
Operating revenues	$ 3,065	$ 2,735	$ 3,068	$ 3,541	$ 3,646
Operating income	449	132	314	350	268
Net income	210	4	136	147	91
Net income (loss) attributable to common shareholder	197	(9)	123	134	78

(In millions)	2013	2012 [(a)]	December 31, 2011 [(a)]	2010 [(a)]	2009 [(a)]
Balance Sheet data:					
Current assets	$ 1,011	$ 980	$ 969	$ 1,012	$ 1,205
Property, plant and equipment, net	5,864	5,498	5,132	4,754	4,470
Noncurrent regulatory assets	524	522	551	566	602
Other deferred debits and other assets	462	506	551	545	386
Total assets	$ 7,861	$ 7,506	$ 7,203	$ 6,877	$ 6,663
Current liabilities	$ 827	$ 980	$ 734	$ 728	$ 753
Long-term debt, including long-term debt to financing trusts and variable interest entities	2,199	1,969	2,186	2,060	2,141
Noncurrent regulatory liabilities	204	214	201	192	188
Other deferred credits and other liabilities	2,076	1,985	1,781	1,634	1,434
Preference stock not subject to mandatory redemption	190	190	190	190	190
Shareholders equity	2,365	2,168	2,111	2,073	1,939
Non-controlling interest					18

Total liabilities and shareholders equity	$ 7,861	$ 7,506	$ 7,203	$ 6,877	$ 6,663

(a) BGE retrospectively reclassified certain regulatory assets and regulatory liabilities to conform to the current year presentation.

Item 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Exelon

Executive Overview

Exelon, a utility services holding company, operates through the following principal subsidiaries:

Generation, whose integrated business consists of owned, contracted and investments in electric generating facilities managed through customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities.

ComEd, whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.

PECO, whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.

BGE, whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Exelon has nine reportable segments consisting of Generation s six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions in Generation), ComEd, PECO and BGE. See Note 24 of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon s reportable segments.

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

Exelon s consolidated financial information includes the results of its four separate operating subsidiary registrants, Generation, ComEd, PECO and BGE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management s Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO and BGE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Financial Results. The following consolidated financial results reflect the results of Exelon for year ended December 31, 2013 compared to the same period in 2012. The 2012 financial results only include the operations of Constellation and BGE from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012. All amounts presented below are before the impact of income taxes, except as noted.

Results in 2013 were unfavorably impacted at Generation by continuing declines in realized power and gas prices, in part driven by the abundance of natural gas supply, continued sluggish demand and subsidized renewable generation; only partially offset by improved returns at the utilities, and the realization of additional post-merger synergies and operational excellence across all businesses. Generation s financial results continue to be challenged by low natural gas prices, and by the impacts of excess generation from subsidized renewable energy, flat load growth and distorted market designs, especially in its Midwest markets.

	The Years Ended December 31,							Favorable
	2013						2012	(Unfavorable)
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon	Variance
Operating revenues	$ 15,630	$ 4,464	$ 3,100	$ 3,065	$ (1,371)	$ 24,888	$ 23,489	$ 1,399
Purchased power and fuel	8,197	1,174	1,300	1,421	(1,368)	10,724	10,157	(567)
Revenue net of purchased power and fuel (a)	7,433	3,290	1,800	1,644	(3)	14,164	13,332	832
Other operating expenses								
Operating and maintenance	4,534	1,368	748	634	(14)	7,270	7,961	691
Depreciation and amortization	856	669	228	348	52	2,153	1,881	(272)
Taxes other than income	389	299	158	213	36	1,095	1,019	(76)
Total other operating expenses	5,779	2,336	1,134	1,195	74	10,518	10,861	343
Equity in earnings/(losses) of unconsolidated affiliates	10					10	(91)	101
Operating income	1,664	954	666	449	(77)	3,656	2,380	1,276
Other income and (deductions)								
Interest expense, net	(357)	(579)	(115)	(122)	(183)	(1,356)	(928)	(428)
Other, net	368	26	6	17	56	473	346	127
Total other income and (deductions)	11	(553)	(109)	(105)	(127)	(883)	(582)	(301)
Income (loss) before income taxes	1,675	401	557	344	(204)	2,773	1,798	975
Income taxes	615	152	162	134	(19)	1,044	627	(417)
Net income (loss)	1,060	249	395	210	(185)	1,729	1,171	558
Net (loss) income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	(10)		7	13		10	11	1
Net income (loss) on common stock	$ 1,070	$ 249	$ 388	$ 197	$ (185)	$ 1,719	$ 1,160	$ 559

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

Exelon s net income on common stock was $1,719 million for the year ended December 31, 2013 as compared to $1,160 million for the year ended December 31, 2012, and diluted earnings per average common share were $ 2.00 for the year ended December 31, 2013 as compared to $1.42 for the year ended December 31, 2012.

Operating revenues net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $832 million as compared to 2012. The year-over-year increase in operating revenue net of purchased power and fuel expense reflects the inclusion of Constellation and BGE s results for the full period in 2013 and was primarily due to the following favorable factors:

Decrease in Generation s amortization expense for the acquired energy contracts recorded at fair value at the merger date of $610 million;

Increase in BGE s revenue net of purchased power and fuel expense of $278 million, primarily as a result of the inclusion of BGE s results for the full period in 2013, accrual of the residential customer rate credit that was a condition of the MDPSC s approval of Exelon s merger with Constellation in 2012, and the impact of the MDPSC approved electric and natural gas distribution rate increases that became effective February 23, 2013;

Increase in Generation s revenue net of purchased power and fuel of $159 million on other activities, including proprietary trading, retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of customer sited solar facilities, primarily due to the addition of Constellation; and

Increase in ComEd s revenue net of purchased power expense of $154 million primarily due to increased distribution revenue due to recovery of increased costs and capital investment and higher allowed ROE pursuant to the formula rate under EIMA and the enactment of Senate Bill 9.

The year-over-year increase in operating revenue net of purchased power and fuel expense was partially offset by the following unfavorable factors:

Decrease in Generation s electric revenue net of purchased power and fuel expense of $565 million primarily due to lower realized energy prices, lower load volume and increased nuclear fuel expense, partially offset by higher capacity revenue, increased nuclear volumes, and lower energy supply costs as a result of the integration of the energy generation and load serving businesses following the merger;

Reduced revenue net of purchased power and fuel at Generation of $136 million in 2013 associated with the Maryland Clean Coal assets that were sold in November 2012 and lost compensation on the reliability-must-run program with PJM for retired fossil generating assets that expired on May 31, 2012; and

Decrease in PECO s revenue net of purchased power and fuel expense of $11 million primarily due to the decrease in effective rates due to increased usage per customer across all customer classes, decreased cost recovery for energy efficiency and demand response programs, decreased gross receipts tax revenue, and the customer refund in 2013 of the tax cash benefit related to gas property distribution repairs.

Operating and maintenance expense decreased by $691 million as compared to 2012 primarily due to the following favorable factors:

Decrease in operating and maintenance expense associated with the generating assets retired or divested during 2012 of $442 million;

Costs incurred in March 2012 of $216 million and $195 million as part of the Maryland order approving the merger and a settlement with the FERC, respectively;

Decrease in Constellation merger and integration costs of $201 million in 2013; and

Decrease in uncollectible accounts expense of $58 million at ComEd resulting from the timing of regulatory cost recovery and customers purchasing electricity from competitive electric generation suppliers.

The year-over-year decrease in operating and maintenance expense was partially offset by the following unfavorable factors:

Increase in labor, other benefits, contracting and materials costs of $298 million, primarily due to the addition of BGE and Constellation for the full period in 2013; and

Long-lived asset impairments and related charges of $174 million in 2013, primarily related to Generation s cancellation of nuclear uprate projects and the impairment of certain wind generating assets.

Depreciation and amortization expense increased by $272 million primarily due to the addition of BGE and Constellation for the full period in 2013, BGE s and Constellation s plant balances in 2012, ongoing capital expenditures across the operating companies, the completion of wind and solar facilities placed into service in the second half of 2012 and in 2013 at Generation, and increased regulatory asset amortization related to higher MGP remediation expenditures and higher costs for energy efficiency and demand response programs at ComEd and BGE, respectively.

The favorable increase in Equity in earnings/loss of unconsolidated affiliates of $101 million was primarily due to higher net income from Generation s equity investment in CENG in 2013 compared to the same period in 2012 and lower amortization of the basis difference of Generation s ownership interest in CENG recorded at fair value in connection with the merger.

Interest expense increased by $428 million primarily due to an increase in interest expense at ComEd related to the remeasurement of Exelon s like-kind exchange tax position in the first quarter of 2013, an increase in debt obligations as a result of the merger and an increase in project financing at Generation in 2013.

Exelon s effective income tax rates for the years ended December 31, 2013 and 2012 were 37.6% and 34.9%, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the years ended December 31, 2013 and 2012, 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, 2013 were $2,149 million, or $2.50 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,330 million, or $2.85 per diluted share, for the same period in 2012. 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, 2013 as compared to 2012:

	December 31,			
	2013		2012	
(All amounts after tax; in millions, except per share amounts)		**Earnings per Diluted Share**		**Earnings per Diluted Share**
Net Income	$ 1,719	$ 2.00	$ 1,160	$ 1.42
Mark-to-Market Impact of Economic Hedging Activities [a]	(310)	(0.35)	(310)	(0.38)
Unrealized Net Gains Related to NDT Fund Investments [b]	(78)	(0.09)	(56)	(0.07)
Plant Retirements and Divestitures [c]	(13)	(0.02)	236	0.29
Asset Retirement Obligation [d]	7	0.01	1	
Merger and Integration Costs [e]	87	0.08	257	0.31
Other Acquisition Costs [f]			3	
Reassessment of State Deferred Income Taxes [g]	4		(117)	(0.14)
Amortization of Commodity Contract Intangibles [h]	347	0.41	758	0.93
Amortization of the Fair Value of Certain Debt [i]	(7)	(0.01)	(9)	(0.01)
Remeasurement of Like-Kind Exchange Tax Position [j]	267	0.31		
Long-Lived Asset Impairment [k]	110	0.14		
Maryland Commitments [l]			227	0.28
FERC Settlement [m]			172	0.21
Midwest Generation Bankruptcy Charges [n]	16	0.02	8	0.01
Adjusted (non-GAAP) Operating Earnings	$ 2,149	$ 2.50	$ 2,330	$ 2.85

(a) Reflects the impact of (gains) losses for the years ended December 31, 2013 and 2012, respectively, on Generation s economic hedging activities (net of taxes of $201 million and $200 million, respectively). In order to better align the impacts of economic hedging with the underlying business activity (e.g. the sale of power and/or the use of fuel), these unrealized (gains) losses are excluded from operating earnings until the transactions are realized. See Note 12 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation s hedging activities.

(b) Reflects the impact of unrealized gains for the years ended December 31, 2013 and 2012, respectively, on Generation s NDT fund investments for Non-Regulatory Agreement Units (net of taxes of $(144) million and $(132) million, respectively). See Note 15 Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation s NDT fund investments.

(c) Reflects the impacts associated with the sale or retirement of generating stations in the years ended December 31, 2013 and 2012 (net of taxes of $4 million and $106 million, respectively). See Results of Operations Generation for additional detail related to the generating unit retirements.

(d) Primarily reflects the impact of an increase in Generation s asset retirement obligation for asbestos at retired fossil plants for the year ended December 31, 2013 (net of taxes of $(5) million). Primarily reflects the impact of an increase in Generation s decommissioning obligation for spent nuclear fuel at retired nuclear units for the year ended December 31, 2012 (net of taxes of $(1) million).

(e) Reflects certain costs incurred in the years ended December 31, 2013 and 2012 (net of taxes of $33 million and $161 million, respectively) associated with the merger, including employee-related expenses (e.g. severance, retirement, relocation and retention bonuses) integration initiatives, certain pre-acquisition contingencies, and CENG transaction costs, partially offset in 2013 by a one-time benefit pursuant to the BGE 2012 electric and gas distribution rate case order for the recovery of previously incurred integration costs. See Note 4 Merger and Acquisitions of the Combined Notes to the Consolidated Financial Statements for additional information.

(f) Reflects certain costs incurred in the year ended 2012 associated with various acquisitions (net of taxes of $2 million).

(g) Reflects the non-cash impacts of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment in 2013 and as a result of the merger in 2012. See Note 14 Income Taxes of the Combined Notes to the Consolidated Financial Statements for additional information.

(h) Reflects the non-cash impact for the years ended December 31, 2013 and 2012 (net of taxes of $219 million and $491 million, respectively) of the amortization of intangible assets, net, related to commodity contracts recorded at fair value at the Constellation merger date. See Note 4 Merger and Acquisitions of the Combined Notes to the Consolidated Financial Statements for additional information.

(i) Reflects the non-cash amortization of certain debt for the years ended December 31, 2013 and 2012 (net of taxes of $5 million and $6 million, respectively) recorded at fair value at the Constellation merger date which was retired in the second quarter of 2013. See Note 4 Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.
(j) Reflects a non-cash charge to earnings for the year ended December 31, 2013 (net of taxes of $102 million) resulting from the first quarter 2013 remeasurement of a like-kind exchange tax position taken on ComEd s 1999 sale of fossil generating assets. See Note 14 of the Combined Notes to the Consolidated Financial statements for additional information.
(k) Reflects 2013 impairment and related charges to earnings for the year ended December 31, 2013 (net of taxes of $69 million) primarily related to Generation s cancellation of nuclear uprate projects and the impairment of certain wind generating assets.
(l) Reflects costs incurred for the year ended December 31, 2012 associated with the Constellation merger (net of taxes of $101 million) as part of the Maryland order approving the merger transaction. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(m) Reflects costs incurred for the year ended December 31, 2012 (net of taxes of $23 million) as part of a settlement with the FERC to resolve a dispute related to Constellation s pre-merger hedging and risk management transactions. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information.
(n) Reflects costs incurred to establish estimated liabilities for the years ended December 31, 2013 and December 31, 2012 (net of taxes of $10 million and $5 million, respectively) pursuant to the Midwest Generation bankruptcy, primarily related to lease payments under a coal rail car lease and estimated payments for asbestos-related personal injury claims.

As discussed above, Exelon has incurred and will continue to incur costs associated with the Constellation merger, including meeting the various commitments set forth by regulators and agreed-upon with other interested parties as part of the merger approval process, and integrating the former Constellation businesses into Exelon.

For the year ended December 31, 2013, expense has been recognized for costs incurred to achieve the merger, prior to consideration of regulatory accounting treatment, as follows:

	Pre-tax Expense Twelve Months Ended December 31, 2013				
Merger and Integration Costs:	**Generation [a]**	**ComEd**	**PECO**	**BGE [a]**	**Exelon [a]**
Employee-Related [b]	48	4	3	1	58
Other [c]	58	12	6	5	84
Total	$ 106	$ 16	$ 9	$ 6	$ 142

	Pre-tax Expense Twelve Months Ended December 31, 2012				
Merger and Integration Costs:	**Generation**	**ComEd**	**PECO**	**BGE [a]**	**Exelon [a]**
Maryland Commitments	35			139	328
Employee-Related [b]	138	24	11	24	207
Other [c]	167	17	6	7	211
Transaction [d]	$	$	$	$	$ 58
Total	$ 340	$ 41	$ 17	$ 170	$ 804

(a) For Exelon, Generation and BGE, includes the operations of the acquired businesses from the date of the merger March 12, 2012 through the year ended December 31, 2013.
(b) Costs primarily for employee severance, pension and OPEB expense and retention bonuses. ComEd established regulatory assets of $2 million and $21 million for the years ended December 31, 2013 and December 31, 2012, respectively. BGE established regulatory assets of $0 million and $22 million for the years ended December 31, 2013 and December 31, 2012, respectively. The majority of these costs are expected to be recovered over a five-year period.
(c) Costs to integrate Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. ComEd established a regulatory asset of $9 million and $15 million for the years ended December 31, 2013 and December 31, 2012, respectively, for certain other merger and integration costs. BGE established a regulatory asset of $12 million and $0 million for the years ended December 31, 2013 and December 31, 2012, respectively, for certain other merger and integration costs.
(d)

External, third-party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of the transaction.

As of December 31, 2013, Exelon expects to incur total additional Constellation merger-related expenses in 2014 and 2015 of approximately $34 million.

Pursuant to the conditions set forth by the MDPSC in its approval of the merger transaction, Exelon committed to provide a package of benefits to BGE customers, and make certain investments in the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion. The direct investment includes $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for Generation s competitive energy businesses. On March 20, 2013, Generation signed a twenty-year lease agreement that is contingent upon the developer obtaining financing for the construction of the building. Once required approvals are received and financing condition is satisfied, construction of the building will commence. The building is expected to be ready for occupancy in two years following commencement of construction. The direct investment estimate also includes $625 million in expenditures relating to the development of 285-300 MW of new electric generation facilities in Maryland (expected to be completed over the next ten years).

Exelon s Strategy and Outlook for 2014 and Beyond

Exelon s value proposition and competitive advantage come from its scope and scale across the energy value chain and its core strengths of operational excellence and financial discipline.

On March 12, 2012, the Exelon and Constellation merger was completed. The merger creates incremental strategic value by matching Exelon s clean generation fleet with Constellation s leading customer-facing platform, as well as creating economies of scale through expansion across the energy value chain. Exelon supports customer switching to alternative electric generation suppliers and the addition of Constellation s competitive retail operations provides another outlet for Exelon to grow its business in competitive markets.

Generation s electricity generation strategy is to pursue opportunities that provide generation to load matching and that diversify the generation fleet by expanding Generation s regional and technological footprint. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in wholesale power markets. Generation s customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help mitigate the current challenging conditions in competitive energy markets.

Exelon s utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of best practices to achieve improved operational and financial results. Combined, the utilities plan to invest approximately $15 billion over the next five years in smart meter technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Exelon s financial priorities are to maintain investment grade credit metrics at each of Exelon, Generation, ComEd, PECO and BGE, and to return value to Exelon s shareholders with a sustainable dividend throughout the energy commodity market cycle and through earnings growth from attractive investment opportunities.

In pursuing its strategies, Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the power markets. 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 market prices that Generation can obtain for the output of its power plants, (2) the rate of expansion of subsidized low-carbon generation in the markets in which Generation s output is sold, (3) the effects on energy demand due to factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these market pricing issues.

Power Markets

Price of Fuels. 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 and retail power prices, which results in a reduction in Exelon s revenues. Since the third quarter of 2011, forward natural gas prices for 2014 and 2015 have declined significantly; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Subsidized Generation. The rate of expansion of subsidized low-carbon generation such as wind and solar energy in the markets in which Generation s output is sold can negatively impact wholesale power prices, and in turn, Generation s results of operations.

Various states have implemented or proposed legislation, regulations or other policies to subsidize new generation development, which may result in artificially depressed wholesale energy and capacity prices. For example, the New Jersey legislature enacted into law in January 2011, the Long Term capacity Pilot Program (LCAPP). LCAPP provides eligible generators with 15-year fixed contracts for the sale of capacity in the PJM capacity market. Under LCAPP, the local utilities in New Jersey are required to pay (or receive) the difference between generators receive in the capacity market and the price guaranteed under the 15 year contract. New Jersey ultimately selected three proposals to participate in LCAPP and build new generation in the state. In addition, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland, that it projected will be in commercial operation by June 1, 2015. CPV has subsequently sought to extend that date. The CfD mandates that utilities (including BGE) pay (or receive) the difference between CPV s contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market.

Exelon and others filed a complaint in federal district court challenging the constitutionality and other aspects of the New Jersey legislation. Similarly, Exelon and others are also challenging the selection of the three generation developers in New Jersey state court proceedings and the MDPSC actions in Maryland state court. On October 25, 2013, the U.S. District Court in New Jersey issued a judgment order finding that the New Jersey legislation violates the Supremacy Clause of the United States Constitution and the New Jersey SOCA contract is unenforceable. Similarly, on October 24, 2013, the U.S. District Court in Maryland issued a judgment order finding that the MDPSC s Order directing BGE and two other Maryland electric distribution companies to enter into a CfD violates the Supremacy Clause of the United States Constitution, as described in Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements. In addition, on October 1, 2013, a Maryland State Circuit Court upheld the MDPSC Orders as being within the MDPSC s statutory authority under Maryland state law. This decision is separate from the judgment in the federal litigation that the MDPSC Order is unconstitutional and the CfD unenforceable under federal law. The federal judgment, if upheld, would prevent enforcement of the CfD even if the Circuit Court decision stands. The non-prevailing parties have sought appeals in federal appellate court in both the New Jersey and

Maryland federal litigation. Finally, on October 23, 2013, the New Jersey state court dismissed the New Jersey state proceeding without prejudice, subject to the final outcome of the New Jersey federal litigation.

As required under their contracts, two of the New Jersey generator developers and one in Maryland offered and cleared in PJM s capacity market auctions held in May 2012 and 2013. In addition, CPV has announced its intention to move forward with construction of its New Jersey plant, with or without the challenged state subsidy. Nonetheless to the extent that the state-required customer subsidies are included under their respective contracts, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in these auctions and may continue to do so in future auctions to the detriment of Exelon s market driven position. While the U.S. District Court decisions in Maryland and New Jersey are positive developments, continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR), could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish programs, which could substantially impact Exelon s market driven position and could have a significant effect on Exelon s financial results of operations, financial position and cash flows.

PJM s capacity market rules include a MOPR, which is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. However, as described above, Exelon does not believe that the existing MOPR will work effectively with respect to generator developers who have a state-sponsored subsidy and has concerns with certain other aspects of PJM s rules related to the capacity auction. Accordingly, Exelon is working with other market stakeholders on several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sponsored subsidy contracts, excessive imported capacity resources and certain limited availability demand response resources) cannot inappropriately affect capacity auction prices in PJM.

See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Maryland Order.

Exelon remains active in advocating for competitive markets, opposing policies that ask either taxpayers or consumers to subsidize or give preferential treatment to specific generation providers or technologies, or that would threaten the reliability and value of the integrated electricity grid.

Energy Demand. The continued tepid economic environment and growing energy efficiency initiatives have limited the demand for electricity across each of the Exelon utility companies. ComEd is projecting load volumes to decrease by 0.2% in 2014 compared to 2013, while PECO and BGE are projecting an increase of 0.3% and 0.6%, respectively, in 2014 compared to 2013.

Retail Competition. Generation s retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. Recently, sustained low forward natural gas and power prices and low market volatility have caused retail competitors to aggressively pursue market share, and wholesale generators (including Generation) to use their retail operations to hedge generation output. These factors have adversely affected overall gross margins and profitability in Generation s retail operations.

Strategic Policy Alignment

Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, 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.

Exelon s board of directors declared the first quarter 2013 dividend of $0.525 per share, and in response to low forward energy prices and weaker financial expectations, among other factors, approved a revised dividend policy going forward. The first quarter dividend was paid on March 8, 2013 to shareholders of record on February 19, 2013 and was based on Exelon s previous dividend of $2.10 per share on an annualized basis. The second, third and fourth quarter dividends were based on Exelon s new dividend policy of $0.31 per share quarterly dividend ($1.24 per share on an annualized basis). All future quarterly dividends require approval by Exelon s board of directors.

Exelon and Generation evaluate the economic viability of each of their generating units on an ongoing basis. Decisions regarding the future of economically challenged generating assets will be based primarily on the economics of continued operation of the individual plants. If Exelon and Generation do not see a path to sustainable profitability in any of their plants, Exelon and Generation will take steps to retire those plants to avoid sustained losses. Retirement of plants could materially affect Exelon s and Generation s results of operations, financial position, and cash flows through among other things, potential impairment charges, accelerated depreciation and decommissioning expenses over the plants remaining useful lives, and ongoing reductions to operating revenues, operating and maintenance expenses, and capital expenditures.

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 non-derivative and 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 2014 and 2015. 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. As of December 31, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015, and 2016, 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 economic hedges and certain non-derivative contracts including Generation s sales of energy to ComEd, PECO and BGE relating to their respective retail load obligations. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures coal, oil 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, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation s procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation s uranium concentrate requirements from 2014 through 2018 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. ComEd, PECO and BGE mitigate such exposure through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Growth Opportunities

Exelon is currently pursuing growth in both the utility and generation businesses focused primarily on smart meter and smart grid initiatives at the utilities and on renewables development and the nuclear uprate program at Generation. The utilities also anticipate making significant future investments in infrastructure modernization and improvement initiatives. Management continually evaluates growth opportunities aligned with Exelon s existing businesses in electric and gas distribution, electric transmission, generation, customer supply of electric and natural gas products and services, and natural gas exploration and production activities, leveraging Exelon s expertise in those areas.

Transmission Development Project. Exelon and AEP Transmission Holding Company, LLC (AEP) are working collaboratively to develop an 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 AEP (75%) and RTD (25%). Exelon Transmission Company, LLC and AEP each own 50% of RTD. 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 and scope of the project are dependent on a number of factors, including RTO requirements, interregional transmission planning process requirements, state siting requirements, routing of the line, and equipment and commodity costs. Exelon and AEP are currently pursuing the project and other segments that are electrically equivalent in nature for inclusion in interregional planning process between PJM and MISO; if approved through that process, the project would then need to be approved through the respective planning processes of PJM and MISO.

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 9.9%, 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 11.4%. 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. FERC accepted this filing on March 16, 2012.

Smart Meter and Smart Grid Initiatives.

ComEd s Smart Meter and Smart Grid Investments. ComEd plans to invest approximately $1.3 billion on smart meters and smart grid under EIMA, including $1.0 billion through the AMI Deployment Plan. On June 5, 2013, the ICC issued an interim order approving ComEd s accelerated AMI deployment plan consistent with the provisions of Senate Bill 9. The deployment plan provides for the installation of 4 million electric smart meters, of which more than 60,000 meters were installed by the end of 2013.

PECO s Smart Meter and Smart Grid Investments. In 2010, the PAPUC approved PECO s Smart Meter Procurement and Installation Plan, under which PECO will install more than 1.6 million smart meters. PECO plans to spend up to a total of $595 million and $120 million on its smart meter and smart grid infrastructure, respectively, of which $200 million will be funded by SGIG.

BGE Smart Grid Initiative. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million electric and gas smart meters at an expected total cost of approximately $480 million, before considering the $200 million SGIG for smart grid and other related initiatives.

See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives.

Generation Renewable Development. On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which is developing, building, operating, and maintaining the project. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013. Exelon has been informed by First Solar of issues relating to delays in the certification of certain components relating to the final two blocks of the project, which will delay commercial operation of these two blocks until the first half of 2014. The delay will not have a material financial effect on Exelon. Exelon expects the project to be in full commercial operation in the first half of 2014. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA with Pacific Gas & Electric Company for the full output of the plant, which has been approved by the CPUC. Upon completion, the facility will add 230 MWs to Generation s renewable generation fleet. Total capitalized costs for the facility are expected to be approximately $1.1 billion. Total capitalized costs incurred through December 31, 2013 were approximately $968 million. In addition, Generation constructed and placed into service 400 MWs of additional wind generation in 2012 at a cost of $710 million and another 50 MW will be added to Generation s wind portfolio in 2014 with the expansion of its Beebe project in Michigan, the output of which will be fully contracted under a 20-year PPA.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects. The Measurement Uncertainty Recapture uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. Additionally, the market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. During 2013, Generation recorded a pre-tax charge to operating and maintenance expense and interest expense of approximately $111 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Under the nuclear uprate program, Generation has placed into service projects representing 316 MWs of new nuclear generation at a cost of $952 million, which has been capitalized to property, plant and equipment on Exelon s and Generation s consolidated balance sheets. At December 31, 2013, Generation has capitalized $203 million to construction work in progress within property, plant and equipment for nuclear uprate projects expected to be placed in service by the end of 2016, consisting of 200 MWs of new nuclear generation, that are in the installation phase across four nuclear stations; Peach Bottom in Pennsylvania and Byron, Braidwood and Dresden in Illinois. The remaining spend associated with these projects is expected to be approximately $300 million through the end of 2016. Generation believes that it is probable that these projects will be completed. If a project is expected not to be completed as planned, previously capitalized costs will be reversed through earnings as a charge to operating and maintenance expense and interest.

Liquidity

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.4 billion.

Exposure to Worldwide Financial Markets. Exelon 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, 2013, approximately 30%, or $2.5 billion, of the Registrants aggregate total commitments were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.6 billion was available as of December 31, 2013. There were no borrowings under the Registrants credit facilities as of December 31, 2013. See Note 13 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

February 5, 2014 Winter Ice Storm. On February 5, 2014, a winter storm which brought a mix of snow, ice and freezing rain to the region interrupted electric service delivery to nearly 715,000 customers in PECO s service territory. Restoration efforts are continuing and will include significant costs associated with employee overtime, support from other utilities and incremental equipment, contracted tree trimming crews and supplies. PECO estimates that restoration efforts will result in $60 million to $80 million of incremental operating and maintenance expense and $30 million to $40 million of incremental capital expenditures for the first quarter of 2014.

Tax Matters

See Note 14 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Environmental Legislative and Regulatory Developments.

Exelon supports the promulgation of certain environmental regulations 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 their low emission generation portfolios, Generation and CENG will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the U.S. EPA s rulemaking efforts. The timing of the consideration of such legislation is unknown.

Air Quality. In recent years, the U.S. EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act relating to NAAQS for conventional air pollutants (e.g., NO_x, SO_2 and particulate matter) as well as stricter technology requirements to control HAPs (e.g., acid gases, mercury and other heavy metals) from electric generation units. The U.S. EPA continues to review and update its NAAQS with a tightened particulate matter NAAQS issued in December 2012 and a review of the current 2008 ozone NAAQS that is expected to result in a proposed revision of the ozone NAAQS sometime in fall 2014. These updates will potentially result in more stringent emissions limits on fossil-fuel electric generating stations. There continues to be opposition among fossil-fuel generation owners to the potential stringency and timing of these air regulations.

In July 2011, the U.S. EPA published CSAPR and in June 2012, it issued final technical corrections. CSAPR requires 28 upwind 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 downwind states. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA had exceeded its authority in certain material aspects with respect to CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. Until the U.S. EPA re-issues CSAPR, Exelon cannot determine the impacts of the rule, including any that would impact power prices. In June 2013, the U.S. Supreme Court granted the U.S. EPA s petition to review the D.C. Circuit Court s CSAPR decision. Oral argument was held on December 10, 2013. A decision is expected sometime during 2014.

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 NSPS for electric generating units. The final rule, known as MATS, 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. 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. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon was granted permission by the Court to intervene in support of the rule. A decision by the Court will not occur until 2014. The outcome of the appeal, and its impact on power plant operators investment and retirement decisions, is uncertain.

The cumulative impact of these air 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. 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. In addition, Keystone already has SCR and Flue-gas desulfurization (FGD) controls in place.

On January 15, 2013, EPA issued a final rule for NSPS and National Emissions Standards for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE NESHAP/NSPS). The final rule allows diesel backup generators to operate for up to 100 hours annually under certain emergency circumstances without meeting emissions limitations, but requires units that operate over 15 hours to burn low sulfur fuel and report key engine information. The final rule eliminates after May 2014 the 50 hour exemption for peak shaving and other non-emergency demand response that was included in the proposed rule and, therefore, is not expected to result in additional megawatts of demand response to be bid into the PJM capacity auction.

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. The U.S. EPA is addressing the issue of carbon dioxide (CO2) emissions regulation for new and existing electric generating units through the New Source Performance Standards (NSPS) under Section 111 of the Clean Air Act. Pursuant to President

Obama s June 25, 2013 memorandum to U.S. EPA, the Agency re-proposed a Section 111(b) regulation for new units in September 2013 that may result in material costs of compliance for CO2 emissions for new fossil-fuel electric generating units, particularly coal-fired units. Under the President s memorandum, the U.S. EPA is also required to propose a Section 111(d) rule no later than June 1, 2014 to establish CO2 emission regulations for existing stationary sources. Pursuant to the President s Climate Action Plan, the U.S. EPA re-proposed regulations for the GHG emissions from new fossil fueled power plants on September 20, 2013. The U.S. EPA is also expected to propose by June 2014 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act, and to issue final regulations by June 2015. While the nature and impact of the final regulations is not yet known, to the extent that the rule results in emission reductions from fossil fuel fired plants, imposing some form of direct or indirect price of carbon in competitive electricity markets, Exelon s overall low-carbon generation portfolio results would benefit.

Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions.

Water Quality. 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. On March 28, 2011, the U.S. EPA issued a proposed rule, and is required under a Settlement Agreement to issue a final rule by November 4, 2013; on October 30, 2013 the U.S. EPA invoked the *force majeure* provision of the Settlement Agreement to extend the final rule deadline until November 20, 2013 due to the early October 2013 federal government shutdown. The U.S. EPA and the plaintiffs have stated that the deadline will be extended again for a brief period, but have not yet agreed on a date. 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 will require closed-cycle cooling. The economic viability of Generation s 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.

Hazardous and Solid Waste. Under proposed U.S. EPA rules issued on June 21, 2010, coal combustion residuals (CCR) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCR either as a hazardous or non-hazardous waste, under RCRA. 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 s plants that would be affected by the proposed rules are Keystone and Conemaugh in Pennsylvania, which have on-site landfills that meet the requirements of Pennsylvania solid waste regulations for non-hazardous waste disposal. However, until the final rule is adopted, the impact on these facilities is unknown. The U.S. EPA has entered into a Consent Decree which requires that a final rule be issued by December 19, 2014.

See Note 22 of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Regulatory and Legislative Actions

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.

In July 2011, an NRC Task Force formed in the aftermath of the Fukushima Daiichi events 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 NRC staff and the Task Force concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. 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.

In 2012, the NRC authorized its staff to issue three immediately effective orders (Tier 1 orders) to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. In addition, in 2012, the NRC staff recommended to the NRC the installation of engineered containment filtered venting systems for boiling-water reactors (BWR) with Mark I and Mark II containment structures. In summary, through the initial and/or subsequent orders and the NRC approved implementation guidance, the Tier 1 orders currently: (1) require licensees to provide sufficient onsite portable equipment and resources to maintain or restore cooling capabilities for the core and spent fuel pool and to maintain containment integrity until offsite equipment is available and have offsite equipment and resources available to sustain cooling functions indefinitely; (2) provide requirements for vents for BWR s with Mark I and Mark II containments to remain functional during severe accident conditions including the ability to vent the containment following core damage; and (3) require licensees to install instrumentation to provide a reliable indication of water level in the spent fuel pool. Finally, the NRC has directed the NRC staff to produce a technical evaluation to support rulemaking that considers filtering and performance-based strategies as options for BWR s with Mark I and Mark II containments. The NRC staff must then develop a final rule by March 2017.

Additionally, in 2012, the NRC had issued a detailed information request to every operating commercial nuclear power plant in the United States. The information requested requires: (1) use of the current NRC guidance to reevaluate current seismic and flood risk hazards against the design basis and provide a plan of actions to address vulnerabilities, including risks exceeding the design basis; (2) performance of walk downs to ensure the ability to respond to seismic and external flooding events and provide a corrective action plan to the NRC to address deficiencies; and (3) assessment of the means to provide power for communications equipment during a severe natural event and identify staffing required to implement the emergency plan for an event affecting all units with an extended loss of alternating current power and impeded access to the site. The nuclear industry proposed, and the NRC approved, an augmented approach to the seismic hazard analysis to accommodate industry wide availability of qualified technical resources needed to perform the required analysis. The NRC approved this augmented approach.

Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the NRC staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for the period from 2014 through 2018 is expected to be between approximately $350 million and $375 million of capital and $50 million of operating expense, as previously anticipated in Generation s planning projections. As Generation completes the design and installation planning for its actions, Generation will update these estimates. Further, Generation estimates incremental costs of $15 to $20 million per unit at eleven Mark I and II units for the installation of filtered vents, if ultimately required by the NRC. Generation s current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors, for further discussion of the risk factors.

Financial Reform Legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted in July 2010. While the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing, exchange trading, margin requirements, and other transparency requirements. The Dodd-Frank Act, however, also preserves the ability of end users in the energy industry to hedge their risks. In April 2012, the CFTC issued its rule defining swap dealers and major swap participants. Exelon has determined that it will conduct its commercial business in a manner that does not require registration as a swap dealer or major swap participant. Notwithstanding, there are additional rulemakings that have not yet been issued, including the capital and margin rules, which will further define the scope of the regulations and provide clarity as to the impact on the Registrants business, as well as to potential new opportunities. Depending on these final rules, the Registrants could be subject to significant new obligations.

The proposed regulations addressing collateral and capital requirements and exchange margin cash postings, when final, could require Generation to increase collateral requirements or cash postings in lieu of letters of credit currently issued to collateralize Swaps. Exelon had previously estimated that it could be required to make up to $1 billion of additional collateral postings under its bilateral credit lines. Given the swap dealer and the major swap participant definitions will not apply to Generation, the actual amount of collateral postings that will be required may be lower than Exelon s previous expectations due to the following factors: (a) the majority of Generation s physical wholesale portfolio does not meet the final CFTC Swap definition; (b) there will be minimal incremental costs associated with Generation s positions that are currently cleared and subject to exchange margin; and (c) Generation will not be a swap dealer or major swap participant and proposed capital requirements applicable to these entities will not apply to Generation.

The actual level of collateral required will depend on many factors, including but not limited to market conditions, the outcome of final margin rules for Swaps, the extent of its trading activity in Swaps, and Generation s credit ratings. Nonetheless, Generation has adequate credit facilities and flexibility in its hedging program to meet its anticipated collateral requirements estimated based on conservative assumptions.

In addition, the new regulations will impose new and ongoing compliance and infrastructure costs on Generation, which may amount to several million dollars per year.

Exelon and Generation continue to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on their results of operations, cash flows or financial position.

ComEd, PECO and BGE could also be subject to various Dodd-Frank Act requirements to the extent they enter into Swap transactions. However, at this time, management of ComEd, PECO and BGE do not expect to be materially affected by this legislation.

Energy Infrastructure Modernization Act. Since 2011, ComEd s distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois electric utility infrastructure. Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd s best estimate of the revenue requirement expected to be approved by the ICC for that year s reconciliation.

Formula Rate Tariff

In March 2013, the Illinois legislature passed Senate Bill 9 to clarify the intent of EIMA on the three issues decided in the Rehearing Order: an allowed return on ComEd s pension asset; the use of year-end rather than average rate base and capital structure in the annual reconciliation; and the use of ComEd s weighted average cost of capital interest rate rather than a short-term debt rate to apply to the annual reconciliation. On May 22, 2013, Senate Bill 9 became effective after the Illinois legislature overrode the Governor s veto of that Bill. On June 5, 2013, the ICC approved ComEd s updated distribution formula rate structure to reflect the impacts of Senate Bill 9.

In October 2013, the ICC opened an investigation (the Investigation), in response to a complaint filed by the Illinois Attorney General, to change the formula rate structure by requesting three changes: the elimination of the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance, the netting of associated accumulated deferred income taxes against the annual reconciliation balance in calculating interest, and the use of average rather than year-end rate base for determining any ROE collar adjustment. On November 26, 2013, the ICC issued its final order in the Investigation, rejecting two of the proposed changes but accepting the proposed change to eliminate the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance. The accepted change became effective in January 2014, and is estimated to reduce ComEd s 2014 revenue by approximately $8 million. ComEd and intervenors requested rehearing, however all rehearing requests were denied by the ICC. ComEd and intervenors have filed appeals with the Illinois Appellate Court. ComEd cannot predict the results of any such appeals. See 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Annual Reconciliation

On May 30, 2013, ComEd updated its revenue requirement allowed in the December 2012 Order to reflect the impacts of Senate Bill 9, which resulted in a reduction to the current revenue requirement in effect of $14 million. The rates took effect in July 2013.

2013 Filing. On April 29, 2013, ComEd filed its annual distribution formula rate, which was updated on May 30, 2013 to reflect the impacts of Senate Bill 9. The ICC s final order, issued on December 19, 2013, increased the revenue requirement by $341 million, reflecting an increase of $160 million for the initial revenue requirement for 2013 and an increase of $181 million for the annual reconciliation for 2012. The rate increase was set using an allowed return on capital of 6.94% (inclusive of an allowed return on common equity of 8.72%). The rates took effect in January 2014. ComEd requested a rehearing on specific issues, which was denied by the ICC. ComEd and intervenors also filed appeals. ComEd cannot predict the results of any such appeals. See 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

FERC Ameren Order. In July 2012, FERC issued an order to Ameren Corporation (Ameren) finding that Ameren had improperly included acquisition premiums/ goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make

refunds for the implied increase in rates in prior years. Ameren has filed for rehearing regarding the July 2012 FERC order. ComEd believes that the FERC order authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/ goodwill from its transmission formula rate, the impact could be material to ComEd s results of operations and cash flows.

FERC Order No. 1000 Compliance (ComEd, PECO and BGE). In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods applicable to certain new regional and interregional transmission projects. As part of the changes to the transmission planning procedures, the FERC required removal from all FERC-approved tariffs and agreements a right of first refusal to build certain new transmission facilities. In compliance with the regional transmission planning requirements of Order No. 1000, PJM as the transmission provider submitted a compliance filing to FERC on October 25, 2012. On the same day, certain of the PJM transmission owners including ComEd, PECO and BGE (collectively, the PJM Transmission Owners) submitted a filing asserting that their contractual rights embodied in the PJM governing documents continue to justify their right of first refusal to construct new reliability (and related) transmission projects and that the FERC should not be allowed to override such rights absent a showing that it is in the public interest to do so under the FERC s *Mobile-Sierra* standard of review. This is a heightened standard of review which the PJM Transmission Owners argued could not be satisfied based on the facts applicable to them. On March 22, 2013, FERC issued an order on the PJM Compliance Filing and the filing of these PJM Transmission Owners (1) rejecting the arguments of such PJM Transmission Owners that the PJM governing documents were entitled to review under the *Mobile-Sierra* standard, (2) accepting most of the PJM filing, removing the right-of-first refusal from the PJM tariffs; and (3) directing PJM to remove certain exceptions that it included in its compliance filing that FERC found did not comply with Order No. 1000. FERC s order could enable third parties to seek to build certain regional transmission projects that had previously been reserved for the PJM Transmission Owners, potentially reducing ComEd s, PECO s and BGE s financial return on new investments in energy transmission facilities. Numerous parties sought rehearing of the FERC s March 22, 2013 order, including the PJM Transmission Owners who sought rehearing of the FERC s rejection of their Mobile-Sierra and related arguments. The compliance filing was made on July 22, 2013. On January 16, 2014, FERC issued an order stating that PJM s filing while subject to further orders, is effective as of January 1, 2014.

FERC Transmission Complaint. On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. As of December 31, 2013, BGE cannot predict the likelihood or a reasonable estimate of the amount of a change, if any, in the allowed base return on equity, or a reasonable estimate of the refund period start date. While BGE cannot predict the outcome of this matter, if FERC orders a reduction of BGE s base return on equity to 8.7%, the annual impact would be a reduction in revenues of approximately $10 million. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

The Maryland Strategic Infrastructure Development and Enhancement Program. In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. Under the new law, following a proceeding before the MDPSC and with the MDPSC s approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. The new surcharge rates are expected to take effect in the first quarter of 2014. BGE cannot predict the outcome of this proceeding or how much of the requested plan and related surcharge the MDPSC will approve. The MDPSC held evidentiary hearings on BGE s proposed plan and surcharge on November 12, 2013 through November 14, 2013. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE s plan and surcharge. BGE must submit a list detailing specific projects planned for 2014 to the MDPSC for approval within 30 days of the decision. Upon approval of the project list by the MDPSC, BGE will be able to implement the surcharge rates on gas customers bills. The new surcharges are expected to take effect in the second quarter of 2014. In addition, BGE will be subject to an annual independent audit to review plan performance and progress. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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 accounting policies described below require significant judgment in their application, or 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 (Exelon and Generation)

Generation s ARO associated with decommissioning its nuclear units was $4.9 billion at December 31, 2013. The authoritative guidance requires that Generation estimate its obligation for the future decommissioning of its nuclear generating plants. To estimate that liability, Generation uses an internally-developed, probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios. 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, based upon the methodologies and significant estimates and assumptions described as follows:

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 Factors. 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 are assigned to alternative decommissioning approaches which 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 assumed would begin in 2025 in 2013 and 2012. The SNF acceptance date was based on management s estimates of the amount of time required for the DOE to select a site location and develop the necessary infrastructure. For more information regarding the estimated date that DOE will begin accepting SNF, see Note 22 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. The current NRC license for Oyster Creek expires in 2029. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. As a result of this decision the expected economic life of Oyster Creek was reduced by 10 years to correspond to Exelon s current best estimate as to the timing of ceasing generation operations at the Oyster Creek unit in 2019. 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 have 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 $210 million per unit as of December 31, 2013. 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. The accounting guidance required Generation to establish an ARO at fair value at the time of the initial adoption of the current accounting standard. Subsequent to the initial adoption, the ARO is adjusted for changes to estimated costs, timing of future cash flows and modifications to decommissioning assumptions, as described above.

Under the current accounting framework, the ARO is not required or permitted to be re-measured for changes in the CARFR that occur in isolation. This differs from the accounting requirements for other long-dated obligations, such as pension and other post-employment benefits that are required to be re-measured as and when corresponding discount rates change. If Generation s future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFRs, the obligation would increase from approximately $4.9 billion to approximately $5.5 billion. The ultimate decommissioning obligation will be funded by the NDTs. The NDTs are recorded on Exelon s and Generation s Consolidated Balance Sheets at December 31, 2013 at fair value of approximately $8.1 billion and have an estimated targeted annual pre-tax return of 5.9 % to 6.7 %.

To illustrate the significant impact that changes in the CARFR, when combined with changes in projected amounts and expected timing of cash flows, can have on the valuation of the ARO: i) had

Generation used the 2012 CARFRs rather than the 2013 CARFRs in performing its third quarter 2013 ARO update, Generation would have reduced the ARO by approximately $10 million as compared to the actual decrease to the ARO of $140 million; and ii) if the CARFR used in performing the third quarter 2013 ARO update (which also reflected increases in the amounts and changes to the timing of projected cash flows) was increased or decreased by 100 basis points, the ARO would have decreased by $300 million and increased $40 million, respectively, as compared to the actual decrease of $140 million.

ARO Sensitivities. Changes in the assumptions underlying the foregoing items could materially affect the decommissioning obligation. The impact to the ARO of a change in any one of these assumptions is highly dependent on how the other assumptions will change as well. As an example, Exelon had a historical increase of approximately $670 million in the value of the ARO which was driven by Generation modifying the assumed timing of the DOE acceptance of SNF for disposal from 2020 to 2025. The modification of the assumed DOE acceptance date affected the calculation of the ARO in isolation as follows; i) the change in the timing of DOE acceptance of SNF increased the total number of years in which decommissioning activities are estimated to occur, by five years on average, thereby increasing the total expected nominal cash flows required to decommission the units; ii) the nominal cash flows were subjected to additional escalation as a result of the extension of the decommissioning period increasing the total estimated costs required to decommission the units; and iii) the escalated cash flows were discounted at the then current CARFRs which had dramatically decreased during that time period.

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 (Decrease) to ARO at December 31, 2013**
Cost escalation studies		
Uniform increase in escalation rates of 25 basis points	$	560
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	$	190
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	$	290
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	$	430
Extend the estimated date for DOE acceptance of SNF to 2030	$	50
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with an increase in discount rates of 100 basis points	$	(230)
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with a decrease in discount rates of 100 basis points	$	600

For more information regarding accounting for nuclear decommissioning obligations, see Notes 1 and 15 of the Combined Notes to Consolidated Financial Statements.

Goodwill (Exelon and ComEd)

As of December 31, 2013, Exelon s and ComEd s carrying amount of goodwill was approximately $2.6 billion, 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 possible impairment of its goodwill at least annually or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the ComEd reporting unit

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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. Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, entities should assess, among other things, macroeconomic conditions, industry and market considerations, overall financial performance, cost factors, and entity-specific events. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value-based test is performed. 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 accounting 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, projected operating and capital cash flows for ComEd s business and the fair value of debt. In applying the second step (if needed), management must estimate the fair value of specific assets and liabilities of the reporting unit.

Management concluded the remeasurement of the like-kind exchange position and the charge to ComEd s earnings in the first quarter of 2013 triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of January 31, 2013. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

ComEd performed a quantitative assessment as of November 1, 2013, for its 2013 annual goodwill impairment assessment. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

While neither the interim nor the annual assessments indicated an impairment of ComEd s goodwill, certain assumptions used to estimate the fair value of ComEd are highly sensitive to changes. Adverse regulatory actions, such as early termination of EIMA, or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd s business, and the fair value of debt, could potentially result in a future impairment of ComEd s goodwill, which could be material. Based on the results of the annual goodwill test performed as of November 1, 2013, the estimated fair value of ComEd would have needed to decrease by more than 10% for ComEd to fail the first step of the impairment test. See Note 1 Significant Accounting Policies, Note 10 Intangible Assets and Note 14 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting (Exelon and Generation)

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 requires management s judgment, the utilization of independent valuation experts and involves the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. 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 4 Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

Unamortized Energy Assets and Liabilities (Exelon and Generation)

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired. The initial amount recorded represents the fair value of the contract at the time of acquisition, and the balance is amortized over the life of the contract in relation to the present value of the underlying cash flows. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues. Refer to Note 4 Mergers and Acquisitions and Note 10 Intangible Assets for further discussion.

Impairment of Long-lived Assets (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE regularly monitor and evaluate their long-lived assets and asset groups, 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 prices 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, among others.

The review of long-lived assets and asset groups 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 recoverability of an asset or asset group 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 or asset groups 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 and associated intangible contract assets recorded on the balance sheet. The cash flows from the generation units are generally evaluated at a regional portfolio level with cash flows generated from Generation s customer supply and risk management activities, including cash flows from contracts that are accounted for as intangible contract assets and liabilities recorded on the balance sheet. In certain cases generation assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generation assets (typically contracted renewables).

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. The fair value of the long-lived asset or asset group is dependent upon a market participant s view of the exit price of the assets. This includes significant assumptions of the estimated future cash flows generated by the assets and market discount rates. 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. 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 that include significant unobservable inputs (Level 3) such as revenue and generation forecasts, projected capital, and maintenance expenditures and discount rates, as well as information from various public, financial and industry sources. An impairment determination would require the affected Registrant to reduce either the long-lived asset or asset group, including any intangible contract assets and liabilities, and current period earnings by the amount of the impairment.

Generation evaluates unproved gas producing properties at least annually to determine if they are impaired. Impairment for unproved gas property occurs if there are no firm plans to continue drilling, lease expiration is at risk, or historical experience indicates a decline in carrying value below fair value.

Exelon holds investments in coal-fired plants in Georgia and Texas subject to long-term leases. The investments are accounted for as direct financing lease investments. The investments represent the estimated residual values of the leased assets at the end of the respective lease terms. On an annual basis, Exelon reviews the estimated residual values of its direct financing lease investments and records an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments using a discounted cash flow analysis, which takes into consideration the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates.

Generation also evaluates its equity method investments to determine whether or not they are impaired based on whether the investment has experienced a decline in value that is not temporary in nature. Additionally, if one of Generation s equity method investments recognize an impairment, Generation would record its proportionate share of that impairment loss through its equity earnings (losses) of unconsolidated affiliates. Generation would also evaluate the investment for a decline in value at that time that is not temporary in nature.

See Note 8 of the Combined Notes to Consolidated Financial Statements for a discussion of asset impairment evaluations made by Exelon.

Depreciable Lives of Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

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

The estimated service lives of the nuclear generating facilities are based on the estimated useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses for all of Generation s operating nuclear generating stations except for Oyster Creek. 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 evaluates annually the estimated service lives of its generating facilities based on feasibility assessments as well as economic and capital requirements. The estimated service lives of hydroelectric facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the Conowingo and Muddy Run 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. Constellation completed a depreciation rate study during the fourth quarter of 2010, which resulted in the implementation of new depreciation rates effective during the fourth quarter of 2010.

ComEd is required to file a depreciation rate study at least every five years with the ICC. ComEd completed a depreciation study in 2014 and filed the updated depreciation rates with both FERC and the ICC in January 2014. This is expected to result in the implementation of new depreciation rates effective first quarter 2014.

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, 2010 for electric transmission assets and January 1, 2011 for electric distribution and gas assets.

The MDPSC does not mandate the frequency or timing of BGE s depreciation studies. In December 2006, BGE filed revised depreciation rates with the MDPSC for both its electric distribution and gas assets. Revisions to depreciation rates from this filing were finalized July 1, 2010.

Defined Benefit Pension and Other Postretirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for substantially all Generation, ComEd, PECO, BGE and BSC employees. See Note 16 Retirement Benefits 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 affected 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 participant 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 others. The assumptions are updated annually and upon any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. 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 16 Retirement Benefits 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 7.50%, 7.50%, and 8.00% for 2013, 2012 and 2011, respectively. The weighted average expected return on assets assumption used in calculating other postretirement benefit costs was 6.45%, 6.68%, and 7.08% in 2013, 2012 and 2011, 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. See Note 16 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon s asset allocations. Exelon used an EROA of 7.00% and 6.59% to estimate its 2014 pension and other postretirement benefit costs, respectively.

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

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and other postretirement benefit plans. The actual asset returns across the Registrants pension and other postretirement benefit plans for the year ended December 31, 2013 were 6.73% and 11.41%, respectively, compared to an expected long-term return assumption of 7.50% and 6.45%, respectively.

Discount Rate. The discount rates used to determine the pension and other postretirement benefit obligations were 4.80% and 4.90%, respectively, at December 31, 2013. The discount rates at December 31, 2013 represent weighted-average rates for both pension and other postretirement benefit plans. At December 31, 2013 and 2012, 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 4.80% and 4.90% to estimate its 2014 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, the Registrants were 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 changed the manner in which it will receive prescription drug subsidies beginning 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. Effective in 2002, Constellation amended its other postretirement benefit plans for all subsidiaries other than Nine Mile Point by capping retiree medical coverage for future retirees who were under the age of 55 on January 1, 2002 at 2002 levels. Therefore, the excise tax is not expected to have a material impact on the legacy Constellation other postretirement benefit plans. However, certain key assumptions are required to estimate the impact of the excise tax on the other postretirement obligation for legacy Exelon plans, 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% for 2013, 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 2013 cost:				
Discount rate [(a)]	0.5%	$ (63)	$ (34)	$ (97)
	(0.5%)	68	48	116
EROA	0.5%	(68)	(10)	(78)
	(0.5%)	68	10	78
Health care cost trend rate	1.00%	N/A	90	90
	(1.00%)	N/A	(62)	(62)
Change in benefit obligation at December 31, 2013:				
Discount rate [(a)]	0.5%	(904)	(297)	(1,201)
	(0.5%)	965	318	1,283
Health care cost trend rate	1.00%	N/A	858	858
	(1.00%)	N/A	(607)	(607)

(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 11.8 years, 11.9 years, and 12.1 years for the years ended December 31, 2013, 2012 and 2011, respectively.

For other postretirement benefits, Exelon amortizes its unrecognized 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 8.7 years, 8.9 years and 6.6 years for the years ended December 31, 2013, 2012 and 2011, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 9.8 years, 10.1 years and 8.7 years for the years ended December 31, 2013, 2012 and 2011, respectively.

Regulatory Accounting (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE 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, PECO and BGE 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, 2013, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE 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, PECO and BGE 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 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon, ComEd, PECO and BGE.

For each regulatory jurisdiction in which they conduct business, Exelon, ComEd, PECO and BGE 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 recent rate orders, historical regulatory treatment for similar costs in ComEd s, PECO s and BGE s jurisdictions, and factors such as changes in applicable regulatory and political environments. Furthermore, Exelon, ComEd, PECO and BGE 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, if any, to which 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 tariffs for ComEd and BGE. 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, PECO s and BGE 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, PECO and BGE are ultimately different than actual regulatory outcomes, the impact on their results of operations, financial position, and cash flows could be material.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Accounting for Derivative Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants utilize derivative instruments to manage their exposure to fluctuations in interest rates, changes in interest rates related to planned future debt issuances and changes in the fair value of outstanding debt. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases and other energy-related products marketed and purchased. Additionally, Generation enters into energy-related derivatives for proprietary trading purposes. ComEd has entered into contracts to procure energy, capacity and ancillary services. In addition, ComEd had a financial swap contract with Generation that expired May 31, 2013 and currently holds floating-to-fixed energy swaps with several unaffiliated suppliers that extend into 2032. PECO and BGE have entered into derivative natural gas contracts to hedge their 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. BGE has also entered into derivative contracts to procure electric supply through a competitive auction process as outlined in its MDPSC-approved SOS Program. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes. The Registrants derivative activities are in accordance with Exelon s Risk Management Policy (RMP). See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants derivative instruments.

The Registrants account for derivative financial instruments under the applicable authoritative guidance. Determining whether or not a contract qualifies as a derivative under this guidance requires that management exercise significant judgment, including assessing the market liquidity as well as determining whether a contract has one or more underlyings and one or more notional amounts. Further, interpretive guidance related to the authoritative literature continues to evolve, including how it applies to energy and energy-related products. Changes in management s assessment of contracts and the liquidity of their markets, and changes in authoritative guidance related to derivatives, could result in previously excluded contracts being subject to the provisions of the authoritative derivative guidance. Generation has determined that contracts to purchase uranium, contracts to purchase and sell capacity in certain ISO s, certain emission products and 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, certain capacity, emission nor the REC markets are sufficiently liquid to conclude that physical forward contracts are readily convertible to cash. If these markets do become sufficiently liquid in the future and Generation would be required to account for these 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 mark-to-market gains or losses, which may have a significant 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, except for certain derivatives that qualify for, and are elected under, the 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 commodity transactions, effective with the date of merger with Constellation, Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation s designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all economic hedges for commodities are recorded at fair value through earnings for the combined company. In addition, for energy-related derivatives entered into for proprietary trading purposes, changes in the fair value of the derivatives are recognized in earnings each period. For economic hedges that are not designated for hedge accounting for ComEd, PECO and BGE, changes in the fair value each period are recorded as a regulatory asset or liability.

Normal Purchases and Normal Sales Exception. 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 some of these contracts are considered derivative financial instruments under the authoritative guidance, certain of these qualifying 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. 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 is not financially settled on a net basis. The contracts that ComEd has entered into with suppliers as part of ComEd s energy procurement process, PECO s full requirement contracts and block contracts under the PAPUC-approved DSP program, most of PECO s natural gas supply agreements and all of BGE s full requirement contracts and natural gas supply agreements that are derivatives qualify for the normal purchases and normal sales exception.

Commodity Contracts. Identification of a commodity contract as an economic hedge requires Generation to determine that the contract is in accordance with the RMP. Generation reassesses its economic hedges on a regular basis to determine if they continue to be within the guidelines of the RMP.

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

Interest Rate and Foreign Exchange Derivative Instruments. The Registrants may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve the targeted level of variable-rate debt as a percent of total debt. Additionally, the Registrants may use forward-starting interest rate swaps and treasury rate locks to lock in interest-rate levels in anticipation of future financings and floating to fixed swaps for project financing. In addition, Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the economic hedge and proprietary trading activity is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or change in market interest rates. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. The fair value of the 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 and foreign exchange curves. As these inputs are based on observable data and valuations of similar instruments, the interest rate and foreign exchange derivatives are primarily categorized in Level 2 in the fair value hierarchy. Certain exchange based interest rate derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Notes 11 and 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants derivative instruments.

Taxation (Exelon, Generation, ComEd, PECO and BGE)

Significant management judgment is required in determining the Registrants provisions for income taxes, primarily due to the uncertainty related to tax positions taken, as well as deferred tax assets and liabilities and valuation allowances. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition 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 Registrants consolidated financial statements.

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

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, the Registrants forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. While the Registrants believe the resulting tax balances as of December 31, 2013 and 2012 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 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

Accounting for Loss Contingencies (Exelon, Generation, ComEd, PECO and BGE)

In the preparation of their financial statements, the Registrants make 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 the Registrants make 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 their consolidated financial statements.

Environmental Costs. Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work, changes in technology, regulations and the requirements of local governmental authorities. Periodic studies are conducted at ComEd, PECO and BGE to determine future remediation requirements and estimates are adjusted accordingly. In addition, periodic reviews are performed at Generation to assess the adequacy of its environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant effect on the Registrants results of operations, financial position and cash flows. See Note 22 of the Combined Notes to Consolidated Financial Statements for further information.

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

Revenue Recognition (Exelon, Generation, ComEd, PECO and BGE)

Sources of Revenue and Selection of Accounting Treatment. The Registrants earn revenues from various business activities including: the sale of energy and energy-related products, such as natural gas, capacity, and other commodities in non-regulated markets (wholesale and retail)*;* the sale and delivery of electricity and natural gas in regulated markets; and the provision of other energy-related non-regulated products and services.

The appropriate accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable accounting standards. The Registrants primarily use accrual and mark-to-market accounting as discussed in more detail below.

Accrual Accounting. Under accrual accounting, the Registrants record revenues in the period when services are rendered or energy is delivered to customers. The Registrants generally use accrual accounting to recognize revenues for sales of electricity, natural gas, and other commodities as part of their physical delivery activities. The Registrants enter into these sales transactions using a variety of instruments, including non-derivative agreements, derivatives that qualify for and are designated as normal purchases and normal sales (NPNS) of commodities that will be physically delivered, sales to utility customers under regulated service tariffs, and spot-market sales, including settlements with independent system operators.

Mark-to-Market Accounting. The Registrants record revenues using the mark-to-market method of accounting for transactions that meet the definition of a derivative for which they are not permitted, or have not elected, the NPNS exception. These mark-to-market transactions primarily relate to risk management activities and economic hedges of other accrual activities. Mark-to-market revenues include: inception gains or losses on new transactions where the fair value is observable and realized; and unrealized gains and losses from changes in the fair value of open contracts.

Use of Estimates. 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. The estimated reconciliations can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

Unbilled Revenues. The determination of Generation s, ComEd s, PECO s and BGE s retail energy sales to individual customers 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 or decreases in volumes delivered to the utilities customers and favorable or unfavorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. In addition, volumes may fluctuate monthly as a result of customers electing to use an alternate supplier, which could be

significant to the calculation of unbilled revenue since unbilled commodity receivables are not recorded for these customers. 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.

See Note 6 of the Combined Notes to Consolidated Financial Statements for additional information.

***Regulated Transmission & Distribution Revenues*.** ComEd s EIMA distribution formula rate tariff provides for annual reconciliations to the distribution revenue requirement. As of the balance sheet dates, ComEd has recorded its best estimates of the distribution revenue impact resulting from changes in rates that ComEd believes are probable of approval by the ICC in accordance with the formula rate mechanism. 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. The estimated reconciliation can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

ComEd s and BGE s FERC transmission formula rate tariffs provide for annual reconciliations to the transmission revenue requirements. As of the balance sheet dates, ComEd and BGE have recorded the best estimate of their respective transmission revenue impact resulting from changes in rates that ComEd and BGE believe are probable of approval by FERC in accordance with the formula rate mechanism. 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. The estimated reconciliation can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

Allowance for Uncollectible Accounts (Exelon, Generation, ComEd, PECO and BGE)

The allowance for uncollectible accounts reflects the Registrants best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company 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. BGE estimates the allowance for uncollectible accounts on customer receivables by assigning reserve factors for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. ComEd, PECO and BGE 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, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd s, PECO s and BGE s provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 6 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, 2013, 2012 and 2011 set forth below include intercompany transactions, which are eliminated in Exelon s consolidated financial statements.

Net Income (Loss) on Common Stock by Business Segment

	2013	2012 [(a)]	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Exelon	$ 1,719	$ 1,160	$ 559	$ 2,495	$ (1,335)
Generation	1,070	562	508	1,771	(1,209)
ComEd	249	379	(130)	416	(37)
PECO	388	377	11	385	(8)
BGE	197	(9)	206	123	(132)

(a) For BGE, reflects BGE s operations for the year ended December 31, 2012. For Exelon and Generation, includes the operations of the Constellation and BGE from the date of the merger, March 12, 2012, through December 31, 2012.

Results of Operations Generation

	2013	2012 [(b)]	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Operating revenues	$ 15,630	$ 14,437	$ 1,193	$ 10,447	$ 3,990
Purchased power and fuel expense	8,197	7,061	(1,136)	3,589	(3,472)
Revenue net of purchased power and fuel expense [(a)]	7,433	7,376	57	6,858	518
Other operating expenses					
Operating and maintenance	4,534	5,028	494	3,148	(1,880)
Depreciation and amortization	856	768	(88)	570	(198)
Taxes other than income	389	369	(20)	264	(105)
Total other operating expenses	5,779	6,165	386	3,982	(2,183)
Equity in earnings (losses) of unconsolidated affiliates	10	(91)	101	(1)	(90)
Operating income	1,664	1,120	544	2,875	(1,755)
Other income and (deductions)					
Interest expense	(357)	(301)	(56)	(170)	(131)
Other, net	368	239	129	122	117
Total other income and (deductions)	11	(62)	73	(48)	(14)
Income before income taxes	1,675	1,058	617	2,827	(1,769)
Income taxes	615	500	(115)	1,056	556

Net income	1,060	558	502	1,771	(1,213)
Net loss attributable to non-controlling interest	(10)	(4)	(6)		4
Net income attributable to membership interest	$ 1,070	$ 562	$ 508	$ 1,771	$ (1,209)

(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.

(b) Includes the operations of Constellation from the date of the merger, March 12, 2012, through December 31, 2012.

Net Income Attributable to Membership Interest

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Generation s net income attributable to membership interest increased compared to the same period in 2012 primarily due to higher revenues, net of purchased power and fuel expense, lower operating and maintenance expense and higher earnings from Generation s interest in CENG; partially offset by impairment of certain generating assets, higher depreciation expense, higher property taxes, and higher interest expense. The increase in revenues, net or purchased power and fuel expense was primarily due to increased capacity prices and higher nuclear volume partially offset by lower realized energy prices, higher nuclear fuel costs, and lower mark-to-market gains in 2013. The decrease in operating and maintenance expense was largely due to 2012 costs associated with a settlement with FERC in 2012 and decreases in transaction costs and employee-related costs associated with the merger.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Generation s net income attributable to membership interest decreased compared to the same period in 2012 primarily due to higher operating expenses, the loss on the sale of Brandon Shores, Wagner and C.P. Crane (collectively Maryland generating stations) and the amortization of acquired energy contracts recorded at fair value at the merger date; offset by higher revenues, net of purchased power and fuel expense and favorable NDT fund performance. The increase in operating expenses was due to the addition of Constellation s financial results from March 12, 2012, costs related to a 2012 settlement with FERC and transaction and employee-related severance costs associated with the merger. The increase in revenues, net of purchased power and fuel expense was also primarily due to the merger. See Note 4 for additional information regarding the loss on the sale of three Maryland generating stations.

Revenue Net of Purchased Power and Fuel Expense

Generation s six reportable segments are based on the geographic location of its assets, and are largely representative of the footprints of an ISO/RTO and/or NERC region. Descriptions of each of Generation s six reportable segments are as follows:

Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.

Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO s Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.

New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

New York represents operations within New York ISO, which covers the state of New York in its entirety.

ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.

Other Regions not considered individually significant:

South represents operations in the FRCC, MISO s Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of

Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation s South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.

West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.

Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, investments in natural gas exploration and production activities, proprietary trading, energy efficiency and demand response, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems. Further, the following activities are not allocated to a region, and are reported in Other: compensation under the reliability-must-run rate schedule; results of operations from the Maryland Clean-Coal assets sold in the fourth quarter of 2012; unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities and allocates resources using the measure of revenue net of purchased power and fuel expense which is a non-GAAP measurement. Generation s operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. 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.

For the year ended December 31, 2013 compared to 2012 and 2012 compared to 2011, Generation s revenue net of purchased power and fuel expense by region were as follows:

			2013 vs. 2012			2012 vs. 2011	
	2013	**2012 [a]**	**Variance**	**% Change**	**2011**	**Variance**	**% Change**
Mid-Atlantic [b][f]	$ 3,270	$ 3,433	$ (163)	(4.7)%	$ 3,350	$ 83	2.5%
Midwest [c]	2,586	2,998	(412)	(13.7)%	3,547	(549)	(15.5)%
New England	185	196	(11)	(5.6)%	9	187	n.m.
New York [f]	(4)	76	(80)	(105.3)%		76	n.m.
ERCOT	436	405	31	7.7%	84	321	n.m.
Other Regions [d]	201	131	70	53.4%	(14)	145	n.m.
Total electric revenue net of purchased power and fuel expense	$ 6,674	$ 7,239	$ (565)	(7.8)%	$ 6,976	$ 263	3.8%
Proprietary Trading	(8)	(14)	6	42.9%	24	(38)	n.m.
Mark-to-market gains (losses)	504	515	(11)	(2.1)%	(288)	803	n.m.
Other [e]	263	(364)	627	n.m.	146	(510)	n.m.
Total revenue net of purchased power and fuel expense	$ 7,433	$ 7,376	$ 57	0.8%	$ 6,858	$ 518	7.6%

(a) Includes results for Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.

(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.
(c) Results of transactions with ComEd are included in the Midwest region.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at merger date of $488 million and $1,098 million pre-tax for the twelve months ended December 31, 2013 and December 31, 2012, respectively.
(f) Includes $542 million and $450 million of purchased power from CENG in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2013. Includes $487 million and $306 million of purchased power from CENG in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2012. See Note 25 of the Combined Notes to Consolidated Financial Statements for additional information.

Generation s supply sources by region are summarized below:

			2013 vs. 2012			2012 vs. 2011	
Supply source (GWh)	**2013**	**2012 (a)**	**Variance**	**% Change**	**2011**	**Variance**	**% Change**
Nuclear generation (b)							
Mid-Atlantic	48,881	47,337	1,544	3.3%	47,287	50	0.1%
Midwest	93,245	92,525	720	0.8%	92,010	515	0.6%
	142,126	139,862	2,264	1.6%	139,297	565	0.4%
Fossil and renewables (b)							
Mid-Atlantic (b)(d)	11,714	8,808	2,906	33.0%	7,572	1,236	16.3%
Midwest	1,478	971	507	52.2%	596	375	62.9%
New England	10,896	9,965	931	9.3%	8	9,957	n.m.
ERCOT	6,453	6,182	271	4.4%	2,030	4,152	n.m.
Other Regions (e)	6,664	5,913	751	12.7%	1,432	4,481	n.m.
	37,205	31,839	5,366	16.9%	11,638	20,201	n.m.
Purchased power							
Mid-Atlantic (c)	14,092	20,830	(6,738)	(32.3)%	2,898	17,932	n.m.
Midwest	4,408	9,805	(5,397)	(55.0)%	5,970	3,835	64.2%
New England	7,655	9,273	(1,618)	(17.4)%		9,273	n.m.
New York (c)	13,642	11,457	2,185	19.1%		11,457	n.m.
ERCOT	15,063	23,302	(8,239)	(35.4)%	7,537	15,765	n.m.
Other Regions (e)	14,931	17,327	(2,396)	(13.8)%	2,503	14,824	n.m.
	69,791	91,994	(22,203)	(24.1)%	18,908	73,086	n.m.
Total supply by region (f)							
Mid-Atlantic (g)	74,687	76,975	(2,288)	(3.0)%	57,757	19,218	33.3%
Midwest (h)	99,131	103,301	(4,170)	(4.0)%	98,576	4,725	4.8%
New England	18,551	19,238	(687)	(3.6)%	8	19,230	n.m.
New York	13,642	11,457	2,185	19.1%		11,457	n.m.
ERCOT	21,516	29,484	(7,968)	(27.0)%	9,567	19,917	n.m.
Other Regions (e)	21,595	23,240	(1,645)	(7.1)%	3,935	19,305	n.m.
Total supply	249,122	263,695	(14,573)	(5.5)%	169,843	93,852	55.3%

(a) Includes results for the Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.
(b) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and does not include ownership through equity method investments (e.g., CENG).
(c) Purchased power includes physical volumes of 12,067 GWh and 9,925 GWh in the Mid-Atlantic and 12,165 GWh and 9,350 GWh in New York as a result of the PPA with CENG for the years ended December 31, 2013 and 2012 respectively.
(d)

Excludes generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger.

(e) Other Regions includes South, West and Canada, which are not considered individually significant.

(f) Excludes physical proprietary trading volumes of 8,762 GWh, 12,958 GWh and 5,742 GWh for the years ended December 31, 2013, 2012 and 2011 respectively.

(g) Includes sales to PECO through the competitive procurement process of 5,070 GWh, 7,762 GWh, and 7,041 GWh for the years ended December 31, 2013, 2012 and 2011 respectively. Sales to BGE of 5,595 GWh and 3,766 GWh were included for the years ended December 31, 2013 and 2012 respectively.

(h) Includes sales to ComEd under the RFP procurement of 7,491 GWh, 4,152 GWh and 4,731 GWh for the years ended December 31, 2013, 2012 and 2011 respectively.

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the year ended December 31, 2013 as compared to the same period in 2012 and 2012 as compared to the same period in 2011.

$/MWh	2013	2012 (a)	2013 vs. 2012 % Change	2011	2012 vs. 2011 % Change
Mid-Atlantic (b)	$ 43.78	$ 44.60	(1.8)%	$ 58.00	(23.1)%
Midwest (c)	26.09	29.02	(10.1)%	35.99	(19.4)%
New England	9.97	10.19	(2.1)%	n.m.	n.m.
New York	(0.29)	6.63	(104.4)%	n.m.	n.m.
ERCOT	20.26	13.74	47.5%	8.78	56.5%
Other Regions (d)	9.31	5.64	65.0%	(3.56)	n.m.
Electric revenue net of purchased power and fuel expense per MWh (e)(f)	$ 26.79	$ 27.45	(2.4)%	$ 41.07	(33.2)%

(a) Includes financial results for the Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.

(b) Includes sales to PECO of $405 million (5,070 GWh), $536 million (7,762 GWh) and $508 million (7,041 GWh) for the years ended December 31, 2013, 2012 and 2011, respectively. Sales to BGE of $455 million (5,595 GWh) and $322 million (3,766 GWh) were included for the years ended December 31, 2013 and 2012 respectively. Excludes compensation under the reliability-must-run rate schedule and the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the merger.

(c) Includes sales to ComEd of $283 million (7,491 GWh), $162 million (4,152 GWh) and $179 million (4,731 GWhs) and settlements of the ComEd swap of $230 million, $627 million and $474 million for years ended December 31, 2013, 2012 and 2011, respectively.

(d) Other Regions includes South, West and Canada, which are not considered individually significant.

(e) 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, 2013, 2012 and 2011, respectively, and excludes the mark-to-market impact of Generation s economic hedging activities.

(f) Excludes Generation s other business activities not allocated to a region, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency, energy management and demand response. Also excludes Generation s compensation under the reliability-must-run rate schedule, the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the Exelon and Constellation merger of $488 million and $1,098 million, respectively.

Mid-Atlantic

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic of $163 million was primarily due to lower realized power prices and increased nuclear fuel costs, partially offset by the addition of Constellation in 2012, higher capacity revenues, and higher nuclear revenues.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $83 million was primarily due to the addition of Constellation in 2012 and higher capacity revenues, partially offset by lower realized power prices and increased nuclear fuel costs.

Midwest

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in revenue net of purchased power and fuel expense in the Midwest of $412 million was primarily due to lower realized power prices, increased nuclear fuel costs, and lower capacity revenues, partially offset by higher nuclear revenues.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in revenue net of purchased power and fuel expense in the Midwest of $549 million was primarily due to lower capacity revenues, increased nuclear fuel costs, and lower realized power prices, partially offset by decreased congestion costs.

New England

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $11 million decrease in revenue net of purchased power and fuel expense in New England is primarily due to lower realized energy prices, partially offset by the addition of Constellation in 2012. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $187 million increase in revenue net of purchased power and fuel expense in New England was the result of the Constellation merger. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

New York

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $80 million decrease in revenue net of purchased power and fuel expense in New York was primarily due to decreased realized energy prices, partially offset by the addition of Constellation. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $76 million increase in revenue net of purchased power and fuel expense in New York was the result of the Constellation merger. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

ERCOT

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $31 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily due to increased realized energy prices and the addition of Constellation in 2012, partially offset by a decrease due to the termination of an energy supply contract with a retail power supply company that was previously a consolidated variable interest entity. As a result of the termination, Generation no longer has a variable interest in the retail supply company and ceased consolidation of the entity during the third quarter of 2013.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $321 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily as a result of the addition of Constellation in 2012, partially offset by a decrease in revenue net of purchased power and fuel expense in the legacy Generation ERCOT portfolio driven by the performance of Generation s generating units during extreme weather events that occurred in Texas in February and August 2011.

Other Regions

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $70 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the addition of Constellation in 2012, in addition to increased renewable generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $145 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the Constellation merger.

Mark-to-market

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were $504 million in 2013 compared to gains of $515 million in 2012. See Notes 11 and 12 of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were $515 million in 2012 compared to losses of $288 million in 2011. See Note 11 and 12 of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Other

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $627 million increase in other revenue net of purchased power and fuel was primarily due to reduced amortization expense of the acquired energy contracts recorded at fair value at the merger date. In addition, the increase is also attributable to results from activities acquired as part of the 2012 merger with Constellation including retail gas, energy efficiency, energy management and demand response, upstream natural gas, and the design and construction of renewable energy facilities. These increases were partially offset by the reduction in revenues net of purchased power and fuel expense from the sale of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $510 million decrease in other revenue net of purchased power and fuel was primarily due to increased amortization expense of the acquired energy contracts recorded at fair value at the merger date. This decrease was partially offset by results from activities acquired as part of the 2012 merger with Constellation including retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities. In addition, other revenue net of purchased power and fuel includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in fourth quarter of 2012 as a result of the Exelon and Constellation merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for 2013, as compared to 2012 and 2011, for the Generation-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.

	2013	2012	2011
Nuclear fleet capacity factor [a]	94.1%	92.7%	93.3%
Nuclear fleet production cost per MWh [a]	$ 19.83	$ 19.50	$ 18.86

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC, and CENG s nuclear facilities, which are operated by CENG. Reflects ownership percentage of stations operated by Exelon.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The nuclear fleet capacity factor, which excludes Salem, increased primarily due to a lower number of planned refueling outage days in 2013, partially offset by a higher number of non-refueling outage days. For 2013 and 2012, planned refueling outage days totaled 233 and 274, respectively, and non-refueling outage days totaled 75 and 73, respectively. Higher nuclear fuel costs and higher plant operating and maintenance costs, partially offset by higher number of net MWhs generated resulted in a higher production cost per MWh during 2013 as compared to 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The nuclear fleet capacity factor, which excludes Salem, decreased primarily due to a higher number of non-refueling outage days, partially offset by a lower number of planned refueling outage days in 2012. For 2012 and 2011, planned refueling outage days totaled 274 and 283, respectively, and non-refueling outage days totaled 73 and 52, respectively. Higher nuclear fuel costs resulted in a higher production cost per MWh during 2012 as compared to 2011.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2013 compared to 2012, consisted of the following:

	Increase (Decrease)
Plant retirements and divestitures [a]	$ (440)
FERC settlement [b]	(195)
Constellation merger and integration costs	(107)
Maryland commitments	(35)
Bodily injury costs [c]	(16)
Nuclear refueling outage costs, including the co-owned Salem plant [d]	(14)
Corporate allocations [e]	(5)
Labor, other benefits, contracting and materials [f]	160
Impairment and related charges of certain generating assets	160
Midwest generation bankruptcy charges	11
Pension and non-pension postretirement benefits expense	5
Other	(18)

Decrease in operating and maintenance expense	$	(494)

(a) Reflects the operating and maintenance expense associated with the generating assets retired or divested during 2012.
(b) Reflects costs incurred as part of a March 2012 settlement with the FERC to resolve a dispute related to Constellation s prior period hedging and risk management transactions.
(c) Reflects decreased asbestos-related bodily injury expense for 2013 compared to 2012.
(d) Reflects the impact of decreased planned refueling outage days during 2013.
(e) The decrease in cost allocations during 2013 primarily reflects merger synergy savings for Exelon s corporate operations and shared service entities, partially offset by the impact of an increased share of corporate allocated costs due to the merger.
(f) Includes cost of sales of our other business activities that are not allocated to a region.

The changes in operating and maintenance expense for 2012 compared to 2011, consisted of the following:

	Increase (Decrease)
Labor, other benefits, contracting and materials [a]	$ 845
Loss on the sale of Maryland Clean Coal assets [b]	278
FERC settlement [c]	195
Constellation merger and integration costs	182
Corporate allocations [d]	175
Pension and non-pension postretirement benefits expense	76
Maryland commitments [e]	35
Nuclear refueling outage costs, including the co-owned Salem plant [f]	(52)
Other	146
Increase in operating and maintenance expense	$ 1,880

(a) Includes cost of sales of our other business activities that are not allocated to a region.
(b) Represents expense recorded during the third quarter of 2012 due to the reduction in book value. Upon completion of the November 30, 2012 transaction, Generation recorded a $6 million gain within Other, net in its Consolidated Statements of Operations and Comprehensive Income. The net loss on the sale of the Maryland Clean Coal assets was $272 million. See 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(c) Reflects costs incurred as part of a March 2012 settlement with the FERC to resolve a dispute related to Constellation s prior period hedging and risk management transactions.
(d) Reflects an increased share of corporate allocated costs due to the merger.
(e) Reflects costs incurred as part of the Maryland order approving the merger.
(f) Reflects the impact of decreased planned refueling outages during 2012.

Depreciation and Amortization

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the addition of Constellation facilities and ongoing capital additions.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the addition of Constellation facilities; and capital additions and other upgrades to legacy plants.

Taxes Other Than Income

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase was primarily due to the addition of Constellation s financial results in 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase was primarily due to the addition of Constellation s financial results in 2012.

Equity in Earnings (Losses) of Unconsolidated Affiliates

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Equity in earnings (losses) of unconsolidated affiliates increased primarily due to $50 million favorable net income generated from Exelon s equity investment in CENG and a reduction of $58 million of amortization of the basis difference in CENG recorded at fair value at the merger date.

Interest Expense

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in interest expense is primarily due to the increase in long-term debt as a result of the merger and increased project financing.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in interest expense is primarily due to the increase in long-term debt as a result of the merger.

Other, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase of $129 million in other, net primarily reflects $85 million of credit facility termination fees recorded in 2012 and increased net realized and unrealized gains related to the NDT funds of Generation s Non-Regulatory Agreement Units compared to net realized and unrealized gains in 2012, as described in the table below. Additionally, the increase reflects income related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase of $117 million in other, net primarily reflects a $36 million bargain purchase gain associated with the August 2011 acquisition of Wolf Hollow, $32 million of interest income from a one-time NDT fund special transfer tax deduction in 2011, net realized and unrealized gains related to the NDT funds of Generation s Non-Regulatory Agreement Units compared to net realized and unrealized losses in 2011, as described in the table below, offset by $85 million of credit facility termination fees recorded in 2012. Additionally, the increase reflects income related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for 2013, 2012 and 2011:

	2013	2012	2011
Net unrealized gains (losses) on decommissioning trust funds	$ 146	$ 105	$ (4)
Net realized gains (losses) on sale of decommissioning trust funds	$ 24	$ 51	$ (10)

Effective Income Tax Rate.

Generation s effective income tax rates for the years ended December 31, 2013, 2012 and 2011 were 36.7%, 47.3% and 37.4%, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations ComEd

	2013	2012	Favorable (Unfavorable) 2013 vs. 2012 Variance	2011	Favorable (Unfavorable) 2012 vs. 2011 Variance
Operating revenues	$ 4,464	$ 5,443	$ (979)	$ 6,056	$ (613)
Purchased power expense	1,174	2,307	1,133	3,035	728
Revenues net of purchased power expense [(a)]	3,290	3,136	154	3,021	115
Other operating expenses					
Operating and maintenance	1,368	1,345	(23)	1,189	(156)
Depreciation and amortization	669	610	(59)	554	(56)
Taxes other than income	299	295	(4)	296	1
Total other operating expenses	2,336	2,250	(86)	2,039	(211)
Operating income	954	886	68	982	(96)
Other income and (deductions)					
Interest expense, net	(579)	(307)	(272)	(345)	38
Other, net	26	39	(13)	29	10
Total other income and (deductions)	(553)	(268)	(285)	(316)	48
Income before income taxes	401	618	(217)	666	(48)
Income taxes	152	239	87	250	11
Net income	$ 249	$ 379	$ (130)	$ 416	$ (37)

(a) ComEd evaluates its operating performance using the measure of revenues net of purchased power expense. ComEd believes that revenues 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 revenues net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, revenues 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, 2013, Compared to Year Ended December 31, 2012. ComEd s net income for the year ended December 31, 2013, was lower than the same period in 2012, primarily due to the remeasurement of Exelon s like-kind exchange tax position, partially offset by increased electric distribution revenues, including the impacts of Senate Bill 9, and increased transmission revenues. See Note 3 Regulatory Matters and Note 14 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Year Ended December 31, 2012, Compared to Year Ended December 31, 2011. ComEd s net income for the year ended December 31, 2012, was lower than the same period in 2011, primarily due to increased operating and maintenance expenses, partially offset by increased electric distribution revenues and increased transmission revenues.

Operating Revenues Net of Purchased Power Expense

There are certain drivers of operating revenues that are fully offset by their impact on purchased power expense, such as commodity procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on revenues net of purchased power expense. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd s volume of deliveries, but do affect ComEd s operating revenues related to supplied energy, which is fully offset in purchased power expense. Therefore, customer choice programs have no impact on revenues net of purchased power expense.

The number of retail customers participating in customer choice programs was 2,630,185, 1,627,150 and 380,262 at December 31, 2013, 2012 and 2011, respectively, representing 68%, 43% and 10% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 81%, 65% and 56% of ComEd s retail kWh sales for the years ended December 31, 2013, 2012 and 2011, respectively. During 2012, the City of Chicago and approximately 240 Illinois municipalities, including governmental entities such as townships and counties, approved referenda regarding electric supply aggregation. The referenda allowed governmental officials to identify and sign contracts with competitive electric generation suppliers on behalf of the eligible retail customers in the community, while also allowing customers to opt-out of the municipal aggregation program. As of December 31, 2013, there are approximately 330 municipalities that have approved a municipal aggregation referendum in the ComEd service territory. As a result, approximately 69% of residential usage as of December 31, 2013 is being supplied by competitive electric generation suppliers, and ComEd estimates that over 80% of that usage resulted from municipal aggregation activities.

The changes in ComEd s revenues net of purchased power expense for the year ended 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)
Weather	$ (17)
Volume	(2)
Electric distribution revenues, including impacts of Senate Bill 9	168
Discrete impacts of the 2012 Distribution Rate Case Order	13
Transmission revenues	14
Regulatory required programs	20
Uncollectible accounts recovery, net	(58)
Other	16
Total increase	$ 154

Weather. 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. Conversely, mild weather reduces demand. For the year ended December 31, 2013, the increase in revenues net of purchased power expense was offset by unfavorable weather conditions as a result of the mild weather in 2013, compared to the same period in 2012.

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 the summer months. The changes in heating and cooling degree days in ComEd s service territory for the years ended December 31, 2013 and 2012 consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2013**	**2012**	**Normal**	**From 2012**	**From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	6,603	5,065	6,341	30.4%	4.1%
Cooling Degree-Days	933	1,324	842	(29.5)%	10.8%

Volume. Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, for the year ended December 31, 2013, reflecting decreased average usage per residential customer as compared to the same period in 2012.

Electric Distribution Revenues. EIMA provides for a performance-based formula rate tariff, which requires 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. Distribution revenues vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants. During the year ended December 31, 2013, ComEd recorded increased revenues of $168 million, primarily due to increased capital investments, increased operating expenses, and higher allowed return on common equity, including the impacts of Senate Bill 9. These amounts exclude the discrete impacts of the 2012 Distribution Rate Case Orders, discussed separately below. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Discrete Impacts of the 2012 Distribution Rate Case Orders. On October 3, 2012, the ICC issued its final order related to ComEd s 2011 formula rate proceeding under EIMA (Rehearing Order), which reestablished ComEd s position on the return on its pension asset, resulting in an increase to revenues in 2013. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenues. ComEd s transmission rates are established based on a FERC-approved formula. ComEd s most recent annual formula rate update, filed in April 2013, reflects 2012 actual costs plus forecasted 2013 capital additions. Transmission revenues vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. During the year ended December 31, 2013, ComEd recorded increased revenues of $14 million primarily due to increased capital investments and higher operating expenses. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. Revenues related to regulatory required programs are recoveries from customers for costs of various legislative and regulatory programs on a full and current basis through approved regulated rates. Programs include ComEd s energy efficiency and demand response and purchased power administrative costs. An equal and offsetting amount has been reflected in operating and maintenance expense during the periods presented. See the operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Represents recoveries under ComEd s uncollectible accounts tariff. See the operating and maintenance expense discussion below for additional information on this tariff.

Other. Other revenues, which can vary period to period, include rental revenues, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs and recoveries of environmental costs associated with MGP sites. Other revenues were higher during the year ended December 31, 2013, compared to the same period in 2012, primarily due to recoveries of increased environmental costs associated with MGP sites, for which an equal and offsetting amount expense is reflected in depreciation and amortization expense during the periods presented.

The changes in ComEd s revenues net of purchased power expense for 2012 compared to 2011 consisted of the following:

	Increase (Decrease)
Weather	$ 2
Volume	(4)
Electric distribution revenues	53
Discrete impacts of the 2012 Distribution Rate Case Order	(13)
Transmission revenues	40
Regulatory required programs	32
Uncollectible accounts recovery, net	(28)
Other	33
Total increase	$ 115

Weather. For the year ended December 31, 2012, revenues net of purchased power expense increased due to favorable weather conditions in 2012 compared to the same period in 2011.

The changes in heating and cooling degree days in ComEd s service territory for the years ended December 31, 2012 and 2011 consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2012**	**2011**	**Normal**	**From 2011**	**From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	5,065	6,134	6,341	(17.4)%	(20.1)%
Cooling Degree-Days	1,324	1,036	842	27.8%	57.2%

Volume. Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, for the year ended December 31, 2012, reflecting decreased average usage per residential customer as compared to the same period in 2011.

Electric Distribution Revenues. Under EIMA, ComEd recorded increased revenues during the year ended December 31, 2012 of $53 million, primarily due to increased capital investments and increased operating expenses, partially offset by lower allowed return on common equity. These amounts exclude the discrete impacts of the 2012 Distribution Rate Case Orders discussed separately below. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Discrete Impacts of the 2012 Distribution Rate Case Orders. The May and October 2012 ICC Distribution Rate Case Orders resulted in a reduction to revenues of $13 million in 2012 compared to the same period in 2011. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenues. Based on the FERC-approved formula, ComEd recorded increased revenues during the year ended December 31, 2012 of $40 million, primarily due to increased operating expenses. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Operating and Maintenance Expense

	Year Ended December 31, 2013	Year Ended December 31, 2012	Increase 2013 vs. 2012	Year Ended December 31, 2012	Year Ended December 31, 2011	Increase 2012 vs. 2011
Operating and maintenance expense baseline	$ 1,202	$ 1,199	$ 3	$ 1,199	$ 1,075	$ 124
Operating and maintenance expense regulatory required programs[(a)]	166	146	20	146	114	32
Total operating and maintenance expense	$ 1,368	$ 1,345	$ 23	$ 1,345	$ 1,189	$ 156

(a) Operating and maintenance expense for regulatory required programs are recoveries from customers for costs of various legislative and regulatory programs on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for year ended December 31, 2013, compared to the same period in 2012 and changes for the year ended December 31, 2012, compared to the same period in 2011, consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Baseline		
Labor, other benefits, contracting and materials [(a)]	$ 48	$ 95
Pension and non-pension postretirement benefits expense	3	46
Discrete impacts from 2010 Rate Case order [(b)]		32
Storm-related costs	(10)	(1)
Science and Technology Innovation Trust [(c)]		(11)
Uncollectible accounts expense provision[(d)]	(10)	(14)
Uncollectible accounts expense recovery, net[(d)]	(48)	(14)
Other	20	(9)
	3	124
Regulatory required programs		
Energy efficiency and demand response programs	20	33
Purchased power administrative costs		(1)
	20	32
Increase in operating and maintenance expense	$ 23	$ 156

(a) The increase includes contracting costs resulting from new projects associated with EIMA for the years ended December 31, 2013 and 2012. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding EIMA.

(b) ComEd recorded one-time net benefits in May 2012 as a result of the 2010 Rate Case order to reestablish previously expensed plant balances and to recover previously incurred costs related to Exelon s 2009 restructuring plan.

(c) Under EIMA, ComEd makes recurring payments for contribution to a Science and Technology Innovation Trust fund that will be used to fund energy innovation.

(d) ComEd is allowed to recover from or refund to customers the difference between the utility s annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. In 2013, ComEd recorded a net reduction in operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery and customers purchasing electricity from competitive electric generation suppliers as a result of municipal aggregation. An equal and offsetting reduction has been recognized in operating revenues for the periods presented.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2013 compared to 2012 and 2012 compared to 2011, consisted of the following:

	Increase 2013 vs. 2012	Increase 2012 vs. 2011
Depreciation associated with higher plant balances	$ 22	$ 22
Amortization of storm-related regulatory assets [a]	4	4
Amortization of MGP regulatory assets [b]	27	8
Amortization of other regulatory assets	6	6
Other		16
Increase in depreciation and amortization expense	$ 59	$ 56

(a) Under EIMA, ComEd is required to recover costs associated with significant storms over a five-year period through the amortization of a regulatory asset.
(b) An equal and offsetting amount for the amortization expense related to MGP remediation expenditures is reflected in operating revenues during the periods presented.

Taxes Other Than Income

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income increased primarily due to increased Illinois electricity distribution taxes.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Taxes other than income taxes decreased primarily due to decreased Illinois electricity distribution taxes.

Interest Expense, Net

The changes in interest expense, net for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Interest expense related to uncertain tax positions [a]	$ 281	$
Interest expense on debt (including financing trusts)	2	(26)
Other	(11)	(12)
Increase (decrease) in interest expense, net	$ 272	$ (38)

(a) Primarily reflects the remeasurement of Exelon s like-kind exchange tax position in the first quarter of 2013. See Note 14 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Net

The changes in other, net for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Interest income related to uncertain tax positions [(a)]	$ (20)	$ 16
Gain on asset disposal	5	
Other	2	(6)
Increase in Other, net	$ (13)	$ 10

(a) Primarily reflects a receivable recorded in the fourth quarter of 2012 related to the final 1999-2001 IRS settlement.

Effective Income Tax Rate

ComEd s effective income tax rates for the years ended December 31, 2013, 2012 and 2011, were 37.9%, 38.7% and 37.5%, respectively. See Note 14 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Retail Deliveries to customers (in GWhs)	2013	2012	% Change 2013 vs 2012	Weather-Normal % Change	2011	% Change 2012 vs 2011	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	27,800	28,528	(2.6)%	(0.6)%	28,273	0.9%	(0.6)%
Small commercial & industrial	32,305	32,534	(0.7)%	0.2%	32,281	0.8%	0.2%
Large commercial & industrial	27,684	27,643	0.1%	(0.3)%	27,732	(0.3)%	(0.3)%
Public authorities & electric railroads	1,355	1,272	6.5%	4.2%	1,235	3.0%	4.2%
Total Retail Deliveries	89,144	89,977	(0.9)%	(0.1)%	89,521	0.5%	(0.1)%

Number of Electric Customers	As of December 31, 2013	2012	2011
Residential	3,480,398	3,455,546	3,448,481
Small commercial & industrial	367,569	365,357	365,824
Large commercial & industrial	1,984	1,980	2,032
Public authorities & electric railroads	4,853	4,812	4,797
Total	3,854,804	3,827,695	3,821,134

Electric Revenue	2013	2012	% Change 2013 vs 2012	2011	% Change 2012 vs 2011
Retail Sales [(a)]					
Residential	$ 2,073	$ 3,037	(31.7)%	$ 3,510	(13.5)%
Small commercial & industrial	1,250	1,339	(6.6)%	1,517	(11.7)%
Large commercial & industrial	427	395	8.1%	383	3.1%
Public authorities & electric railroads	48	44	9.1%	50	(12.0)%
Total Retail Sales	3,798	4,815	(21.1)%	5,460	(11.8)%
Other Revenue [(b)]	666	628	6.1%	596	5.4%
Total Electric Revenues	$ 4,464	$ 5,443	(18.0)%	$ 6,056	(10.1)%

(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 and transmission.
(b) Other revenue primarily includes transmission revenue from PJM. Other items include wholesale revenue, rental revenue, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental remediation costs associated with MGP sites, and intercompany revenues.

Results of Operations PECO

	2013	2012	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Operating revenues	$ 3,100	$ 3,186	$ (86)	$ 3,720	$ (534)
Purchased power and fuel	1,300	1,375	75	1,864	489
Revenues net of purchased power and fuel expense [(a)]	1,800	1,811	(11)	1,856	(45)
Other operating expenses					
Operating and maintenance	748	809	61	794	(15)
Depreciation and amortization	228	217	(11)	202	(15)
Taxes other than income	158	162	4	205	43
Total other operating expenses	1,134	1,188	54	1,201	13
Operating income	666	623	43	655	(32)
Other income and (deductions)					
Interest expense, net	(115)	(123)	8	(134)	11
Other, net	6	8	(2)	14	(6)
Total other income and (deductions)	(109)	(115)	6	(120)	5
Income before income taxes	557	508	49	535	(27)
Income taxes	162	127	(35)	146	19
Net income	395	381	14	389	(8)
Preferred security dividends	7	4	3	4	
Net income on common stock	$ 388	$ 377	$ 11	$ 385	$ (8)

(a) PECO evaluates its operating performance using the measures of revenues net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenues net of purchased power expense and revenues net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenues from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenues 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, 2013 Compared to Year Ended December 31, 2012. The increase in net income was driven primarily by lower operating and maintenance expense partially offset by an increase in income taxes.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in net income was driven primarily by lower operating revenues net of purchased power and fuel expense and increased storm costs. The decrease in revenues net of purchased power and fuel expense was primarily related to unfavorable weather and a decline in electric load. The decrease to net income was partially offset by lower taxes other than income, interest expense and income taxes.

Operating Revenues Net of Purchased Power and Fuel Expense

Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO s electric supply and natural gas cost rates charged to customers are subject to adjustments at least quarterly that 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 expense.

Electric and gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the customer choice program. All PECO customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customer s choice of suppliers does not impact the volume of deliveries, but affects revenues collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and gas revenues net of purchase power and fuel expense. The number of retail customers purchasing energy from a competitive electric generation supplier was 531,500, 496,500, and 387,600 at December 31, 2013, 2012 and 2011, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 68%, 66%, and 57% of PECO s retail kWh sales for the years ended December 31, 2013, 2012 and 2011, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 66,400, 53,600, and 24,800 at December 31, 2013, 2012 and 2011, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 19%, 16%, and 11% of PECO s mmcf sales for the years ended December 31, 2013, 2012 and 2011, respectively.

The changes in PECO s operating revenues net of purchased power and fuel expense for the year ended December 31, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
Weather	$ 6	$ 31	$ 37
Volume	(3)	(3)	(6)
Pricing	(14)	2	(12)
Regulatory required programs	(6)		(6)
Gross receipts tax	(8)		(8)
Gas distribution tax repair		(8)	(8)
Other	(7)	(1)	(8)
Total decrease	$ (32)	$ 21	$ (11)

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. Operating revenues net of purchased power and fuel expense were higher due to the impact of favorable 2013 winter weather conditions.

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, 2013 compared to the same period in 2012 and normal weather consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2013**	**2012**	**Normal**	**From 2012**	**From Normal**
Twelve Months Ended December 31,					

Heating Degree-Days	4,474	3,747	4,603	19.4%	(2.8)%
Cooling Degree-Days	1,411	1,603	1,301	(12.0)%	8.5%

Volume

The decrease in electric revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflects the impact of energy efficiency initiatives on customer usages as well as a shift in the volume profile across classes from higher priced classes to lower priced classes, partially offset by the oil refineries returning to full production in 2013 as well as moderate economic growth. The decrease in gas revenues net of fuel expense related to delivery volume, exclusive of the effects of weather, primarily reflects a decline in Residential use per customer.

Pricing

The decrease in electric operating revenues net of purchased power expense as a result of pricing is primarily attributable to lower overall effective rates due to increased usage across all major customer classes.

Regulatory Required Programs

This represents the change in operating revenues collected under approved riders to recover costs incurred for the smart meter, energy efficiency and consumer education programs as well as the administrative costs for the GSA and AEPS programs. The riders are designed to provide full and current cost recovery as well as a return. The offsetting costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Gross Receipts Tax

GRT is an excise tax on total electric revenues. As a result of decreases in operating revenues compared to 2012, GRT decreased. Equal and offsetting decreases in GRT have been reflected in taxes other than income.

Gas Distribution Tax Repair

The decrease in gas distribution tax repair reflects the 2012 tax benefit received from prior period gas distribution repairs for the 2011 tax year. There is an equal and offsetting tax benefit in operating revenues, see NOTE 3 Regulatory Matters for further explanation.

Other

The decrease in other electric revenues net of purchased power expense compared to the year ended December 31, 2012 reflects a decrease in wholesale transmission revenues earned by PECO due to higher peak loads in the previous years.

The changes in PECO s operating revenues net of purchased power and fuel expense for the year ended December 31, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
Weather	$ (17)	$ (15)	$ (32)
Volume	(22)		(22)
Pricing	(4)	3	(1)
Regulatory required programs	29		29
Gross receipts tax	(27)		(27)
Other	8		8
Total increase (decrease)	$ (33)	$ (12)	$ (45)

Weather

Electric and gas revenues net of purchased power and fuel expense were lower due to unfavorable winter weather conditions during 2012 in PECO s service territory.

The changes in heating and cooling degree days in PECO s service territory for the year ended December 31, 2012 compared to the same period in 2011 and normal weather consisted of the following:

Heating and Cooling Degree-Days [(a)]	**2012**	**2011**	**Normal**	**% Change From 2011**	**% Change From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	3,747	4,157	4,603	(9.9)%	(18.6)%
Cooling Degree-Days	1,603	1,617	1,301	(0.9)%	23.2%

Volume

The decrease in electric revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflected the reduced oil refinery load in PECO s service territory and the impact of energy efficiency initiatives and weak economic conditions on customer usage. See Note 3 of the Combined Notes to Consolidated Financial Statements for further information regarding energy efficiency initiatives.

Pricing

The decrease in electric operating revenues net of purchased power expense as a result of pricing is primarily attributable to lower overall effective rates due to increased usage across all major customer classes.

Regulatory Required Programs

This represents the change in operating revenues collected under approved riders to recover costs incurred for the smart meter, energy efficiency and consumer education programs as well as the administrative costs for the GSA and AEPS programs. The riders are designed to provide full and current cost recovery as well as a return. The offsetting costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Other

The decrease in other electric revenues net of purchased power expense primarily reflected a decrease in GRT revenues as a result of lower supplied energy service and a reduction in the GRT rate. There is an equal and offsetting decrease in GRT expense included in taxes other than income.

Operating and Maintenance Expense

	Twelve Months Ended December 31,		Increase (Decrease)	Twelve Months Ended December 31,		Increase (Decrease)
	2013	2012	2013 vs. 2012	2012	2011	2012 vs. 2011
Operating and Maintenance Expense Baseline	$ 668	$ 723	$ (55)	$ 723	$ 725	$ (2)
Operating and Maintenance Expense Regulatory Required Programs [(a)]	80	86	(6)	86	69	17
Total Operating and Maintenance Expense	$ 748	$ 809	$ (61)	$ 809	$ 794	$ 15

(a) 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.

The changes in operating and maintenance expense for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Baseline		
Labor, other benefits, contracting and materials	$ 10	$ (29)
Storm-related costs	(49)	9[(a)]
Pension and non-pension postretirement benefits expense	(12)	
Constellation merger and integration costs	(8)	15
Other	4	3
	(55)	(2)
Regulatory Required Programs		
Smart Meter	4	12
Energy Efficiency	(9)	8
GSA		(1)
Consumer education program	(1)	(1)
AEPS		(1)
	(6)	17
Increase (decrease) in operating and maintenance expense	$ (61)	$ 15

(a) Storm-related costs include $46 million of incremental storm costs incurred in the fourth quarter of 2012 as a result of Hurricane Sandy. This expense was significantly offset by the costs incurred related to Hurricane Irene and other storms throughout 2011.

Depreciation and Amortization Expense

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in depreciation and amortization expense, net for 2013, compared to 2012 was primarily due to ongoing capital expenditures.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in depreciation and amortization expense, net for 2012 compared to 2011 was primarily due to ongoing capital expenditures.

Taxes Other Than Income

The change in taxes other than income for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
GRT expense	$ (12)	$ (33)
Sales and use tax	8	(12)[a]
Other		2
Decrease in taxes other than income	$ (4)	$ (43)

(a) The decrease reflects a sales and use tax reserve adjustment in the first quarter of 2012 resulting from the completion of the audit of tax years 2005 through 2010.

Interest Expense, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in interest expense, net for 2013 compared to 2012 was primarily due to refinancing debt at lower interest rates during the second half of 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in interest expense, net for 2012 compared to 2011 was primarily due to the debt retirement in November 2011.

Other, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Other, net remained relatively level between periods.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in Other, net for 2012 compared to 2011 was due to decreased AFUDC Equity. See Note 20 of the Combined Notes to Consolidated Financial Statements in the 2012 10-K for additional details of the components of Other, net.

Effective Income Tax Rate

PECO s effective income tax rates for the years ended December 31, 2013, 2012 and 2011 were 29.1%, 25.0% and 27.3%, respectively. The increase in effective income tax rate in 2013 compared 2012 reflects the 2012 impact of the tax benefit received from electing to change the method of accounting for gas distribution property for the 2011 tax year. See Note 14 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)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	13,341	13,233	0.8%	(0.0)%	13,687	(3.3)%	(1.7)%
Small commercial & industrial	8,101	8,063	0.5%	(1.1)%	8,321	(3.1)%	(2.3)%
Large commercial & industrial	15,379	15,253	0.8%	1.5%	15,677	(2.7)%	(2.7)%
Public authorities & electric railroads	930	943	(1.4)%	(1.4)%	945	(0.2)%	(0.2)%
Total Electric Retail Deliveries	37,751	37,492	0.7%	0.3%	38,630	(2.9)%	(2.2)%

Number of Electric Customers	As of December 31, 2013	2012	2011
Residential	1,423,068	1,417,773	1,415,681
Small commercial & industrial	149,117	148,803	148,570
Large commercial & industrial	3,105	3,111	3,110
Public authorities & electric railroads	9,668	9,660	9,689
Total	1,584,958	1,579,347	1,577,050

Electric Revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales [a]					
Residential	$ 1,592	$ 1,689	(5.7)%	$ 1,934	(12.7)%
Small commercial & industrial	433	462	(6.3)%	585	(21.0)%
Large commercial & industrial	224	232	(3.4)%	308	(24.7)%
Public authorities & electric railroads	30	31	(3.2)%	38	(18.4)%
Total Retail	2,279	2,414	(5.6)%	2,865	(15.7)%
Other Revenue [b]	221	226	(2.2)%	244	(7.4)%
Total Electric Revenues	$ 2,500	$ 2,640	(5.3)%	$ 3,109	(15.1)%

(a) Reflects delivery volumes and revenues 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 wholesale electric revenues.

PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries [b]							
Retail sales	57,613	49,767	15.8%	(0.1)%	54,239	(8.2)%	(0.1)%
Transportation and other	28,089	26,687	5.3%	0.5%	28,204	(5.4)%	(4.8)%
Total Gas Deliveries	85,702	76,454	12.1%	0.1%	82,443	(7.3)%	(1.6)%

Number of Gas Customers	As of December 31, 2013	2012	2011
Residential	458,356	454,502	451,382
Commercial & industrial	42,174	41,836	41,373
Total Retail	500,530	496,338	492,755
Transportation	909	903	879
Total	501,439	497,241	493,634

Gas revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales [(a)]					
Retail sales	$ 562	$ 509	10.4%	$ 576	(11.6)%
Transportation and other	38	37	2.7%	35	5.7%
Total Gas Revenues	$ 600	$ 546	9.9%	$ 611	(10.6)%

(a) Reflects delivery volumes and revenues 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. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

Results of Operations BGE

	2013	2012	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Operating revenues	$ 3,065	$ 2,735	$ 330	$ 3,068	$ (333)
Purchased power and fuel expense	1,421	1,369	(52)	1,593	224
Revenue net of purchased power and fuel expense [(a)]	1,644	1,366	278	1,475	(109)
Other operating expenses					
Operating and maintenance	634	728	94	680	(48)
Depreciation and amortization	348	298	(50)	274	(24)
Taxes other than income	213	208	(5)	207	(1)
Total other operating expenses	1,195	1,234	39	1,161	(73)
Operating income	449	132	317	314	(182)
Other income and (deductions)					
Interest expense, net	(122)	(144)	22	(129)	(15)
Other, net	17	23	(6)	26	(3)
Total other income and (deductions)	(105)	(121)	16	(103)	(18)
Income before income taxes	344	11	333	211	(200)
Income taxes	134	7	(127)	75	68
Net income	210	4	206	136	(132)
Preference stock dividends	13	13		13	
Net income (loss) attributable to common shareholder	$ 197	$ (9)	$ 206	$ 123	$ (132)

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

Net Income

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in net income was driven primarily by higher distribution rates as a result of the 2012 rate order issued by MDPSC and decreased operating revenues net of purchased power and fuel expense in 2012 related to the accrual of the residential customer rate credit provided as a condition of the MDPSC s approval of Exelon s merger with Constellation. Additionally, the increase in net income was also driven by higher operating and maintenance expenses in 2012, primarily related to BGE s accrual of its portion of the charitable contributions to be provided as a condition of the MDPSC s approval of the merger and lower storm restoration costs in 2013.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in net income was driven primarily by decreased operating revenues net of purchased power and fuel expense related to the residential customer rate credit provided as a condition of the MDPSC s approval of Exelon s merger with Constellation. The decrease in net income was also driven by increased operating and maintenance expenses, primarily related to BGE s accrual of its portion of the charitable contributions to be provided as a condition of the MDPSC s approval of the merger as well as merger transaction costs, and increased depreciation and amortization expense. None of the customer rate credit, the charitable contributions, or the transaction costs are recoverable from BGE s customers.

Operating Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE s electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC s market-based SOS and gas commodity programs, respectively.

The number of customers electing to select a competitive electric generation supplier affects electric SOS revenues and purchased power expense. The number of customers electing to select a competitive natural gas supplier affects gas cost adjustment revenues and purchased natural gas expense. All BGE customers have the choice to purchase energy from a competitive electric generation supplier. This customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to SOS. The number of retail customers purchasing electricity from a competitive electric generation supplier was 399,000, 362,000 and 314,000 at December 31, 2013, 2012 and 2011, respectively, representing 32%, 29% and 25% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 61%, 60% and 58% of BGE s retail kWh sales for the years ended December 31, 2013, 2012 and 2011, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 172,000, 143,000 and 118,000 at December 31, 2013, 2012 and 2011, respectively, representing 26%, 22% and 18% of total retail customers, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 54%, 56% and 52% of BGE s retail mmcf sales for the years ended December 31, 2013, 2012 and 2011, respectively.

The changes in BGE s operating revenues net of purchased power and fuel expense for the year ended December 31, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
2012 Residential customer rate credit [a]	$ 82	$ 31	$ 113
Pricing	69	24	93
Regulatory program cost recovery	36	6	42
Other	26	4	30
Total increase	$ 213	$ 65	$ 278

(a) In accordance with the MDPSC order approving Exelon s merger with Constellation, the residential customer rate credit is not recoverable from BGE s customers. Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

Revenue Decoupling. The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE s electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class,

regardless of changes in consumption levels. This allows BGE to recognize revenues at MDPSC-approved levels per customer, regardless of what BGE s actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE s service territory. The changes in heating degree days in BGE s service territory for the year ended December 31, 2013 compared to the same period in 2012 and normal weather consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2013**	**2012**	**Normal**	**From 2012**	**From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	4,744	3,960	4,661	19.8%	1.8%
Cooling Degree-Days	869	1,022	864	(15.0)%	0.6%

2012 Residential Customer Rate Credit.

The increase in operating revenues net of purchased power and fuel expense for the year ended December 31, 2013 compared to the same period in 2012 was due to the residential customer rate credit provided in 2012 as a result of the MDPSC s order approving Exelon s merger with Constellation.

Pricing.

The increase in operating revenues net of purchased power and fuel expense as a result of pricing for the year ended December 31, 2013 compared to the same period in 2012 was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective February 23, 2013 and December 13, 2013 in accordance with the MDPSC approved electric and natural gas distribution rate case order. See Note 3 Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for further information.

Regulatory Required Programs.

This represents the change in revenues collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in revenues during the year ended December 31, 2013 compared to the same period in 2012 was due to the recovery of higher energy efficiency program costs.

Other.

Other revenues increased during the year ended December 31, 2013 compared to the same period in 2012. Other revenues, which can vary from period to period, include miscellaneous revenues such as service application and late payment fees.

The changes in BGE s operating revenues net of purchased power and fuel expense for the year ended December 31, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
2012 Residential customer rate credit	$ (82)	$ (31)	$ (113)
Commodity margin	(1)	(5)	(6)
Regulatory program cost recovery	15	4	19
Transmission	11		11
Other	(13)	(7)	(20)
Total decrease	$ (70)	$ (39)	$ (109)

The changes in heating and cooling degree days for the twelve months ended 2012 and 2011, consisted of the following:

				% Change	
Heating and Cooling Degree-Days [(a)]	**2012**	**2011**	**Normal**	**From 2011**	**From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	3,960	4,326	4,711	(8.5)%	(15.9)%
Cooling Degree-Days	1,022	1,035	858	(1.3)%	19.1%

2012 Residential Customer Rate Credit

The residential customer rate credit provided as a result of the MDPSC s order approving Exelon s merger with Constellation decreased operating revenues net of purchased power and fuel expense for the year ended December 31, 2012.

Commodity Margin

The commodity margin for both electric and gas revenues decreased during the year ended December 31, 2012 compared to the same period in 2011 due to an increase in the number of customers using competitive suppliers in 2012.

Regulatory Required Programs

This represents the change in revenues collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in revenues during the year ended December 31, 2012 compared to the same period in 2011 was due to the recovery of higher energy efficiency programs costs.

Transmission

Transmission revenues increased during the year ended December 31, 2012 compared to the same period in 2011 due to higher revenue requirements. BGE s transmission rates are established based on a FERC-approved formula. The rates also include transmission investment incentives approved by FERC in a number of orders covering various new transmission investment projects since 2007.

Other

Other revenues decreased during the year ended December 31, 2012 compared to the same period in 2011. Other revenues, which can vary from period to period, include miscellaneous revenues such as service application and late payment fees.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Charitable contributions [a]	$ (28)	$ 28
Storm costs deferral [b]		16
Storm-related costs [c]	(62)	7
Pension and non-pension postretirement benefits expense		6
Labor, other benefits, contracting and materials	20	(10)
Merger transaction costs [a]	(21)	(9)
Other	(3)	10
(Decrease) Increase in operating and maintenance expense	$ (94)	$ 48

(a) During the first quarter of 2012, BGE accrued $28 million in charitable contributions as a result of BGE s merger-related commitments. The charitable contribution accrual and merger costs are not recoverable from BGE s customers.

(b) During the first quarter of 2011, the MDPSC issued a comprehensive rate order permitting the deferral of incremental distribution service restoration expenses associated with 2010 storms as a regulatory asset.

(c) On June 29, 2012, a Derecho storm caused extensive damage to BGE s electric distribution system and created power outages that lasted multiple days. As a result, BGE incurred $62 million of incremental costs during the year ended December 31, 2012, of which $20 million are capital costs. In the fourth quarter of 2012, BGE incurred $38 million of incremental costs as a result of Hurricane Sandy, of which $14 million are capital costs. These amounts compare to $40 million of incremental expenses incurred during the third quarter of 2011 associated with Hurricane Irene, of which $25 million are capital costs, and $14 million of incremental expenses, of which $3 are capital costs, incurred during the first quarter of 2011.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Depreciation expense [a]	$18	$ 20

Regulatory asset amortization [b]	31	6
Other	1	(2)
Increase in depreciation and amortization expense	$50	$ 24

(a) Deprecation and amortization expense increased due to higher plant balances year over year.
(b) Regulatory asset amortization increased due to higher energy efficiency and demand response programs expenditures year over year

Taxes Other Than Income

The change in taxes other than income for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Property tax	$ (2)	$ 4
Franchise tax	7	(1)
Other		(2)
Increase in taxes other than income	$ 5	$ 1

Interest Expense, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in interest expense, net for 2013 compared to 2012 was primarily due to the interest recorded in 2012 on prior year tax liabilities and lower effective interest rates as a result of the refinancing of debt at a lower interest rate in 2013.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in interest expense, net in 2012 compared to 2011 was primarily due to higher outstanding debt balances and interest recorded in 2012 on prior year tax liabilities.

Effective Income Tax Rate

BGE s effective income tax rates for the years ended December 31, 2013, 2012 and 2011 were 39.0%, 63.6% and 35.5%, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	13,077	12,719	2.8%	n.m.	12,652	0.5%	n.m.
Small commercial & industrial [(c)]	3,035	2,990	1.5%	n.m.	3,023	(1.1)%	n.m.
Large commercial & industrial [(c)]	14,339	14,956	(4.1)%	n.m.	15,729	(4.9)%	n.m.
Public authorities & electric railroads	317	329	(3.6)%	n.m.	405	(18.8)%	n.m.

Total Electric Retail Deliveries	30,768	30,994	(0.7)%	n.m.	31,809	(2.6)%	n.m.

	As of December 31,		
Number of Electric Customers	**2013**	**2012**	**2011**
Residential	1,120,431	1,116,233	1,116,401
Small commercial & industrial [c]	112,850	112,994	113,026
Large commercial & industrial [c]	11,652	11,580	11,365
Public authorities & electric railroads	292	319	326
Total	1,245,225	1,241,126	1,241,118

Electric Revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales [(a)]					
Residential	$ 1,404	$ 1,274	10.2%	$ 1,456	(12.5)%
Small commercial & industrial [(c)]	257	248	3.6%	268	(7.5)%
Large commercial & industrial [(c)]	439	393	11.7%	416	(5.5)%
Public authorities & electric railroads	31	30	3.3%	29	3.4%
Total Retail	2,131	1,945	9.6%	2,169	(10.3)%
Other Revenue [(b)]	274	238	15.1%	152	56.6%
Total Electric Revenues	$ 2,405	$ 2,183	10.2%	$ 2,321	(5.9)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes wholesale transmission revenue and late payment charges.
(c) Certain commercial and industrial (C&I) customers were reclassified from small C&I to large C&I in prior years to conform to the current year s classification of C&I customers.

BGE Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries [(d)]							
Retail sales	94,020	86,946	8.1%	n.m.	94,800	(8.3)%	n.m.
Transportation and other [(e)]	12,210	15,751	(22.5)%	n.m.	16,436	(4.2)%	n.m.
Total Gas Deliveries	106,230	102,697	3.4%	n.m.	111,236	(7.7)%	n.m.

Number of Gas Customers	As of December 31, 2013	2012	2011
Residential	611,532	610,827	608,943
Commercial & industrial	44,162	44,228	44,211
Total	655,694	655,055	653,154

Gas revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales [(d)]					
Retail sales	$ 592	$ 494	19.8%	$ 580	(14.8)%
Transportation and other [(e)]	68	58	17.2%	92	(37.0)%
Total Gas Revenues	$ 660	$ 552	19.6%	$ 672	(17.9)%

(d) Reflects delivery revenues and volumes from customers purchasing natural gas directly from BGE 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 BGE.

(e) Transportation and other gas revenue includes off-system revenue of 12,210 mmcfs ($55 million), 15,751 mmcfs ($51 million), and 16,436 mmcfs ($82 million) for the years ended 2013, 2012 and 2011, respectively.

Liquidity and Capital Resources

Exelon s and Generation s prior year activity presented below includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. Exelon s and Generation s activity for 2011 is unadjusted for the effects of the merger. BGE s prior year activity presented below includes its activity for the 12 months ended December 31, 2012 and 2011.

The Registrants operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants businesses are capital intensive and require considerable capital resources. Each Registrant s access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon, Generation, ComEd, PECO and BGE have access to unsecured revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. The Registrants revolving credit facilities are in place until 2018. In addition, Generation has $0.4 billion in bilateral facilities with banks which expire in January 2015, December 2015 and March 2016. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the Credit Matters section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO and BGE 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 13 of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants debt and credit agreements.

Cash Flows from Operating Activities

General

Generation s cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to 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, PECO s and BGE s cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO and BGE, gas distribution services. ComEd s, PECO s and BGE s distribution services are provided to an established and diverse base of retail customers. ComEd s, PECO s and BGE 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, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 3 and 22 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. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law were applied in 2012 while others take effect in 2013. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to contribute approximately $264 million to its pension plans in 2014, of which Generation, ComEd, PECO and BGE expect to contribute $118 million, $119 million, $11 million and $0 million, respectively. See Note 16 of the Combined Notes to Consolidated Financial Statements for the Registrants 2013 and 2012 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 $430 million to the other postretirement benefit plans in 2014, of which Generation, ComEd, PECO and BGE expect to contribute $168 million, $197 million, $19 million and $17 million, respectively. See Note 16 of the Combined Notes to Consolidated Financial Statements for the Registrants 2013 and 2012 other postretirement benefit contributions.

See the Contractual Obligations section below for management s estimated future pension and other postretirement benefits contributions.

Tax Matters

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

Exelon, Generation, ComEd, PECO and BGE expect to receive tax refunds of approximately $380 million, $60 million, $320 million, $10 million and $20 million, respectively, between 2014 and 2015.

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.

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The newly adopted method results in a cash tax benefit in 2012 of approximately $38 million and $41 million at Exelon and PECO, respectively. Exelon currently anticipates that the IRS will issue industry guidance in the near future. See Note 3 of the Combined Notes to Consolidated Financial Statements for discussion regarding the regulatory treatment of PECO s tax benefits from the application of the method change.

The following table provides a summary of the major items affecting Exelon s cash flows from operations for the years ended December 31, 2013, 2012 and 2011:

	2013	2012	2013 vs. 2012 Variance	2011	2012 vs. 2011 Variance
Net income	$ 1,729	$ 1,171	$ 558	$ 2,499	$ (1,328)
Add (subtract):					
Non-cash operating activities [a]	4,159	5,588	(1,429)	4,848	740
Pension and non-pension postretirement benefit contributions	(422)	(462)	40	(2,360)	1,898
Income taxes	883	544	339	492	52
Changes in working capital and other noncurrent assets and liabilities [b]	(185)	(731)	546	(279)	(452)
Option premiums paid, net	(36)	(114)	78	(3)	(111)
Counterparty collateral received (paid), net	215	135	80	(344)	479
Net cash flows provided by operations	$ 6,343	$ 6,131	$ 212	$ 4,853	$ 1,278

(a) Represents depreciation, amortization, depletion and accretion, net fair value changes related to derivatives, 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 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon [a]	$ 6,343	$ 6,131	$ 4,853
Generation [a]	3,887	3,581	3,313
ComEd	1,218	1,334	836
PECO	747	878	818
BGE [a]	561	485	476

(a) Exelon s and Generation s prior year activity includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. Exelon s and Generation s activity for 2011 is unadjusted for the effects of the merger. BGE s prior year activity includes its activity for the 12 months ended December 31, 2012 and 2011.

Changes in Exelon s, Generation s, ComEd s, PECO s and BGE 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 2013, 2012 and 2011 were as follows:

Generation

During 2013, 2012 and 2011, Generation had net (payments) receipts of counterparty collateral of $162 million, $95 million and $(410) million, respectively. Net payments during 2013 and 2012 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 with 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 2013, 2012 and 2011, Generation s accounts receivable from ComEd increased (decreased) by $(16) million, $(15) million and $12 million, respectively, primarily due to changes in receivables for energy purchases related to its SFC, ICC-approved RFP contracts and financial swap contract.

During 2013, 2012 and 2011, Generation s accounts receivable from PECO increased (decreased) by $(17) million, $17 million and $(210) million, respectively.

During 2013, 2012 and 2011, Generation s accounts receivable from BGE increased (decreased) by $(4) million, $23 million and $(13) million, respectively.

During 2013, 2012 and 2011, Generation had net payments of approximately $36 million, $114 million and $3 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 2013, 2012 and 2011, 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 $(16) million, $(15) million and $12 million, respectively. During 2013, 2012 and 2011, ComEd s payables to other energy suppliers for energy purchases increased (decreased) by $35 million, $20 million and $(43) million, respectively.

During 2013, 2012, and 2012, ComEd received $53 million, $37 million and $63 million, respectively, of incremental cash collateral from PJM due to variations in its energy transmission activity levels. As of December 31, 2013 and December 31, 2012, ComEd had cash collateral remaining at PJM of $0M and $53 million, respectively.

PECO

During 2013, 2012 and 2011, PECO s payables to Generation for energy purchases increased (decreased) by $(17) million, $17 million and $(210) million, respectively, and payables to other energy suppliers for energy purchases increased (decreased) by $33 million, $(22) million and $97 million, respectively.

BGE

During 2013, 2012 and 2011, BGE s payables to Generation for energy purchases increased (decreased) by $(4) million, $23 million and $(13) million, respectively, and payables to other energy suppliers for energy purchases increased (decreased) by $5 million, $40 million and $(60) million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for 2013, 2012, and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon (a)(c)(f)	$ (5,394)	$ (4,576)	$ (4,603)
Generation (a)(c)(f)	(2,916)	(2,629)	(3,077)
ComEd	(1,387)	(1,212)	(1,007)

PECO	(531)	(328)	(557)
BGE [f]	(571)	(573)	(592)

Capital expenditures by Registrant for 2013, 2012 and 2011 and projected amounts for 2014 are as follows:

	Projected 2014 [b]	2013	2012	2011 [a]
Exelon [f]	$ 5,475	$ 5,395	$ 5,789	$ 4,042
Generation [c][f]	2,400	2,752	3,554	2,491
ComEd [d]	1,775	1,433	1,246	1,028
PECO	625	537	422	481
BGE [f]	600	587	582	592
Other [e]	75	86	82	42

(a) Includes $387 million in 2011 related to acquisitions, principally acquisition of Wolf Hollow, Antelope Valley and Shooting Star. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Total projected capital expenditures do not include adjustments for non-cash activity.
(c) Includes nuclear fuel.
(d) Pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology. ComEd expects to file an updated investment plan with the ICC in April, 2014.
(e) Other primarily consists of corporate operations and BSC.
(f) Exelon s and Generation s prior year activity includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. Exelon s and Generation s activity for 2011 is unadjusted for the effects of the merger. BGE s prior year activity includes its activity for the 12 months ended December 31, 2012 and 2011.

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

Generation

Approximately 38% and 11% of the projected 2014 capital expenditures at Generation are for the acquisition of nuclear fuel and investments in renewable energy generation, including Antelope Valley construction costs, 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 2014 capital expenditures are a portion of the costs of a series of planned power uprates across Generation s nuclear fleet. See EXELON CORPORATION Executive Overview, for more information on nuclear uprates.

On November 30, 2012, a subsidiary of Generation sold three Maryland generating stations and associated assets to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC, and received net proceeds of approximately $371. In addition, Generation will begin to make cash payments of approximately $31 million to Raven Power Holdings LLC over a twelve-month period beginning in June 2014. In 2012, Generation incurred transaction costs of approximately $15 million through the date of closing of the transaction. The sale will generate approximately $195 million of cash tax benefits, of which $155 million will be realized in periods through 2014 with the balance to be received in later years. Therefore, Generation expects net after-tax cash sale proceeds of approximately $495 million through 2014 and approximately $36 million in subsequent years.

ComEd, PECO and BGE

Approximately 91%, 72% and 89% of the projected 2014 capital expenditures at ComEd, PECO and BGE, 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 s, PECO s and BGE s construction commitments under PJM s RTEP. ComEd s capital expenditures include smart grid/smart meter technology required under EIMA. PECO and BGE capital expenditures include investments related to their respective smart meter program and SGIG project, net of DOE expected reimbursements. The remaining amounts are for capital additions to support new business and customer growth. See Notes 3 and 7 of the Combined Notes to Consolidated Financial Statements for additional information.

In 2010, NERC provided guidance to transmission owners, including ComEd, PECO, and BGE, that recommends the completion of performance assessments of 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, PECO and BGE submitted their most recent bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will incur 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, PECO s and BGE s forecasted 2014 capital expenditures above reflect capital spending for remediation to be completed in 2014.

ComEd, PECO and BGE 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 3 of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon	$ (826)	$ (1,085)	$ (846)
Generation	(384)	(777)	(196)
ComEd	61	(212)	355
PECO	(361)	(382)	(589)
BGE	(48)	128	115

Debt.Debt activity for 2013, 2012 and 2011 by Registrant was as follows:

Company	Issuances of long-term debt in 2013	Use of proceeds
Generation	$5 million of variable rate CEU Credit Agreement project financing, due July 22, 2016	Used to fund Upstream gas activities
Generation	$227 million of fixed rate DOE Project Financing, due January 5, 2037	Used for Antelope Valley solar development
Generation	$1 million of 2.93% Social Security Administration Project Financing, due February 18, 2015	Used to install conservation measures for the Social Security Administration Headquarters facility in Maryland
Generation	$9 million of 4.40% Energy Efficiency Financing, due August 31, 2014	Used for funding to install energy conservation measures in Beckley, West Virginia
Generation	$613 million of 6.00% Continental Wind Senior Secured Notes, due February 28, 2033	Used for general corporate purposes

Company	Issuances of long-term debt in 2013	Use of proceeds
ComEd	$350 million of First Mortgage 4.60% Bonds, Series 114, due August 15, 2043	Used to repay outstanding commercial paper obligations and for general corporate purposes
PECO	$300 million of First and Refunding Mortgage 1.20% Bonds due October 15, 2016	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
PECO	$250 million of First and Refunding Mortgage 4.80% Bonds due October 15, 2043	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
BGE	$300 million of fixed rate 3.35% Notes due July 1, 2023	Used to partially refinance Notes due July 1, 2013 and for general corporate purposes

Company	Issuances of long-term debt in 2012	Use of proceeds
Generation	$78 million of variable rate CEU Credit Agreement project financing, due July 16, 2016	Used to fund Upstream gas activities
Generation	$220 million of fixed rate DOE Project Financing, due January 5, 2037	Used for Antelope Valley solar development
Generation	$523 million of 4.25% Senior Notes due June 15, 2022	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	$788 million of 5.60% Senior Notes due June 15, 2042	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	$38 million of variable rate Clean Horizons project financing due June 7, 2030	Used for funding for Maryland solar development
ComEd	$350 million of First Mortgage 3.80% Bonds, Series 113, due October 1, 2042	Used to repay outstanding commercial paper obligations and for general corporate purposes
PECO	$350 million of First and Refunding Mortgage 2.38% Bonds due September 15, 2022	Used to pay at maturity First Mortgage Bonds due October 1, 2012 and for general corporate purposes
BGE	$250 million of fixed rate 2.80% Notes due August 15, 2022	Used to repay total outstanding commercial paper obligations and for general corporate purposes

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, $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes

Company	Issuances of long-term debt in 2011	Use of proceeds
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, $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes
BGE	$300 million of fixed rate 3.50% Notes, due November 15, 2021	Used to repay total outstanding commercial paper obligations and for general corporate purposes

Company	Retirement of long-term debt in 2013
Generation	$3 million scheduled payments of 7.83% Kennett Square capital lease until September 1, 2020
Generation	$113 million of variable rate Solar Revolver project financing with a final maturity of July 7, 2014
Generation	$2 million of 2.563% project financing Clean Horizons with a final maturity of September 7, 2030
Generation	$2 million of 2.68% Sacramento Energy Loan Agreement with a final maturity of December 31, 2030
Generation [(a)]	$450 million of 8.625% Series A Junior Subordinated Debentures with a final maturity of June 15, 2063
ComEd	$125 million of 7.625% First Mortgage Bonds, Series 92, due April 15, 2013
ComEd	$127 million of 7.500% First Mortgage Bonds, Series 94, due July 1, 2013
PECO	$300 million of 5.600% First and Refunding Mortgage Bonds, due October 15, 2013
BGE	$67 million of 5.72% fixed rate Rate Stabilization Bonds, due April 1, 2017
BGE	$400 million of 6.125% Senior Notes, due July 1, 2013

Company	Retirement of long-term debt in 2012
Exelon	$2 million of 7.30% fixed-rate Medium Term Notes with a maturity date of June 1, 2012
Exelon	$442 million of 7.60% fixed-rate Senior Notes with a maturity date of April 1, 2032
Generation	$2 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
Generation	$46 million of 3-year term rate Armstrong Co. 2009 A, Pollution Control Notes at 5.00% with a final maturity of December 1, 2042
Generation	$89 million of variable rate project financing CEU Credit Agreement with a final maturity of July 16, 2016
Generation	$17 million of variable rate Solar Revolver project financing with a final maturity of July 7, 2014
Generation	$75 million of variable rate MEDCO tax-exempt bonds with a final maturity of April 1, 2024
Generation	$2 million of variable rate Sacramento Solar Promissory Note with a final maturity of March 12, 2012
ComEd	$450 million of 6.15% First Mortgage Bonds, Series 98, due March 15, 2012

Company	Retirement of long-term debt in 2012
PECO	$225 million of 4.75% First and Refunding Mortgage Bonds, due October 1, 2012
PECO	$150 million of 4.00% First and Refunding Mortgage Bonds, due December 1, 2012
BGE	$8 million of 5.72% fixed rate Rate Stabilization Bonds, due April 1, 2016
BGE	$55 million of 5.47% fixed rate Rate Stabilization Bonds, due October 1, 2012
BGE	$110 million of variable rate Medium Term Notes, due June 15, 2012

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
BGE	$60 million of 5.47% fixed rate Rate Stabilization Bonds, due October 1, 2012

(a) Represents debt obligations assumed by Exelon as part of the merger on March 12, 2012 that became callable at face value on June 15, 2013. Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable as of December 31, 2012 included in long-term debt to affiliate on Generation s Consolidated Balance Sheets and notes receivable from affiliates at Exelon Corporate, which are eliminated in consolidation on Exelon s Consolidated Balance Sheets. The third-party debt obligations were reported in Long-term Debt on Exelon s Consolidated Balance Sheets as of December 31, 2012. The debentures were redeemed and the intercompany loan agreements repaid on June 15, 2013.

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 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon	$ 1,263	$ 1,733	$ 1,397
Generation	625	1,626	172
ComEd	220	105	300
PECO	333	347	352
BGE	13	13	98[(a)]

(a) Dividends on common stock for $85 million were paid to Constellation for the year ended December 31, 2011.

Revised Dividend Policy

On February 6, 2013, the Exelon board of directors approved a revised dividend policy which contemplates a regular $0.31 per share quarterly dividend on Exelon s common stock payable beginning in the second quarter of 2013 (or $1.24 per share on an annualized basis), subject to quarterly declarations by the Exelon Board of Directors.

Second Quarter 2013 Dividend

On April 23, 2013, the Exelon board of directors declared a regular quarterly dividend, paid on June 10, 2013 of $0.310 per share on Exelon s common stock.

Third Quarter 2013 Dividend

On July 23, 2013, the Exelon board of directors declared a regular quarterly dividend, paid on September 10, 2013 of $0.310 per share on Exelon s common stock.

Fourth Quarter 2013 Dividend

On October 22, 2013, the Exelon board of directors declared a regular quarterly dividend, paid on December 10, 2013 of $0.310 per share on Exelon s common stock

First Quarter 2014 Dividend

On January 28, 2014, the Exelon Board of Directors declared a first quarter 2014 regular quarterly dividend of $0.31 per share on Exelon s common stock payable on March 10, 2014, to shareholders of record of Exelon at the end of the day on February 14, 2014.

Short-Term Borrowings. Short-term borrowings incurred (repaid) during 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Generation	$ 13	$ (52)	$
ComEd	184		
BGE	135		
Other [(a)]		(140)	161

Exelon	$ 332	$ (192)	$ 161

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

Retirement of Long-Term Debt to Financing Affiliates. There were no retirements of long-term debt to financing affiliates during 2013, 2012 and 2011 by the Registrants.

Contributions from Parent/Member. Contributions from Parent/Member (Exelon) during 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Generation	$ 26	$ 48	$ 30
ComEd [(a)]	176	11	11
PECO	27	9	18
BGE		66	

(a) In 2013, represents indemnification from Exelon in relation to the like-kind exchange transaction.

Other. Other significant financing activities for Exelon for 2013, 2012 and 2011 were as follows:

Exelon received proceeds from employee stock plans of $47 million, $72 million and $38 million during 2013, 2012 and 2011, 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 $8.4 billion in aggregate total commitments of which $6.6 billion was available as of December 31, 2013, and of which no financial institution has more than 8% of the aggregate commitments for Exelon, Generation, ComEd, PECO and BGE. The Registrants had access to the commercial paper market during 2013 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 for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow 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, 2013, it would have been required to provide incremental collateral of $2.0 billion 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, which is well within its current available credit facility capacities of $4.3 billion. If ComEd lost its investment grade credit ratings as of December 31, 2013, it would have been required to provide incremental collateral of $6 million, which is well within its current available credit facility capacity of $816 million, which takes into account commercial paper borrowings as of December 31, 2013. If PECO lost its investment grade credit rating as of December 31, 2013 it would not be required to provide collateral pursuant to PJM s credit policy and could have been required to provide collateral of $42 million related to its natural gas procurement contracts, which, in the aggregate, are well within PECO s current available credit facility capacity of $599 million. If BGE lost its investment grade credit rating as of December 31, 2013, it would have been required to provide collateral of $2 million pursuant to PJM s credit policy and could have been required to provide collateral of $85 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE s current available credit facility capacity of $465 million.

Exelon Credit Facilities

See Note 13 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, 2013, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE
Long-term debt	44%	30%	42%	40%	42%
Long-term debt to affiliates [(a)]	2%	8%	2%	4%	5%
Common equity	53%		55%	56%	49%
Member s equity		62%			
Preference Stock					4%
Commercial paper and notes payable	1%		1%		

(a) Includes approximately $648 million, $206 million, $184 million and $258 million owed to unconsolidated affiliates of Exelon, ComEd, PECO and BGE respectively. These special purpose entities were created for the sole purposes of issuing mandatorily redeemable trust preferred securities of ComEd, PECO and BGE. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information regarding the authoritative guidance for VIEs.

Intercompany Money Pool. To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participants during the year ended December 31, 2013, in addition to the net contribution or borrowing as of December 31, 2013, are presented in the following table:

	Maximum Contributed	Maximum Borrowed	December 31, 2013 Contributed (Borrowed)
Generation	$ 159	$ 435	$ 44
PECO	304		
BSC		287	(223)
Exelon Corporate	237		179

Investments in Nuclear Decommissioning Trust Funds. Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation s nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation s NDT fund investment policy. Generation s investment policy establishes limits on the concentration of holdings in any one company and also in any one industry. See Note 15 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC s minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements. The Registrants maintain a combined shelf registration statement unlimited in amount, with the SEC. The ability of each Registrant to sell securities off the 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, PECO and BGE of long-term debt or equity securities requires the prior authorization of the ICC, PAPUC and MDPSC, respectively. ComEd, PECO and BGE 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. On March 1, 2013, ComEd received $470 million in long-term debt new money authority from the ICC and on February 27, 2012, ComEd received $1.3 billion in long-term debt refinancing authority from the ICC.

As of December 31, 2013, ComEd had $1.3 billion available in long-term debt refinancing authority and $218 million available in new money long-term debt financing authority from the ICC. During the fourth quarter of 2013, ComEd requested and received $1 billion in new money financing authority from the ICC. The authority is effective on January 1, 2014 and expires January 1, 2017. As of December 31, 2013, PECO had $1.4 billion available in long-term debt financing authority from the PAPUC. As of December 31, 2013, BGE had $850 million available in long-term financing authority from MDPSC.

FERC has financing jurisdiction over ComEd s, PECO s and BGE s short-term financings and all of Generation s financings. As of December 31, 2013, ComEd, PECO had BGE had short-term financing authority from FERC, which expires on December 31, 2015, of $2.5 billion, $2.5 billion and $700 million, respectively. Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority. See Note 3 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. BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE s equity ratio would be below 48% as calculated pursuant to the MDPSC s ratemaking precedents or (b) BGE s senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE s preference stock have not been paid. At December 31, 2013, Exelon had retained earnings of $10,358 million, including Generation s undistributed earnings of $3,613 million, ComEd s retained earnings of $750 million consisting of retained earnings appropriated for future dividends of $2,389 million partially offset by $1,639 million of unappropriated retained deficit, PECO s retained earnings of $649 million and BGE s retained earnings $1,005 million. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Contractual Obligations

The following tables summarize the Registrants future estimated cash payments as of December 31, 2013 under existing contractual obligations, including payments due by period. See Note 22 of the Combined Notes to Consolidated Financial Statements for information regarding the Registrants commercial and other commitments, representing commitments potentially triggered by future events.

Exelon

		Payment due within				
	Total	2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt [a]	$ 19,367	$ 1,424	$ 2,953	$ 2,731	$ 12,259	$
Interest payments on long-term debt [b]	12,845	925	1,692	1,396	8,832	
Liability and interest for uncertain tax positions [c]	1,255					1,255
Capital leases	41	4	8	10	19	
Operating leases [d]	826	103	180	145	398	
Purchase power obligations [e]	3,046	1,378	852	367	449	
Fuel purchase agreements [f]	9,606	1,520	2,622	1,967	3,497	
Electric supply procurement [f]	1,880	1,062	678	140		
AEC purchase commitments [f]	6	1	2	2	1	
Curtailment services commitments [f]	132	45	74	13		
Long-term renewable energy and REC commitments [g]	1,589	72	150	160	1,207	
PJM regional transmission expansion commitments [h]	1,019	208	597	214		
Spent nuclear fuel obligation	1,021				1,021	
Pension minimum funding requirement [i]	1,223	264	444	426	89	
Total contractual obligations	$ 53,856	$ 7,006	$ 10,252	$ 7,571	$ 27,772	$ 1,255

(a) Includes $648 million due after 2016 to ComEd, PECO and BGE financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 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, 2013. Includes estimated interest payments due to ComEd, PECO and BGE financing trusts.

(c) As of December 31, 2013, Exelon s liability for uncertain tax positions and related interest payable was $906 million and $349 million, respectively. Exelon was unable to reasonably estimate the timing of liability and interest payments and receipts in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. Exelon has other unrecognized tax positions that were not recorded on the Consolidated Balance Sheet in accordance with authoritative guidance. See Note 14 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 including those that are accounted for as operating leases. Amounts presented represent Generation s expected payments under these arrangements at December 31, 2013, including those related to CENG. Expected payments include certain fixed capacity charges which may be reduced based 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 3 and 22 of the Combined Notes to Consolidated Financial Statements.

(f) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs and curtailment services. See Note 22 of the Combined Notes to Consolidated Financial Statements for electric and gas purchase commitments.

(g) ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the

ICC s December 19, 2012 order, ComEd s commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC s December 18, 2013 order approved the reduction of ComEd s commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

(h) Under their operating agreements with PJM, ComEd, PECO and BGE are committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd s, PECO s and BGE s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

(i) 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. For Exelon s largest qualified pension plan, the projected contributions reflect a funding strategy of contributing the greater of $250 million or the minimum amounts under ERISA 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 2019 are not included. See Note 16 of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

Generation

		Payment due within				
	Total	2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt	$ 7,519	$ 557	$ 628	$ 701	$ 5,633	$
Interest payments on long-term debt [(a)]	5,362	368	693	625	3,676	
Liability and interest for uncertain tax benefits [(b)]	264					264
Capital leases	33	4	8	10	11	
Operating leases [(c)]	571	49	98	88	336	
Purchase power obligations [(d)]	3,046	1,378	852	367	449	
Fuel purchase agreements [(e)]	8,490	1,212	2,296	1,807	3,175	
Spent nuclear fuel obligation	1,021				1,021	
Total contractual obligations	$ 26,306	$ 3,568	$ 4,575	$ 3,598	$ 14,301	$ 264

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 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, 2013.

(b) As of December 31, 2013, Generation s liability for uncertain tax positions and related interest payable was $227 million and $37 million, respectively. Generation 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.

(c) Excludes PPAs and other capacity contracts that are accounted for as operating leases. These amounts are included within purchase power obligations.

(d) Purchase power obligations include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented represent Generation s expected payments under these arrangements at December 31, 2013. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. See Note 22 of the Combined Notes to Consolidated Financial Statements.

(e) See Note 22 of the Combined Notes to Consolidated Financial Statements for further information regarding fuel purchase agreements.

ComEd

			Payment due within			
	Total	2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt [(a)]	$ 5,892	$ 617	$ 925	$ 1,265	$ 3,085	$
Interest payments on long-term debt [(b)]	3,704	274	515	393	2,522	
Liability and interest for uncertain tax positions [(c)]	498					498
Capital leases	8				8	
Operating leases	47	13	22	9	3	
Electric supply procurement	736	323	273	140		
Long-term renewable energy and associated REC commitments [(d)]	1,589	72	150	160	1,207	
PJM regional transmission expansion commitments [(e)]	486	134	350	2		
Total contractual obligations	$ 12,960	$ 1,433	$ 2,235	$ 1,969	$ 6,825	$ 498

(a) Includes $206 million due after 2017 to a ComEd financing trust.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 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, 2013. Includes estimated interest payments due to the ComEd financing trust.

(c) As of December 31, 2013, ComEd s liability for uncertain tax positions and related interest payable was $324 million and $174 million, respectively. ComEd 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.

(d) ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC s December 19, 2012 order, ComEd s commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC s December 18, 2013 order approved the reduction of ComEd s commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

(e) Under its operating agreement with PJM, ComEd is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

PECO

			Payment due within			
	Total	2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt [(a)]	$ 2,384	$ 250	$ 300	$ 500	$ 1,334	$
Interest payments on long-term debt [(b)]	1,505	104	189	160	1,052	
Operating leases	25	13	6	6		
Fuel purchase agreements [(c)]	507	179	210	52	66	
Electric supply procurement [(c)]	681	590	91			
AEC purchase commitments [(c)]	14	2	4	4	4	
PJM regional transmission expansion commitments [(d)]	133	32	69	32		
Total contractual obligations	$ 5,249	$ 1,170	$ 869	$ 754	$ 2,456	$

(a) Includes $184 million due after 2017 to PECO financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

(d) Under its operating agreement with PJM, PECO is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PECO s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

BGE

		Payment due within				
	Total	2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt [a]	$ 2,273	$	$ 300	$ 265	$ 1,708	$
Interest payments on long-term debt [b]	1,608	112	220	162	1,114	
Operating leases	61	12	20	15	14	
Fuel purchase agreements [c]	609	129	116	108	256	
Electric supply procurement [c]	1,256	783	473			
Curtailment services commitments [c]	132	45	74	13		
PJM regional transmission expansion commitments [d]	400	42	178	180		
Total contractual obligations	$ 6,339	$ 1,123	$ 1,381	$ 743	$ 3,092	$

(a) Includes $258 million due after 2017 to the BGE financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and curtailment services. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.
(d) Under its operating agreement with PJM, BGE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent BGE s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

See Note 22 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 13 of the Combined Notes to Consolidated Financial Statements.

long-term debt, see Note 13 of the Combined Notes to Consolidated Financial Statements.

liabilities related to uncertain tax positions, see Note 14 of the Combined Notes to Consolidated Financial Statements.

capital lease obligations, see Note 13 of the Combined Notes to Consolidated Financial Statements.

operating leases, energy commitments, fuel purchase agreements, construction commitments and rate relief commitments, see Note 22 of the Combined Notes to Consolidated Financial Statements.

the nuclear decommissioning and SNF obligations, see Notes 15 and 22 of the Combined Notes to Consolidated Financial Statements.

regulatory commitments, see Note 3 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 22 of the Combined Notes to Consolidated Financial Statements.

new accounting pronouncements, see Note 1 of the Combined Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

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, PECO s and BGE s retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as 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 will occur during 2014 through 2016.

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, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015 and 2016, 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 economic hedges and certain non-derivative contracts including sales to ComEd, PECO and BGE 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 entire non-trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on December 31, 2013, market conditions and hedged position would be a decrease in pre-tax net income of approximately $30 million, $520 million and $820 million, respectively, for 2014, 2015 and 2016. 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 with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon s RMC. The proprietary 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 8,762 GWh, 12,958 GWh, and 5,742 GWh for the years ended December 31, 2013, 2012 and 2011 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, 2013, resulted in pre-tax losses of $8 million due to net mark-to-market losses of $39 million and realized gains of $31 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $1.0 million of exposure during the year. Generation has not segregated proprietary trading activity within the following discussion 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, 2013 of $7,433 million.

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 60% of Generation s uranium concentrate requirements from 2014 through 2018 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 22 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 would be entitled to receive full cost recovery in rates. The change in fair value each period was recorded by ComEd with an offset to a regulatory asset or liability. This financial swap contract between Generation and ComEd expired on May 31, 2013. All realized impacts have been included in Generation s and ComEd s results of operations.

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC s Order on December 19, 2012, ComEd s commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC s December 18, 2013 order approved the reduction of ComEd s commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Notes 3 and 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3 of the Combined Notes to the Consolidated Financial Statements. 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 and as a result, are accounted for on an accrual basis of accounting. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no 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 12 of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE s MDPSC-approved SOS program. BGE s full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance and as a result, are accounted for on an accrual basis of accounting. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE s financial position. However, under BGE s market-based rates incentive mechanism, BGE s actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE s actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 12 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, and ComEd s mark-to-market net asset or liability balance sheet position from January 1, 2012, to December 31, 2013. 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 cash flow hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 12 of the Combined Notes to the Consolidated Financial Statements for more information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2013, and December 31, 2012.

	Generation	ComEd	Intercompany Eliminations (b)	Exelon
Total mark-to-market energy contract net assets (liabilities) at January 1, 2012 (a)	$ 1,648	$ (800)	$	$ 848
Contracts acquired at merger date (c)	140			140
Total change in fair value during 2012 of contracts recorded in result of operations	(159)		7	(152)
Reclassification to realized at settlement of contracts recorded in results of operations	775			775
Ineffective portion recognized in income (d)	(5)			(5)
Reclassification to realized at settlement from accumulated OCI (e)	(1,368)		621	(747)
Effective portion of changes in fair value recorded in OCI (f)	719		(146)	573
Changes in fair value energy derivatives (g)		507	(482)	25
Changes in allocated collateral	(89)			(89)
Changes in net option premium paid/(received)	114			114
Option premium amortization (h)	(160)			(160)
Intercompany elimination of existing derivative contracts with Constellation	(103)			(103)
Other balance sheet reclassifications	(7)			(7)
Total mark-to-market energy contract net assets (liabilities) at December 31, 2012 (a)	$ 1,505	$ (293)	$	$ 1,212
Total change in fair value during 2013 of contracts recorded in result of operations	444		(6)	438
Reclassification to realized at settlement of contracts recorded in results of operations	21		13	34
Reclassification to realized at settlement from accumulated OCI (e)	(683)		219	(464)
Changes in fair value energy derivatives (g)		100	(226)	(126)
Changes in allocated collateral	(175)			(175)
Changes in net option premium paid/(received)	36			36
Option premium amortization (h)	(104)			(104)
Other balance sheet reclassifications	4			4
Total mark-to-market energy contract net assets (liabilities) at December 31, 2013 (a) (i)	$ 1,048	$ (193)	$	$ 855

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Amounts related to the five-year financial swap between Generation and ComEd.
(c) For Generation, includes $660 million of collateral paid to counterparties, offset by $520 million of unrealized losses on commodity derivative positions.

(d) For Generation, reflects $5 million of changes in cash flow hedge ineffectiveness.
(e) For Generation, includes $219 million and $621 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, 2013 and 2012, respectively.
(f) For Generation, includes $146 million of gains related to the changes in fair value of the five-year financial swap with ComEd for the year ended 2012. Effective prior to the merger with Constellation, the five-year financial swap between Generation and ComEd was de-designated as a cash flow hedge. As a result, all changes in fair value for the year ended December 31, 2013 were recorded to operating revenues and eliminated in consolidation.
(g) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2013 and 2012, ComEd recorded a regulatory liability of $193 million and $293 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of December 31, 2013 and 2012, this includes $11 million of decreases and $98 million of increases in fair value, respectively, and $215 million and $566 million, respectively, for reclassifications from regulatory assets to recognize cost in purchase power expense due to settlements of ComEd s five-year financial swap with Generation. As of December 31, 2013 and 2012 ComEd also recorded $126 million and $34 million, respectively, of increases in fair value, and $7 million and $5 million, respectively, of realized losses due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.
(h) Includes $104 million and $160 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, 2013 and 2012, respectively.
(i) Includes the ending balance related to interest rate derivative contracts and foreign exchange currency swaps to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars.

Fair Values

The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants commodity contract net assets (liabilities) net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 11 Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2014	**2015**	**2016**	**2017**	**2018**	**2019 and Beyond**	**Total Fair Value**
Normal Operations, Commodity derivative contracts [(a)(b)]:							
Actively quoted prices (Level 1)	$ (30)	$ (26)	$ 17	$ (4)	$ (2)	$	$ (45)
Prices provided by external sources (Level 2)	444	143	39			1	627
Prices based on model or other valuation methods (Level 3) [(c)]	155	151	71	25	(22)	(108)	272
Total	$ 569	$ 268	$ 127	$ 21	$ (24)	$ (107)	$ 854

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $144 million at December 31, 2013.
(c) Includes ComEd s net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts [(a)(b)]*:*							
Actively quoted prices (Level 1)	$ (30)	$ (26)	$ 17	$ (4)	$ (2)	$	$ (45)
Prices provided by external sources (Level 2)	444	143	39			1	627
Prices based on model or other valuation methods (Level 3)	172	170	89	43	(4)	(5)	465
Total	$ 586	$ 287	$ 145	$ 39	$ (6)	$ (4)	$ 1,047

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $144 million at December 31, 2013.

ComEd

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Fair Value
Prices based on model or other valuation methods (Level 3) [(a)]	$ (17)	$ (19)	$ (18)	$ (18)	$ (18)	$ (103)	$ (193)

(a) Represents ComEd s net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

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

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 12 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, 2013. 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, NYMEX, ICE, and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $38 million, $38 million and $27 million, respectively. See Note 25 of the Combined Notes to Consolidated Financial Statements for further information.

Rating as of December 31, 2013	Total Exposure Before Credit Collateral	Credit Collateral (a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,621	$ 172	$ 1,449	1	$ 491
Non-investment grade	27	9	18		
No external ratings					
Internally rated investment grade	416	1	415	1	226
Internally rated non-investment grade	30	2	28		
Total	$ 2,094	$ 184	$ 1,910	2	$ 717

Rating as of December 31, 2013	Maturity of Credit Risk Exposure			
	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 1,146	$ 340	$ 135	$ 1,621
Non-investment grade	23	4		27
No external ratings				
Internally rated investment grade	272	138	6	416
Internally rated non-investment grade	30			30
Total	$ 1,471	$ 482	$ 141	$ 2,094

Net Credit Exposure by Type of Counterparty	As of December 31, 2013
Financial Institutions	$ 256
Investor-owned utilities, marketers and power producers	684
Energy cooperatives and municipalities	907
Other	63
Total	$ 1,910

(a) As of December 31, 2013, credit collateral held from counterparties where Generation had credit exposure included $155 million of cash and $29 million of letters of credit.

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. See Note 1 of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. 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, 2013. See Note 3 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 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. ComEd s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. As of December 31, 2013, 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, 2013.

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, 2013, PECO had no net credit exposure with suppliers.

PECO does not obtain cash collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2013, PECO had credit exposure of $9 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE

Credit risk for BGE is managed by credit and collection policies, which are consistent with state regulatory requirements. BGE is currently obligated to provide service to all electric customers within its franchised territory. BGE records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. BGE will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. See Note 1 of the Combined Notes to Consolidated Financial Statements for uncollectible accounts policy. MDPSC regulations prohibit BGE from terminating service to residential customers due to nonpayment from November 1 through March 31 if the forecasted temperature is 32 degrees or below for the subsequent 72 hour period. BGE is also prohibited by the Maryland Public Utilities Article and MDPSC regulations from terminating service to residential customers due to nonpayment if the forecasted temperature is 95 degrees or above for the subsequent 72 hour period. BGE did not have any customers representing over 10% of its revenues as of December 31, 2013.

BGE s full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier s performance assurance requirements, allow a supplier, or its guarantor, 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, subject to an unsecured credit cap. 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. The seller s credit exposure is calculated each business day. As of December 31, 2013, BGE had no net credit exposure with suppliers.

BGE s regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE s recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers demands, which are not covered by the gas cost adjustment clause. At December 31, 2013, BGE had credit exposure of $14 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Collateral (Exelon, Generation, ComEd, PECO and BGE)

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, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount

of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 12 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. See Note 13 of the Combined Notes to Consolidated Financial Statements for additional information.

As of December 31, 2013, Generation had cash collateral of $72 million posted and cash collateral held of $206 million for counterparties with derivative positions, of which $144 million in net cash collateral deposits were offset against mark-to-market assets and liabilities. As of December 31, 2013, $10 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives. As of December 31, 2012, Generation had cash collateral held of $499 million and cash collateral posted of $527 million for counterparties with derivative positions, of which $31 million in net cash collateral deposits were offset against mark-to-market assets and liabilities. As of December 31, 2012, $3 million of cash collateral received was not offset against net mark-to-market assets and liabilities because it was not associated with energy-related derivatives. See Note 22 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of December 31, 2013, ComEd held immaterial amounts 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 for both annual and long-term renewable energy contracts. See Notes 3 and 12 of the Combined Notes to Consolidated Financial Statements for further information.

PECO

As of December 31, 2013, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 12 of the Combined Notes to Consolidated Financial Statements for further information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of December 31, 2013, BGE was not required to post collateral under its natural gas procurement contracts, nor was it holding collateral under its electric supply and natural gas procurement contracts. See Note 12 of the Combined Notes to Consolidated Financial Statements for further information.

RTOs and ISOs (Exelon, Generation, ComEd, PECO and BGE)

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

Exchange Traded Transactions (Exelon and Generation)

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

Long-Term Leases (Exelon)

Exelon s consolidated balance sheet, as of December 31, 2013, included a $698 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 $1,465 million, less unearned income of $767 million. 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 for a third-party to bid on a service contract 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. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract 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. Management regularly evaluates the creditworthiness of Exelon s counterparties to these long-term leases. Exelon monitors the continuing credit quality of the credit enhancement party.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and, if the review indicates a fair value below the carrying value and the decline is determined to be other than temporary, must record an impairment charge in the period the estimate changed. Based on the review performed in the second quarter of 2013, the estimated residual value of one of Exelon s direct financing leases experienced an other than temporary decline resulting in a $14 million pre-tax impairment charge in the second quarter of 2013. See Note 8 of the Combined Notes to Consolidated Financial Statements for further information. Through December 31, 2013, no events have occurred that would require Exelon to review the estimated residual values of its direct financing lease investments subsequent to the review performed in the second quarter of 2013.

Interest-Rate Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the

Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2013, Exelon had $1,425 million of notional amounts of fixed-to-floating hedges outstanding and $190 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximate $5 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2013.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation s nuclear plants. As of December 31, 2013, Generation s decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation s NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $482 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 ITEM 7. 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.

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Generation

General

Generation operates in six segments: Mid-Atlantic, Midwest, New England, New York, ERCOT, and Other Regions in Generation. The operation of all six segments consists of owned contracted and investments in electric generating facilities, and wholesale and retail customer supply of electric and natural gas products and services, including renewable energy products, risk management services and investments in natural gas exploration and production activities. These segments are discussed in further detail in ITEM 1. BUSINESS Generation of this Form 10-K.

Executive Overview

A discussion of items pertinent to Generation s executive overview is set forth under ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Exelon Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared To Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of Generation s results of operations for 2013 compared to 2012 and 2012 compared to 2011 is set forth under Results of Operations Generation in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

Generation s business is capital intensive and requires considerable capital resources. Generation s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, participation in the intercompany money pool or capital contributions from Exelon. Generation s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has access to credit facilities in the aggregate of $5.6 billion that Generation currently utilizes to support its commercial paper program and to issue letters of credit.

See the EXELON CORPORATION Liquidity and Capital Resources and Note 13 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund Generation s capital requirements, including construction, retirement of debt, the payment of distributions to Exelon, contributions to Exelon s pension plans and investments in new and existing ventures. Future acquisitions could require external financing or borrowings or capital contributions from Exelon.

Cash Flows from Operating Activities

A discussion of items pertinent to Generation s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to Generation s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Generation s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Generation is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Generation s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO Critical Accounting Policies and Estimates above for a discussion of Generation s critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Generation

Generation is exposed to market risks associated with commodity price, credit, interest rates and equity price. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ComEd

General

ComEd operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in northern Illinois, including the City of Chicago. This segment is discussed in further detail in ITEM 1. BUSINESS ComEd of this Form 10-K.

Executive Overview

A discussion of items pertinent to ComEd s executive overview is set forth under EXELON CORPORATION Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of ComEd s results of operations for 2013 compared to 2012 and for 2012 compared to 2011 is set forth under Results of Operations ComEd in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

ComEd s business is capital intensive and requires considerable capital resources. ComEd s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ComEd s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2013, ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion. See the Credit Matters section of Liquidity and Capital Resources for additional discussion.

See the EXELON CORPORATION Liquidity and Capital Resources and Note 13 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund ComEd s capital requirements, including construction, retirement of debt, and contributions to Exelon s pension plans. Additionally, ComEd operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ComEd s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to ComEd s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to ComEd s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ComEd is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ComEd s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO Critical Accounting Policies and Estimates above for a discussion of ComEd s critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ComEd

ComEd is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PECO

General

PECO operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution service in Pennsylvania in the counties surrounding the City of Philadelphia. This segment is discussed in further detail in ITEM 1. BUSINESS PECO of this Form 10-K.

Executive Overview

A discussion of items pertinent to PECO s executive overview is set forth under EXELON CORPORATION Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of PECO s results of operations for 2013 compared to 2012 and for 2012 compared to 2011 is set forth under Results of Operations PECO in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

PECO s business is capital intensive and requires considerable capital resources. PECO s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or participation in the intercompany money pool. PECO s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At December 31, 2013, PECO had access to a revolving credit facility with aggregate bank commitments of $600 million. See the Credit Matters section of Liquidity and Capital Resources for additional discussion.

Capital resources are used primarily to fund PECO s capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon s pension plans. Additionally, PECO operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PECO s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to PECO s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to PECO s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PECO is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PECO s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO Critical Accounting Policies and Estimates above for a discussion of PECO s critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PECO

PECO is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BGE

General

BGE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution service in central Maryland, including the City of Baltimore. This segment is discussed in further detail in ITEM 1. BUSINESS BGE of this Form 10-K.

Executive Overview

A discussion of items pertinent to BGE s executive overview is set forth under EXELON CORPORATION Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of BGE s results of operations for 2013 compared to 2012 and for 2012 compared to 2011 is set forth under Results of Operations BGE in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

BGE s business is capital intensive and requires considerable capital resources. BGE s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. BGE s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where BGE no longer has access to the capital markets at reasonable terms, BGE has access to a revolving credit facility. At December 31, 2013, BGE had access to a revolving credit facility with aggregate bank commitments of $600 million. See the Credit Matters section of Liquidity and Capital Resources for additional discussion.

Capital resources are used primarily to fund BGE s capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon s pension plans. Additionally, BGE operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to BGE s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to BGE s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to BGE s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to BGE is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of BGE s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd, PECO and BGE Critical Accounting Policies and Estimates above for a discussion of BGE s critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BGE

BGE is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

ITEM 8. 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, as such term is defined in Exchange Act Rule 13a-15(f). 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.

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, 2013. In making this assessment, management used the criteria in *Internal Control Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon s management concluded that, as of December 31, 2013, Exelon s internal control over financial reporting was effective.

The effectiveness of the Exelon s internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management s Report on Internal Control Over Financial Reporting

The management of Exelon Generation Company, LLC (Generation) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). 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.

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.

Generation s management conducted an assessment of the effectiveness of Generation s internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Generation s management concluded that, as of December 31, 2013, Generation s internal control over financial reporting was effective.

The effectiveness of the Generation s internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management s Report on Internal Control Over Financial Reporting

The management of Commonwealth Edison Company (ComEd) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). 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.

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.

ComEd s management conducted an assessment of the effectiveness of ComEd s internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ComEd s management concluded that, as of December 31, 2013, ComEd s internal control over financial reporting was effective.

The effectiveness of the ComEd s internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management s Report on Internal Control Over Financial Reporting

The management of PECO Energy Company (PECO) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). 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.

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.

PECO s management conducted an assessment of the effectiveness of PECO s internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PECO s management concluded that, as of December 31, 2013, PECO s internal control over financial reporting was effective.

The effectiveness of the PECO s internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management s Report on Internal Control Over Financial Reporting

The management of Baltimore Gas and Electric Company (BGE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). 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.

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.

BGE s management conducted an assessment of the effectiveness of BGE s internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, BGE s management concluded that, as of December 31, 2013, BGE s internal control over financial reporting was effective.

The effectiveness of BGE s internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Exelon Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Corporation (the Company) and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 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 index appearing under item 15(a)(2) 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, 2013, based on criteria established in *Internal Control Integrated Framework (1992)* 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 the accompanying 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.

/s/ PricewaterhouseCoopers LLP

Chicago, Illinois

February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Exelon Generation Company, LLC:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Generation Company, LLC (the Company) and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents 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, 2013, based on criteria established in *Internal Control Integrated Framework (1992)* 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 schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, 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.

/s/ PricewaterhouseCoopers LLP

Baltimore, Maryland

February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Commonwealth Edison Company (the Company) and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents 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, 2013, based on criteria established in *Internal Control Integrated Framework (1992)* 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 schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, 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.

/s/ PricewaterhouseCoopers LLP

Chicago, Illinois

February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of PECO Energy Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of PECO Energy Company (the Company) and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents 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, 2013, based on criteria established in *Internal Control Integrated Framework (1992)* 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 schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, 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.

/s/ PricewaterhouseCoopers LLP

Philadelphia, Pennsylvania

February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Baltimore Gas and Electric Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company (the Company) and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents 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, 2013, based on criteria established in *Internal Control Integrated Framework (1992)* 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 schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our audits (which was an integrated audit in 2012). 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.

/s/ PricewaterhouseCoopers LLP

Baltimore, Maryland

February 13, 2014

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

	For the Years Ended December 31,		
(In millions, except per share data)	**2013**	**2012**	**2011**
Operating revenues	$ 24,888	$ 23,489	$ 19,063
Operating expenses			
Purchased power and fuel	9,468	9,121	7,130
Purchased power and fuel from affiliates	1,256	1,036	137
Operating and maintenance	7,270	7,961	5,184
Depreciation and amortization	2,153	1,881	1,347
Taxes other than income	1,095	1,019	785
Total operating expenses	21,242	21,018	14,583
Equity in earnings (losses) of unconsolidated affiliates	10	(91)	(1)
Operating income	3,656	2,380	4,479
Other income and (deductions)			
Interest expense, net	(1,315)	(891)	(701)
Interest expense to affiliates, net	(41)	(37)	(25)
Other, net	473	346	203
Total other income and (deductions)	(883)	(582)	(523)
Income before income taxes	2,773	1,798	3,956
Income taxes	1,044	627	1,457
Net income	1,729	1,171	2,499
Net income attributable to non-controlling interests, preferred security dividends and preference stock dividends	10	11	4
Net income attributable to common shareholders	1,719	1,160	2,495
Comprehensive income (loss), net of income taxes			
Net income	1,729	1,171	2,499
Other comprehensive income (loss)			
Pension and non-pension postretirement benefit plans:			
Prior service cost (benefit) reclassified to periodic costs, net of taxes of $0, $1 and $(4), respectively		1	(5)
Actuarial loss reclassified to periodic cost, net of taxes of $133, $110 and $93, respectively	208	168	136
Transition obligation reclassified to periodic cost, net of taxes of $0, $2 and $2, respectively		2	4
Pension and non-pension postretirement benefit plan valuation adjustment, net of taxes of $430, $(237) and $(171), respectively	669	(371)	(250)
Unrealized gain (loss) on cash flow hedges, net of taxes of $(166), $(68) and $39, respectively	(248)	(120)	88
Unrealized gain (loss) on marketable securities, net of taxes of $0, $(1) and $0, respectively	2	2	
Unrealized gain (loss) on equity investments, net of taxes of $71, $1 and $0, respectively	106	1	
Unrealized gain (loss) on foreign currency translation, net of taxes of $0, $0 and $0, respectively	(10)		
Other comprehensive income (loss)	727	(317)	(27)
Comprehensive income	$ 2,456	$ 854	$ 2,472

Average shares of common stock outstanding:			
Basic	856	816	663
Diluted	860	819	665
Earnings per average common share:			
Basic	$ 2.01	$ 1.42	$ 3.76
Diluted	$ 2.00	$ 1.42	$ 3.75
Dividends per common share	$ 1.46	$ 2.10	$ 2.10

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	2013	For the Years Ended December 31, 2012	2011
Cash flows from operating activities			
Net income	$ 1,729	$ 1,171	$ 2,499
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	3,779	4,079	2,316
Loss on sale of three Maryland generating stations		272	
Deferred income taxes and amortization of investment tax credits	119	615	1,457
Net fair value changes related to derivatives	(445)	(604)	291
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(170)	(157)	14
Other non-cash operating activities	876	1,383	770
Changes in assets and liabilities:			
Accounts receivable	(97)	243	57
Inventories	(100)	26	(58)
Accounts payable, accrued expenses and other current liabilities	(90)	(632)	(254)
Option premiums paid, net	(36)	(114)	(3)
Counterparty collateral received (posted), net	215	135	(344)
Income taxes	883	544	492
Pension and non-pension postretirement benefit contributions	(422)	(462)	(2,360)
Other assets and liabilities	102	(368)	(24)
Net cash flows provided by operating activities	6,343	6,131	4,853
Cash flows from investing activities			
Capital expenditures	(5,395)	(5,789)	(4,042)
Proceeds from nuclear decommissioning trust fund sales	4,217	7,265	6,139
Investment in nuclear decommissioning trust funds	(4,450)	(7,483)	(6,332)
Cash and restricted cash acquired from Constellation		964	
Acquisitions of long lived assets		(21)	(387)
Proceeds from sale of long-lived assets	32	371	
Proceeds from sales of investments	22	28	6
Purchases of investments	(4)	(13)	(4)
Change in restricted cash	(43)	(34)	(3)
Distribution from CENG	115		
Other investing activities	112	136	20
Net cash flows used in investing activities	(5,394)	(4,576)	(4,603)
Cash flows from financing activities			
Payment of accounts receivable agreement	(210)	(15)	
Changes in short-term debt	332	(197)	161
Issuance of long-term debt	2,055	2,027	1,199
Retirement of long-term debt	(1,589)	(1,145)	(789)
Redemption of preferred securities	(93)		
Dividends paid on common stock	(1,249)	(1,716)	(1,393)
Proceeds from employee stock plans	47	72	38
Other financing activities	(119)	(111)	(62)
Net cash flows used in financing activities	(826)	(1,085)	(846)
Increase (decrease) in cash and cash equivalents	123	470	(596)

Cash and cash equivalents at beginning of period	1,486	1,016	1,612
Cash and cash equivalents at end of period	$ 1,609	$ 1,486	$ 1,016

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,547	$ 1,411
Cash and cash equivalents of variable interest entities	62	75
Restricted cash and investments	87	86
Restricted cash and investments of variable interest entities	80	47
Accounts receivable, net		
Customer ($0 and $289 gross accounts receivables pledged as collateral as of December 31, 2013 and December 31, 2012, respectively)	2,721	2,795
Other	1,175	1,141
Accounts receivable, net, of variable interest entities	260	292
Mark-to-market derivative assets	727	938
Unamortized energy contract assets	374	886
Inventories, net		
Fossil fuel	276	246
Materials and supplies	829	768
Deferred income taxes	573	131
Regulatory assets	760	764
Other	666	560
Total current assets	10,137	10,140
Property, plant and equipment, net	47,330	45,186
Deferred debits and other assets		
Regulatory assets	5,910	6,497
Nuclear decommissioning trust funds	8,071	7,248
Investments	1,165	1,184
Investments in affiliates	22	22
Investment in CENG	1,925	1,849
Goodwill	2,625	2,625
Mark-to-market derivative assets	607	937
Unamortized energy contract assets	710	1,073
Pledged assets for Zion Station decommissioning	458	614
Deferred income taxes		58
Other	964	1,128
Total deferred debits and other assets	22,457	23,235
Total assets	$ 79,924	$ 78,561

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	2012
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 341	$
Short-term notes payable accounts receivable agreement		210
Long-term debt due within one year	1,424	975
Long-term debt due within one year of variable interest entities	85	72
Accounts payable	2,314	2,378
Accounts payable of variable interest entities	170	202
Payables to affiliates	116	112
Mark-to-market derivative liabilities	159	352
Unamortized energy contract liabilities	261	455
Accrued expenses	1,633	1,796
Deferred income taxes	40	58
Regulatory liabilities	327	368
Other	858	813
Total current liabilities	7,728	7,791
Long-term debt	17,325	17,190
Long-term debt to financing trusts	648	648
Long-term debt of variable interest entities	298	508
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	12,905	11,551
Asset retirement obligations	5,194	5,074
Pension obligations	1,876	3,428
Non-pension postretirement benefit obligations	2,190	2,662
Spent nuclear fuel obligation	1,021	1,020
Regulatory liabilities	4,388	3,981
Mark-to-market derivative liabilities	300	281
Unamortized energy contract liabilities	266	528
Payable for Zion Station decommissioning	305	432
Other	2,540	1,650
Total deferred credits and other liabilities	30,985	30,607
Total liabilities	56,984	56,744
Commitments and contingencies		
Preferred securities of subsidiary		87
Shareholders equity		
Common stock (No par value, 2,000 shares authorized, 857 and 855 shares outstanding at December 31, 2013 and 2012, respectively)	16,741	16,632
Treasury stock, at cost (35 shares held at December 31, 2013 and 2012, respectively)	(2,327)	(2,327)
Retained earnings	10,358	9,893
Accumulated other comprehensive loss, net	(2,040)	(2,767)
Total shareholders equity	22,732	21,431
BGE preference stock not subject to mandatory redemption	193	193
Non-controlling interest	15	106

Total equity	22,940	21,730
Total liabilities and shareholders equity	$ 79,924	$ 78,561

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	Non-controlling Interest	Preferred and Preference Stock	Total Shareholders Equity
Balance, December 31, 2010	696,589	$ 9,006	$ (2,327)	$ 9,304	$ (2,423)	$ 3	$	$ 13,563
Net income				2,495			4	2,499
Long-term incentive plan activity	861	76						76
Employee stock purchase plan issuances	662	25						25
Common stock dividends				(1,744)				(1,744)
Preferred and preference stock dividends							(4)	(4)
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
Net income (loss)				1,160		(3)	14	1,171
Long-term incentive plan activity	2,432	126						126
Employee stock purchase plan issuances	857	26						26
Common stock dividends				(1,322)				(1,322)
Common stock issuance Constellation merger	188,124	7,365						7,365
Non-controlling interest acquired		8				106		114
BGE preference stock acquired							193	193
Preferred and preference stock dividends							(14)	(14)
Other comprehensive loss, net of income taxes of $(192)					(317)			(317)
Balance, December 31, 2012	889,525	$ 16,632	$ (2,327)	$ 9,893	$ (2,767)	$ 106	$ 193	$ 21,730
Net income (loss)				1,719		(10)	20	1,729
Long-term incentive plan activity	1,445	81						81
Employee stock purchase plan issuances	1,064	28						28
Common stock dividends				(1,254)				(1,254)
Consolidated VIE dividend to non-controlling interest						(63)		(63)
Deconsolidation of VIE						(18)		(18)
Redemption of preferred securities							(6)	(6)
Preferred and preference stock dividends							(14)	(14)
Other comprehensive income, net of income taxes of $(468)					727			727
Balance, December 31, 2013	892,034	$ 16,741	$ (2,327)	$ 10,358	$ (2,040)	$ 15	$ 193	$ 22,940

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	2013	For the Years Ended December 31, 2012	2011
Operating revenues			
Operating revenues	$ 14,207	$ 12,735	$ 9,286
Operating revenues from affiliates	1,423	1,702	1,161
Total operating revenues	15,630	14,437	10,447
Operating expenses			
Purchased power and fuel	6,927	6,017	3,451
Purchased power and fuel from affiliates	1,270	1,044	138
Operating and maintenance	3,960	4,398	2,827
Operating and maintenance from affiliates	574	630	321
Depreciation and amortization	856	768	570
Taxes other than income	389	369	264
Total operating expenses	13,976	13,226	7,571
Equity in earnings (losses) of unconsolidated affiliates	10	(91)	(1)
Operating income	1,664	1,120	2,875
Other income and (deductions)			
Interest expense	(298)	(226)	(170)
Interest expense to affiliates, net	(59)	(75)	
Other, net	368	239	122
Total other income and (deductions)	11	(62)	(48)
Income before income taxes	1,675	1,058	2,827
Income taxes	615	500	1,056
Net income	1,060	558	1,771
Net loss attributable to non-controlling interests	(10)	(4)	
Net income attributable to membership interest	1,070	562	1,771
Comprehensive income (loss), net of income taxes			
Net income	1,060	558	1,771
Other comprehensive income (loss)			
Unrealized loss on cash flow hedges, net of income taxes of $(262), $(262) and $(64), respectively	(398)	(403)	(98)
Unrealized income on equity investments, net of income taxes of $72, $(1) and $0, respectively	107	1	
Unrealized loss on foreign currency translation, net of income taxes of $0, $0 and $0, respectively	(10)		
Unrealized gain on marketable securities, net of income taxes of $0, $0 and $0, respectively	2		
Other comprehensive loss	(299)	(402)	(98)

Comprehensive income	$ 761	$ 156	$ 1,673

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	2013	2012	2011
		For the Years Ended December 31,	
Cash flows from operating activities			
Net income	$ 1,060	$ 558	$ 1,771
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	2,559	2,966	1,539
Loss on sale of three Maryland generating stations		272	
Deferred income taxes and amortization of investment tax credits	315	408	551
Net fair value changes related to derivatives	(448)	(611)	291
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(170)	(157)	14
Other non-cash operating activities	414	537	421
Changes in assets and liabilities:			
Accounts receivable	109	248	(122)
Receivables from and payables to affiliates, net	2	39	208
Inventories	(88)	31	(47)
Accounts payable, accrued expenses and other current liabilities	(109)	(499)	34
Option premiums paid, net	(36)	(114)	(3)
Counterparty collateral (posted) received, net	162	95	(410)
Income taxes	402	114	193
Pension and non-pension postretirement benefit contributions	(149)	(178)	(1,070)
Other assets and liabilities	(136)	(128)	(57)
Net cash flows provided by operating activities	3,887	3,581	3,313
Cash flows from investing activities			
Capital expenditures	(2,752)	(3,554)	(2,491)
Proceeds from nuclear decommissioning trust fund sales	4,217	7,265	6,139
Investment in nuclear decommissioning trust funds	(4,450)	(7,483)	(6,332)
Cash and restricted cash acquired from Constellation		708	
Proceeds from sale of long-lived assets	32	371	
Acquisitions of long lived assets		(21)	(387)
Change in restricted cash	(64)	4	
Changes in Exelon intercompany money pool	(44)		
Distribution from CENG	115		
Other investing activities	30	81	(6)
Net cash flows used in investing activities	(2,916)	(2,629)	(3,077)
Cash flows from financing activities			
Change in short-term debt	13	(52)	
Issuance of long-term debt	854	1,076	
Retirement of long-term debt	(570)	(145)	(2)
Distribution to member	(625)	(1,626)	(172)
Contribution from member	26	48	30
Other financing activities	(82)	(78)	(52)
Net cash flows used in financing activities	(384)	(777)	(196)
Increase in cash and cash equivalents	587	175	40

Cash and cash equivalents at beginning of period	671	496	456
Cash and cash equivalents at end of period	$ 1,258	$ 671	$ 496

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,196	$ 596
Cash and cash equivalents of variable interest entities	62	75
Restricted cash and cash equivalents	19	
Restricted cash and cash equivalents of variable interest entities	52	16
Accounts receivable, net		
Customer	1,429	1,482
Other	353	472
Accounts receivable, net, of variable interest entities	260	292
Mark-to-market derivative assets	727	938
Mark-to-market derivative assets with affiliate		226
Receivables from affiliates	108	141
Receivable from Exelon intercompany money pool	44	
Unamortized energy contract assets	374	886
Inventories, net		
Fossil fuel	164	130
Materials and supplies	671	626
Deferred income taxes	475	
Other	505	331
Total current assets	6,439	6,211
Property, plant and equipment, net	20,111	19,531
Deferred debits and other assets		
Nuclear decommissioning trust funds	8,071	7,248
Investments	400	420
Investment in CENG	1,925	1,849
Mark-to-market derivative assets	600	924
Prepaid pension asset	1,873	1,975
Pledged assets for Zion Station decommissioning	458	614
Unamortized energy contract assets	710	1,073
Other	645	836
Total deferred debits and other assets	14,682	14,939
Total assets	$ 41,232	$ 40,681

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	**December 31, 2013**	**2012**
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 22	$
Long-term debt due within one year	556	24
Long-term debt due within one year of variable interest entities	5	4
Accounts payable	1,152	1,326
Accounts payable of variable interest entities	170	202
Accrued expenses	976	1,116
Payables to affiliates	181	213
Deferred income taxes	25	128
Mark-to-market derivative liabilities	142	334
Unamortized energy contract liabilities	249	378
Other	389	372
Total current liabilities	3,867	4,097
Long-term debt	5,559	5,245
Long-term debt to affiliate	1,523	2,007
Long-term debt of variable interest entities	86	203
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	6,295	5,398
Asset retirement obligations	5,047	4,938
Non-pension postretirement benefit obligations	850	755
Spent nuclear fuel obligation	1,021	1,020
Payables to affiliates	2,740	2,397
Mark-to-market derivative liabilities	120	232
Unamortized energy contract liabilities	266	516
Payable for Zion Station decommissioning	305	432
Other	811	776
Total deferred credits and other liabilities	17,455	16,464
Total liabilities	28,490	28,016
Commitments and contingencies		
Equity		
Member s equity		
Membership interest	8,898	8,876
Undistributed earnings	3,613	3,168
Accumulated other comprehensive income, net	214	513
Total member s equity	12,725	12,557
Non-controlling interest	17	108
Total equity	12,742	12,665
Total liabilities and equity	$ 41,232	$ 40,681

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Changes in Member s Equity

(In millions)	Member s Equity: Membership Interest	Member s Equity: Undistributed Earnings	Member s Equity: Accumulated Other Comprehensive Income	Non-controlling Interest	Total Equity
Balance, December 31, 2010	$ 3,526	$ 2,633	$ 1,013	$ 5	$ 7,177
Net income		1,771			1,771
Distribution to member		(172)			(172)
Allocation of tax benefit from member	30				30
Other comprehensive loss, net of income taxes of $(64)			(98)		(98)
Balance, December 31, 2011	$ 3,556	$ 4,232	$ 915	$ 5	$ 8,708
Net income		562		(4)	558
Distribution to member		(1,626)			(1,626)
Allocation of tax benefit from member	48				48
Acquisition of Constellation	5,264				5,264
Non-controlling interest acquired	8			107	115
Other comprehensive loss, net of income taxes of $(261)			(402)		(402)
Balance, December 31, 2012	$ 8,876	$ 3,168	$ 513	$ 108	$ 12,665
Net income		1,070		(10)	1,060
Distribution to member		(625)			(625)
Allocation of tax benefit from member	26				26
Consolidated VIE dividend to non-controlling interest				(63)	(63)
Deconsolidation of VIE	(1)			(18)	(19)
Non-controlling interest acquired	(3)				(3)
Other comprehensive loss, net of income taxes of $(190)			(299)		(299)
Balance, December 31, 2013	$ 8,898	$ 3,613	$ 214	$ 17	$ 12,742

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(in millions)	For the Years Ended December 31, 2013	2012	2011
Operating revenues			
Operating revenues	$ 4,461	$ 5,441	$ 6,054
Operating revenues from affiliates	3	2	2
Total operating revenues	4,464	5,443	6,056
Operating expenses			
Purchased power	662	1,518	2,382
Purchased power from affiliate	512	789	653
Operating and maintenance	1,211	1,182	1,031
Operating and maintenance from affiliate	157	163	158
Depreciation and amortization	669	610	554
Taxes other than income	299	295	296
Total operating expenses	3,510	4,557	5,074
Operating income	954	886	982
Other income and (deductions)			
Interest expense	(566)	(294)	(330)
Interest expense to affiliates, net	(13)	(13)	(15)
Other, net	26	39	29
Total other income and (deductions)	(553)	(268)	(316)
Income before income taxes	401	618	666
Income taxes	152	239	250
Net income	249	379	416
Other comprehensive income			
Unrealized gain on marketable securities, net of income taxes of $0, $0 and $0, respectively		1	
Other comprehensive income		1	
Comprehensive income	$ 249	$ 380	$ 416

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Cash Flows

	For the Years Ended		
(In millions)	**2013**	**2012**	**2011**
Cash flows from operating activities			
Net income	$ 249	$ 379	$ 416
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	669	610	554
Deferred income taxes and amortization of investment tax credits	(57)	270	700
Other non-cash operating activities	28	252	184
Changes in assets and liabilities:			
Accounts receivable	(12)	24	5
Receivables from and payables to affiliates, net	(12)	(18)	(287)
Inventories	(18)	(11)	(9)
Accounts payable, accrued expenses and other current liabilities	74	59	(84)
Counterparty collateral received, net	53	40	66
Income taxes	178	9	223
Pension and non-pension postretirement benefit contributions	(122)	(138)	(977)
Other assets and liabilities	188	(142)	45
Net cash flows provided by operating activities	1,218	1,334	836
Cash flows from investing activities			
Capital expenditures	(1,433)	(1,246)	(1,028)
Proceeds from sales of investments	7	28	6
Purchases of investments	(4)	(13)	(4)
Change in restricted cash	(2)		
Other investing activities	45	19	19
Net cash flows used in investing activities	(1,387)	(1,212)	(1,007)
Cash flows from financing activities			
Changes in short-term debt	184		
Issuance of long-term debt	350	350	1,199
Retirement of long-term debt	(252)	(450)	(537)
Dividends paid on common stock	(220)	(105)	(300)
Other financing activities	(1)	(7)	(7)
Net cash flows provided by (used in) financing activities	61	(212)	355
Increase (decrease) in cash and cash equivalents	(108)	(90)	184
Cash and cash equivalents at beginning of period	144	234	50
Cash and cash equivalents at end of period	$ 36	$ 144	$ 234

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 36	$ 144
Restricted cash	2	
Accounts receivable, net		
Customer	451	539
Other	584	452
Inventories, net	109	91
Deferred income taxes		83
Counterparty collateral deposited		53
Regulatory assets	329	388
Other	29	25
Total current assets	1,540	1,775
Property, plant and equipment, net	14,666	13,826
Deferred debits and other assets		
Regulatory assets	933	666
Investments	5	8
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivable from affiliates	2,469	2,039
Prepaid pension asset	1,583	1,661
Other	291	299
Total deferred debits and other assets	7,912	7,304
Total assets	$ 24,118	$ 22,905

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	**December 31, 2013**	**2012**
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 184	$
Long-term debt due within one year	617	252
Accounts payable	449	379
Accrued expenses	307	295
Payables to affiliates	83	97
Customer deposits	133	136
Regulatory liabilities	170	170
Mark-to-market derivative liability	17	18
Mark-to-market derivative liability with affiliate		226
Deferred income taxes	16	
Other	72	82
Total current liabilities	2,048	1,655
Long-term debt	5,058	5,315
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,116	4,272
Asset retirement obligations	99	99
Non-pension postretirement benefits obligations	381	273
Regulatory liabilities	3,512	3,229
Mark-to-market derivative liability	176	49
Other	994	484
Total deferred credits and other liabilities	9,278	8,406
Total liabilities	16,590	15,582
Commitments and contingencies		
Shareholders equity		
Common stock	1,588	1,588
Other paid-in capital	5,190	5,014
Retained earnings	750	721
Total shareholders equity	7,528	7,323
Total liabilities and shareholders equity	$ 24,118	$ 22,905

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Changes in Shareholders Equity

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Accumulated Other Comprehensive Income (Loss)	Total Shareholders Equity
Balance, December 31, 2010	$ 1,588	$ 4,992	$ (1,639)	$ 1,970	$ (1)	$ 6,910
Net income			416			416
Common stock dividends				(300)		(300)
Allocation of tax benefit from parent		11				11
Appropriation of retained earnings for future dividends			(416)	416		
Balance, December 31, 2011	$ 1,588	$ 5,003	$ (1,639)	$ 2,086	$ (1)	$ 7,037
Net income			379			379
Common stock dividends				(105)		(105)
Allocation of tax benefit from parent		11				11
Appropriation of retained earnings for future dividends			(379)	379		
Other comprehensive income, net of income taxes of $0					1	1
Balance, December 31, 2012	$ 1,588	$ 5,014	$ (1,639)	$ 2,360	$	$ 7,323
Net income			249			249
Common stock dividends				(220)		(220)
Parent tax matter indemnification		176				176
Appropriation of retained earnings for future dividends			(249)	249		
Balance, December 31, 2013	$ 1,588	$ 5,190	$ (1,639)	$ 2,389	$	$ 7,528

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	2013	For the Years Ended December 31, 2012	2011
Operating revenues			
Operating revenues	$ 3,099	$ 3,183	$ 3,715
Operating revenues from affiliates	1	3	5
Total operating revenues	3,100	3,186	3,720
Operating expenses			
Purchased power and fuel	908	842	1,369
Purchased power from affiliate	392	533	495
Operating and maintenance	647	698	698
Operating and maintenance from affiliates	101	111	96
Depreciation and amortization	228	217	202
Taxes other than income	158	162	205
Total operating expenses	2,434	2,563	3,065
Operating income	666	623	655
Other income and (deductions)			
Interest expense	(103)	(111)	(122)
Interest expense to affiliates, net	(12)	(12)	(12)
Other, net	6	8	14
Total other income and (deductions)	(109)	(115)	(120)
Income before income taxes	557	508	535
Income taxes	162	127	146
Net income	395	381	389
Preferred security dividends and redemption	7	4	4
Net income attributable to common shareholder	388	377	385
Comprehensive income, net of income taxes			
Net income	395	381	389
Other comprehensive income			
Unrealized gain on marketable securities, net of income taxes of $0, $0 and $0, respectively		1	
Other comprehensive income		1	
Comprehensive income	$ 395	$ 382	$ 389

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2013	2012	2011
Cash flows from operating activities			
Net income	$ 395	$ 381	$ 389
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	228	217	202
Deferred income taxes and amortization of investment tax credits	20	37	253
Other non-cash operating activities	108	125	100
Changes in assets and liabilities:			
Accounts receivable	(79)	(14)	225
Receivables from and payables to affiliates, net	(18)	13	(217)
Inventories	2	21	
Accounts payable, accrued expenses and other current liabilities	41	(47)	34
Income taxes	87	174	(45)
Pension and non-pension postretirement benefit contributions	(31)	(45)	(137)
Other assets and liabilities	(6)	16	14
Net cash flows provided by operating activities	747	878	818
Cash flows from investing activities			
Capital expenditures	(537)	(422)	(481)
Changes in intercompany money pool		82	(82)
Change in restricted cash	(2)	2	(2)
Other investing activities	8	10	8
Net cash flows used in investing activities	(531)	(328)	(557)
Cash flows from financing activities			
Payment of accounts receivable agreement	(210)	(15)	
Issuance of long-term debt	550	350	
Retirement of long-term debt	(300)	(375)	(250)
Contributions from parent	27	9	18
Dividends paid on common stock	(332)	(343)	(348)
Dividends paid on preferred securities	(1)	(4)	(4)
Redemption of preferred securities	(93)		
Other financing activities	(2)	(4)	(5)
Net cash flows used in financing activities	(361)	(382)	(589)
Increase (decrease) in cash and cash equivalents	(145)	168	(328)
Cash and cash equivalents at beginning of period	362	194	522
Cash and cash equivalents at end of period	$ 217	$ 362	$ 194

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 217	$ 362
Restricted cash and cash equivalents	2	
Accounts receivable, net ($0 and $289 gross accounts receivable pledged as collateral as of December 31, 2013 and 2012, respectively)		
Customer	360	364
Other	107	161
Inventories, net		
Fossil fuel	60	65
Materials and supplies	21	19
Deferred income taxes	83	40
Prepaid utility taxes	3	21
Regulatory assets	17	32
Other	36	30
Total current assets	906	1,094
Property, plant and equipment, net	6,384	6,078
Deferred debits and other assets		
Regulatory assets	1,448	1,378
Investments	23	22
Investments in affiliates	8	8
Receivable from affiliates	447	360
Prepaid pension asset	363	373
Other	38	40
Total deferred debits and other assets	2,327	2,181
Total assets	$ 9,617	$ 9,353

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	**December 31, 2013**	**2012**
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term notes payable accounts receivable agreement	$	$ 210
Long-term debt due within one year	250	300
Accounts payable	285	244
Accrued expenses	106	82
Payables to affiliates	58	76
Customer deposits	49	51
Regulatory liabilities	106	169
Other	37	26
Total current liabilities	891	1,158
Long-term debt	1,947	1,647
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,487	2,331
Asset retirement obligations	29	29
Non-pension postretirement benefits obligations	286	284
Regulatory liabilities	629	538
Other	99	113
Total deferred credits and other liabilities	3,530	3,295
Total liabilities	6,552	6,284
Commitments and contingencies		
Preferred securities		87
Shareholders equity		
Common stock	2,415	2,388
Retained earnings	649	593
Accumulated other comprehensive income, net	1	1
Total shareholders equity	3,065	2,982
Total liabilities and shareholders equity	$ 9,617	$ 9,353

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Changes in Stockholders Equity

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholders Equity
Balance, December 31, 2010	$ 2,361	$ 522	$	$ 2,883
Net income		389		389
Common stock dividends		(348)		(348)
Preferred security dividends		(4)		(4)
Allocation of tax benefit from parent	18			18
Balance, December 31, 2011	$ 2,379	$ 559	$	$ 2,938
Net income		381		381
Common stock dividends		(343)		(343)
Preferred security dividends		(4)		(4)
Allocation of tax benefit from parent	9			9
Other comprehensive income, net of income taxes of $0			1	1
Balance, December 31, 2012	$ 2,388	$ 593	$ 1	$ 2,982
Net income		395		395
Common stock dividends		(332)		(332)
Preferred security dividends		(1)		(1)
Redemption of preferred securities		(6)		(6)
Allocation of tax benefit from parent	27			27
Balance, December 31, 2013	$ 2,415	$ 649	$ 1	$ 3,065

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2013	2012	2011
Operating revenues			
Operating revenues	$ 3,052	$ 2,725	$ 3,060
Operating revenues from affiliates	13	10	8
Total operating revenues	3,065	2,735	3,068
Operating expenses			
Purchased power and fuel	969	973	1,245
Purchased power from affiliate	452	396	348
Operating and maintenance	551	622	530
Operating and maintenance from affiliates	83	106	150
Depreciation and amortization	348	298	274
Taxes other than income	213	208	207
Total operating expenses	2,616	2,603	2,754
Operating income	449	132	314
Other income and (deductions)			
Interest expense	(106)	(128)	(113)
Interest expense to affiliates, net	(16)	(16)	(16)
Other, net	17	23	26
Total other income and (deductions)	(105)	(121)	(103)
Income before income taxes	344	11	211
Income taxes	134	7	75
Net income	210	4	136
Preference stock dividends	13	13	13
Net income (loss) attributable to common shareholder	$ 197	$ (9)	$ 123
Comprehensive income	$ 210	$ 4	$ 136

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	**For the Years Ended December 31,** **2013**	**2012**	**2011**
Cash flows from operating activities			
Net income	$ 210	$ 4	$ 136
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	348	298	274
Deferred income taxes and amortization of investment tax credits	125	104	145
Other non-cash operating activities	153	193	129
Changes in assets and liabilities:			
Accounts receivable	(127)	(45)	60
Receivables from and payables to affiliates, net	(14)	26	(44)
Inventories	1	25	(10)
Accounts payable, accrued expenses and other current liabilities	(14)	(33)	(21)
Income taxes	(33)	14	35
Pension and non-pension postretirement benefit contributions	(24)	(16)	(67)
Other assets and liabilities	(64)	(85)	(161)
Net cash flows provided by operating activities	561	485	476
Cash flows from investing activities			
Capital expenditures	(587)	(582)	(592)
Change in restricted cash	2		
Other investing activities	14	9	
Net cash flows used in investing activities	(571)	(573)	(592)
Cash flows from financing activities			
Changes in short-term debt	135		
Issuance of long-term debt	300	250	300
Retirement of long-term debt	(467)	(173)	(82)
Dividends paid on common stock			(85)
Dividends paid on preference stock	(13)	(13)	(13)
Contributions from parent		66	
Other financing activities	(3)	(2)	(5)
Net cash flows (used in) provided by financing activities	(48)	128	115
Increase (decrease) in cash and cash equivalents	(58)	40	(1)
Cash and cash equivalents at beginning of period	89	49	50
Cash and cash equivalents at end of period	$ 31	$ 89	$ 49

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 31	$ 89
Restricted cash and cash equivalents of variable interest entity	28	30
Accounts receivable, net		
Customer	480	409
Other	114	111
Income taxes receivable	30	3
Inventories, net		
Gas held in storage	53	51
Materials and supplies	28	31
Deferred income taxes	2	1
Prepaid utility taxes	57	57
Regulatory assets	181	190
Other	7	8
Total current assets	1,011	980
Property, plant and equipment, net	5,864	5,498
Deferred debits and other assets		
Regulatory assets	524	522
Investments	5	5
Investments in affiliates	8	8
Prepaid pension asset	423	467
Other	26	26
Total deferred debits and other assets	986	1,028
Total assets	$ 7,861	$ 7,506

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	2012
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 135	$
Long-term debt due within one year		400
Long-term debt of variable interest entity due within one year	70	67
Accounts payable	270	235
Accrued expenses	111	102
Deferred income taxes	27	
Payables to affiliates	55	69
Customer deposits	76	71
Regulatory liabilities	48	29
Other	35	7
Total current liabilities	827	980
Long-term debt	1,746	1,446
Long-term debt to financing trust	258	258
Long-term debt of variable interest entity	195	265
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,773	1,658
Asset retirement obligations	19	8
Non-pension postretirement benefits obligations	217	229
Regulatory liabilities	204	214
Other	67	90
Total deferred credits and other liabilities	2,280	2,199
Total liabilities	5,306	5,148
Commitments and contingencies		
Shareholders equity		
Common stock	1,360	1,360
Retained earnings	1,005	808
Total shareholders equity	2,365	2,168
Preference stock not subject to mandatory redemption	190	190
Total equity	2,555	2,358
Total liabilities and shareholders equity	$ 7,861	$ 7,506

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statement of Changes in Shareholders Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholders Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2010	$ 1,294	$ 779	$ 2,073	$ 190	$ 2,263
Net income		136	136		136
Common stock dividends		(85)	(85)		(85)
Preference stock dividends		(13)	(13)		(13)
Balance, December 31, 2011	$ 1,294	$ 817	$ 2,111	$ 190	$ 2,301
Net income		4	4		4
Preference stock dividends		(13)	(13)		(13)
Contribution from parent	66		66		66
Balance, December 31, 2012	$ 1,360	$ 808	$ 2,168	$ 190	$ 2,358
Net income		210	210		210
Preference stock dividends		(13)	(13)		(13)
Balance, December 31, 2013	$ 1,360	$ 1,005	$ 2,365	$ 190	$ 2,555

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 (Exelon, Generation, ComEd, PECO and BGE)

Description of Business (Exelon, Generation, ComEd, PECO and BGE)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution businesses. Prior to March 12, 2012, Exelon s principal subsidiaries included ComEd, PECO and Generation. On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger (Merger Agreement). As a result of the merger transaction, Generation now includes the former Constellation generation and customer supply operations. BGE, formerly Constellation s regulated utility subsidiary, is now a subsidiary of Exelon. Refer to Note 4 Merger and Acquisitions for further information regarding the merger transaction.

The energy generation business includes:

Generation: Physical delivery and marketing of owned and contracted electric generation capacity and provision of renewable and other energy-related products and services, and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other regions.

The energy delivery businesses include:

ComEd: Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.

PECO: Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.

BGE: Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Basis of Presentation (Exelon, Generation, ComEd, PECO and BGE)

This is a combined annual report of Exelon, Generation, ComEd, PECO and BGE. The Notes to the Consolidated Financial Statements apply to Exelon, Generation, ComEd, PECO and BGE as indicated parenthetically next to each corresponding disclosure. When appropriate, Exelon, Generation, ComEd, PECO and BGE are named specifically for their related activities and disclosures.

Exelon did not apply push-down accounting to BGE and BGE continued to be subject to reporting requirements as an SEC registrant. The information disclosed for BGE represents the activity of the standalone entity for the twelve months ended December 31, 2013, 2012 and 2011 and the financial position as of December 31, 2013 and December 31, 2012. However, for Exelon s consolidated financial reporting, Exelon is reporting BGE activity from the acquisition date of March 12, 2012 through December 31, 2013.

Each of the Registrant s Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

Combined Notes to Consolidated Financial Statements (Continued)

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

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 BGE, of which Exelon owns 100% of the common stock but none of BGE s preference stock. Exelon owned none of PECO s preferred securities, which PECO redeemed in 2013. Exelon has reflected the third-party interests in ComEd, which totaled less than $1 million at December 31, 2013 and December 31, 2012, as equity, PECO s preferred securities as preferred securities of subsidiary through their redemption in 2013, and BGE s preference stock as BGE preference stock not subject to mandatory redemption in its consolidated financial statements. BGE is subject to some ring-fencing measures established by order of the MDPSC. As part of this arrangement, BGE common stock is held directly by RF Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (BGE Utility), an unrelated party, holds a nominal non-economic interest in RF Holdco LLC with limited voting rights on specified matters.

Generation owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for certain Exelon Wind projects, of which Generation holds a majority interest ranging from 94% to 99% for certain periods of time, and the remaining interests are included in non-controlling interest on Exelon s and Generation s Consolidated Balance Sheets. See Note 2 for further discussion of Exelon s and Generation s VIEs and the reversionary interests of the non-controlling members for certain of these projects.

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 an additional 12.5% is indirectly owned by Exelon. 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, 2013 and December 31, 2012, as equity.

Exelon consolidates the accounts of entities in which Exelon has a controlling financial interest, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% in which Exelon can exercise control over the operations and policies of the investee, or the results of a model that identifies Exelon or one of its subsidiaries as the primary beneficiary of a VIE. Where Exelon does not have a controlling financial interest in an entity, it applies proportional consolidation, equity method accounting or cost method accounting. Exelon applies proportionate consolidation when it has an undivided interest in an asset and is proportionately liable for its share of each liability associated with the asset. Exelon proportionately consolidates its undivided ownership interests in jointly owned electric plants and transmission facilities, as well as its undivided ownership interests in upstream natural gas exploration and production activities. Under proportionate consolidation, Exelon separately records its proportionate share of the assets, liabilities, revenues and expenses related to the undivided interest in the asset. Exelon applies equity method accounting when it has significant influence over an investee through an ownership in common stock, which generally approximates a 20% to 50% voting interest. Exelon applies equity method accounting

Combined Notes to Consolidated Financial Statements (Continued)

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

to certain investments and joint ventures, including the 50.01% interest in CENG, and certain financing trusts of ComEd, PECO, and BGE. Under the equity method, Exelon reports its interest in the entity as an investment and Exelon s percentage share of the earnings from the entity as single line items in its financial statements. Exelon uses the cost method if it holds less than 20% of the common stock of an entity. Under the cost method, Exelon reports its investment at cost and recognizes income only to the extent Exelon receives dividends or distributions.

For the year ended December 31, 2013, BGE recorded a $2 million (pre-tax) correcting adjustment to decrease amortization expense related to regulatory assets that were originally recorded during 2012, an adjustment to decrease income tax expense by $4 million related to the recognition and measurement of regulatory assets that should have been recorded in periods prior to 2013, and a $4 million (pre-tax) correcting adjustment to decrease operating and maintenance expense for an overstatement of BGE s life insurance obligation related to post-employment benefits in prior years. For the year ended December 31, 2012, BGE recorded a $2 million (pre-tax) correcting adjustment to reduce electric distribution revenue related to decoupling of 2011 electric distribution revenue, a $3 million (pre-tax) correcting adjustment to increase electric operations and maintenance expense related to capitalization of electric transmission costs, and a $5 million (pre-tax) correcting adjustment to interest expense to reflect the impacts of amendments of tax positions previously taken on prior-year consolidated income tax returns. In addition, ComEd identified a disclosure adjustment within the renewable energy credits and alternative energy credits section of the 2012 Form 10-K Note 8 Intangible Assets which has been revised in Note 10 of this year s report. Exelon, ComEd and BGE have concluded these correcting adjustments are not material to its results of operations, cash flows, or financial positions for the years ended December 31, 2013, and December 31, 2012, or any prior period.

The accompanying consolidated financial statements have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC.

Use of Estimates (Exelon, Generation, ComEd, PECO and BGE)

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

Reclassifications (Exelon, ComEd, and BGE)

Certain prior year amounts in Exelon s and BGE s Consolidated Statements of Operations and Cash Flows, and Exelon s, ComEd s, and BGE s Consolidated Balance Sheets have been reclassified between line items for comparative purposes and correction of prior period classification errors identified in 2013. The reclassifications did not affect any of the Registrants net income or cash flows from operating activities.

In 2013, Exelon and BGE corrected the presentation of interest expense related to BGE s financing trust of $12 million and $16 million, respectively, to be presented as Interest expense to

Combined Notes to Consolidated Financial Statements (Continued)

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

affiliates, net on their Statements of Operations and Comprehensive Income for the year ended December 31, 2012. BGE also reclassified the related Accrued expenses of $4 million to Payables to affiliates on its December 31, 2012 Balance Sheet. Similar adjustments are also reflected in Note 22 Related Party Transactions. Exelon and Generation also corrected amounts disclosed within Note 22 Related Party Transactions to increase Purchased power and fuel from affiliates by $114 million and to increase Payables to affiliates by $20 million. In 2013, Generation corrected the presentation of interest expense related to certain debt of $75 million to be presented as Interest expense to affiliates, net on its Statement of Operations and Comprehensive Income for the year ended December 31, 2012 and within Note 22 Related Party Transactions.

Accounting for the Effects of Regulation (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE apply the authoritative guidance for accounting for certain types of regulation, which requires ComEd, PECO and BGE 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, PECO and BGE account for their regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the ICC, the PAPUC, and the MDPSC, in the cases of ComEd, PECO and BGE, 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, PECO and BGE 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, PECO s or BGE s business was no longer able to meet the criteria discussed above, the affected entities 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 3 Regulatory Matters for additional information.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Revenues (Exelon, Generation, ComEd, PECO and BGE)

Operating Revenues. Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers. 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. BGE records its best estimate of the transmission revenue impact resulting from changes in rates that BGE believes are probable of approval by FERC in accordance with its formula rate mechanism. See Note 3 Regulatory Matters and Note 6 Accounts Receivable for further information.

RTOs and ISOs. In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, the Registrants generally report sales and purchases conducted on a net hourly basis in

Combined Notes to Consolidated Financial Statements (Continued)

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

either revenues or purchased power on their Consolidated Statements of Operations, the classification of which depends on the net hourly activity. In addition, capacity revenue and expense classification is based on the net sale or purchase position of the Company in the different RTOs and ISOs.

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. The classification of revenue or expense is based on the intent of the transaction. For example, gas transactions may be used to hedge the sale of power. This will result in the change in fair value recorded through revenue. As of the merger date, Exelon and Generation have currently elected to de-designate all of their commodity cash flow hedge positions. As ComEd receives full cost recovery for energy procurement and related costs from retail customers, ComEd records the fair value of its energy swap contracts with unaffiliated suppliers as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets. Refer to Note 3 Regulatory Matters and Note 12 Derivative Financial Instruments for further information.

Proprietary 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. Refer to Note 12 Derivative Financial Instruments for further information.

Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

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 have been deferred on the Registrants Consolidated Balance Sheets and are recognized in book income over the life of the related property. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach; a more-likely-than-not recognition criterion; and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Registrants recognize accrued interest related to unrecognized tax benefits in interest expense or in other income and deductions (interest income) on their Consolidated Statements of Operations.

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 14 Income Taxes for further information.

Taxes Directly Imposed on Revenue-Producing Transactions (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer, but paid by the Registrants, while others are imposed on the Registrants. Where these taxes

Combined Notes to Consolidated Financial Statements (Continued)

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

are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Consolidated Statements of Operations and Comprehensive Income. However, where these taxes are imposed on the Registrants, such as gross receipts taxes or other surcharges or fees, they are reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 23 Supplemental Financial Information for Generation s, ComEd s, PECO s and BGE s utility taxes that are presented on a gross basis.

Cash and Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE)

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

Restricted Cash and Investments (Exelon, Generation, ComEd, PECO and BGE)

Restricted cash and investments represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2013 and 2012, Exelon Corporate s restricted cash and investments primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. Additionally, Exelon Corporate has funds restricted for merger commitments. In addition, Exelon Corporate s investments include its direct financing lease investments. As of December 31, 2013, Generation s restricted cash and investments primarily included cash at Antelope Valley required for debt service and construction and cash at Continental Wind required for debt service and financing of operation and maintenance of the underlying entities. As of December 31, 2012, Generation s restricted cash primarily included cash at Antelope Valley required for debt service and construction. As of December 31, 2013 and 2012, ComEd s restricted cash primarily represented cash collateral held from suppliers associated with ComEd s REC procurement contracts. As of December 31, 2013, PECO s restricted cash primarily represented funds from the sales of assets that were subject to PECO s mortgage indenture. As of December 31, 2013 and 2012, BGE s restricted cash primarily represented funds restricted at its consolidated variable interest entity for repayment of rate stabilization bonds.

Restricted cash and investments not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2013 and 2012, Exelon s and Generation s NDT funds, which are designated to satisfy future decommissioning obligations, were classified as noncurrent assets. As of December 31, 2013, Exelon, Generation, ComEd, PECO and BGE had investments in Rabbi trusts classified as noncurrent assets.

Allowance for Uncollectible Accounts (Exelon, Generation, ComEd, PECO and BGE)

The allowance for uncollectible accounts reflects the Registrants best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging, historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company 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. BGE estimates the allowance for uncollectible accounts on customer receivables by assigning reserve factors for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. ComEd, PECO and BGE customers accounts are generally considered delinquent if the amount billed

Combined Notes to Consolidated Financial Statements (Continued)

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

is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd s, PECO s and BGE s provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 3 Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd.

Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Exelon accounts for its investments in and arrangements with VIEs based on the authoritative guidance which includes the following specific requirements:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events, and
- requires the entity that consolidates a VIE (the primary beneficiary) to present separately on the face of its balance sheet (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

Based on the above accounting guidance, Exelon has adopted the following policies related to variable interest entities:

- Exelon has presented separately on its Consolidated Balance Sheets, to the extent material, the assets of its consolidated VIEs that can only be used to settle specific obligations of the consolidated VIE, and the liabilities of Exelon s consolidated VIEs for which creditors do not have recourse to Exelon s general credit.
- Exelon has qualitatively assessed whether the equity holders of the entity have the power to direct matters that most significantly impact the entity.

See Note 2 Variable Interest Entities for additional information.

Inventories (Exelon, Generation, ComEd, PECO and BGE)

Inventory is recorded at the lower of weighted average 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 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.

Combined Notes to Consolidated Financial Statements (Continued)

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

Emission Allowances. Emission allowances are included in inventory (for emission allowances exercisable in the current year) and other deferred debits (for emission allowances that are exercisable beyond one year) 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 (Exelon, Generation, ComEd, PECO and BGE)

All marketable securities are reported at fair value. Marketable securities held in the NDT funds, certain Generation Rabbi trust investments and BGE s Rabbi trust investments are classified as trading securities and all other securities 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, the Zion generating station and 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. Realized and unrealized gains and losses, net of tax, on certain Generation Rabbi trust investments and BGE s Rabbi trust investments are included in earnings at Exelon, Generation and BGE. Unrealized gains and losses, net of tax, for Generation s, 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 15 Asset Retirement Obligations for information regarding marketable securities held by NDT funds and Note 23 Supplemental Financial Information for additional information regarding ComEd s and PECO s regulatory assets and liabilities.

Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

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, PECO and BGE. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to maintenance expense as incurred. For constructed assets, Exelon capitalizes construction-related direct labor and material costs. ComEd, PECO and BGE also capitalized indirect construction costs including labor and related costs of departments associated with supporting construction activities.

Third parties reimburse ComEd, PECO and BGE for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, Plant and Equipment. DOE SGIG funds reimbursed to PECO and BGE 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 to gross plant when incurred 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 operating and maintenance expense as incurred.

Combined Notes to Consolidated Financial Statements (Continued)

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

For ComEd, PECO and BGE, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation in accordance with the composite method of depreciation. ComEd s and BGE s depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility s regulatory recovery method. ComEd s and BGE s actual incurred removal costs are applied against a 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.

Generation s oil and gas exploration and production activities consist of working interests in gas producing fields. Generation accounts for these activities under the successful efforts method of accounting. Acquisition, development and exploration costs are capitalized. Costs of drilling exploratory wells are initially capitalized and later charged to expense if reserves are not discovered or deemed not to be commercially viable. Other exploratory costs are charged to expense when incurred.

See Note 7 Property, Plant and Equipment, Note 9 Jointly Owned Electric Utility Plant and Note 23 Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel (Exelon and Generation)

The cost of nuclear fuel is capitalized within property, plant and equipment 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 being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed. See Note 22 Commitments and Contingencies for additional information regarding the SNF disposal fee.

Nuclear Outage Costs (Exelon and Generation)

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 (Exelon and Generation)

New site development costs represent the costs incurred in the assessment and design 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 Exelon 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. Capitalized development costs are charged to Operating and maintenance expense when project completion is no longer probable. At December 31, 2013 and 2012, there were no material capitalized development costs for projects not yet under construction included in Property, plant and equipment, net on Exelon s and Generation s Consolidated Balance Sheets. Approximately $10 million, $4 million and $2 million of costs were expensed by Exelon and Generation for the years ended December 31, 2013, 2012, and 2011, respectively. These costs primarily related to the possible development of new renewable energy projects.

Combined Notes to Consolidated Financial Statements (Continued)

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

Capitalized Software Costs (Exelon, Generation, ComEd, PECO and BGE)

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	Exelon	Generation	ComEd	PECO	BGE
December 31, 2013	$ 479	$ 129	$ 101	$ 71	$ 155
December 31, 2012	499	143	105	63	157
Amortization of capitalized software costs	**Exelon (a)**	**Generation (a)**	**ComEd**	**PECO**	**BGE (a)**
2013	$ 198	$67	$52	$ 33	$36
2012	208	81	56	30	32
2011	122	41	50	25	25

(a) Exelon activity for the year ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012 December 31, 2012. Generation activity for the year ended December 31, 2012 includes the results of Constellation for March 12, 2012 December 31, 2012. BGE activity represents the activity for the years ended December 31, 2012 and 2011.

Depreciation, Depletion and Amortization (Exelon, Generation, ComEd, PECO and BGE)

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 and BGE s depreciation includes a provision for estimated removal costs as authorized by the respective regulators. The estimated service lives for ComEd, PECO and BGE 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. 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 7 Property, Plant and Equipment for further information regarding depreciation.

Depletion of oil and gas exploration and production activities is recorded using the units-of-production method over the remaining life of the estimated proved reserves at the field level for acquisition costs and over the remaining life of proved developed reserves at the field level for development costs. The estimates for gas reserves are based on internal calculations.

Amortization of regulatory assets is recorded over the recovery period specified in the related legislation or regulatory agreement. When the recovery or refund period is less than one year, amortization is recorded to the line item in which the deferred cost would have originally been recorded in the Registrants Consolidated Statements of Operations and Comprehensive Income. With exception of income tax-related regulatory assets, when the recovery period is more than one year, the amortization is recorded to Depreciation and amortization in the Registrants Consolidated Statements of Operations and Comprehensive Income. For income tax related regulatory assets, amortization is generally recorded to Income tax expense in the Registrants Consolidated Statements of Operations and Comprehensive Income.

See Note 3 Regulatory Matters and Note 23 Supplemental Financial Information for additional information regarding Generation s nuclear fuel, Generation s ARC and the amortization of ComEd s, PECO s and BGE s regulatory assets.

Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

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. 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. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios. Decommissioning cost studies are updated, on a rotational basis, for each of Generation s nuclear units at least every five years. The liabilities associated with Exelon s non-nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years. Changes to the recorded value of an ARO result from the passage of new laws and regulations, 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, PECO s, and BGE s accretion, through an increase to regulatory assets. See Note 15 Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC (Exelon, Generation, ComEd, PECO and BGE)

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, PECO and BGE 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 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.

Combined Notes to Consolidated Financial Statements (Continued)

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

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

		Exelon [(a)]	Generation [(a)]	ComEd	PECO	BGE [(a)]
2013	Total incurred interest [(b)]	$ 1,423	$ 411	$ 584	$ 117	$ 129
	Capitalized interest	54	54			
	Credits to AFUDC debt and equity	35		16	6	13
2012	Total incurred interest [(b)]	$ 1,003	$ 368	$ 310	$ 125	$ 149
	Capitalized interest	67	67			
	Credits to AFUDC debt and equity	25		9	6	15
2011	Total incurred interest [(b)]	$ 783	$ 219	$ 349	$ 138	$ 136
	Capitalized interest	49	49			
	Credits to AFUDC debt and equity	25		12	13	22

(a) Exelon activity for the year ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012 December 31, 2012. Generation activity for the year ended December 31, 2012 includes the results of Constellation for March 12, 2012 December 31, 2012. BGE activity represents the activity for the years ended December 31, 2012, 2011 and 2010.

(b) Includes interest expense to affiliates.

Guarantees (Exelon, Generation, ComEd, PECO and BGE)

The Registrants recognize, at the inception of a guarantee, a liability for the fair market value of the obligations they have undertaken in issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced as the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 22 Commitments and Contingencies for additional information.

Asset Impairments (Exelon, Generation, ComEd, PECO and BGE)

Long-Lived Assets. The Registrants evaluate the carrying value of their long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. The Registrants determine if long-lived assets and asset groups are impaired by comparing their undiscounted expected future cash flows to their carrying value. Cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Cash flows from Generation plant assets are generally evaluated at a regional portfolio level along with cash flows generated from Generation s supply and risk management activities, including cash flows from contracts that are recorded as intangible contract assets and liabilities on the balance sheet. In certain cases generation assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generation assets (typically contracted renewables).

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

Combined Notes to Consolidated Financial Statements (Continued)

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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.

Conditions that could have an adverse impact on the expected future cash flows and the fair value of the long-lived assets and asset groups include, among other factors, a deteriorating business climate, including energy prices and market conditions, revisions to regulatory laws, or plans to dispose of a long-lived asset significantly before the end of its useful life. See Note 8 Impairment of Long-Lived Assets for additional information.

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 would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 10 Intangible Assets for additional information regarding Exelon s and ComEd s goodwill.

Equity Method Investments. Exelon and Generation regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is not temporary in nature. Additionally, if the project in which Generation holds an investment recognizes an impairment loss, Exelon and Generation would record their proportionate share of that impairment loss and evaluate the investment for an other than temporary decline in value.

Direct Financing Lease Investments. Direct financing lease investments represent the estimated residual values of leased coal-fired plants in Georgia and Texas. Exelon reviews the estimated residual values of its direct financing lease investments and records an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. See Note 8 Impairment of Long-Lived Assets for additional information.

Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

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 derivative contracts intended to serve as economic hedges and that are not designated or do not qualify for hedge accounting or the normal purchases and normal sales exception, 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, interest expense or other, net on the Consolidated Statement of Operations based on the activity the transaction is economically hedging. 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. All amounts classified in earnings related to proprietary trading are

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included in revenue on the Consolidated Statement 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 nature of each transaction.

For commodity derivative contracts, effective with the date of the merger with Constellation, Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation s designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivatives executed to hedge economic risk for commodities are recorded at fair value with changes in fair value recognized through earnings for the combined company.

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 energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. 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 will not be financially settled. Revenues and expenses on derivative 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 rather are recorded on an accrual basis of accounting. See Note 12 Derivative Financial Instruments for additional information.

Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. Effective March 12, 2012, Exelon became the sponsor of all of Constellation s defined benefit pension and other postretirement benefit plans and defined contribution savings plans.

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 or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 16 Retirement Benefits for additional discussion of Exelon s accounting for retirement benefits.

Equity Investment Earnings (Losses) of Unconsolidated Affiliates (Exelon and Generation)

Exelon and Generation include equity in earnings from equity method investments in qualifying facilities, power projects and joint ventures, including Generation s 50.01% interest in CENG, in equity in earnings (losses) of unconsolidated affiliates. Equity in earnings (losses) of unconsolidated affiliates also includes any adjustments to amortize the difference, if any, except for goodwill and land, between

Combined Notes to Consolidated Financial Statements (Continued)

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their cost in an equity method investment and the underlying equity in net assets of the investee at the date of investment. See Note 5 Investment in CENG and Note 25 Related Party Transactions for additional discussion of Exelon s and Generation s investment in CENG.

Exelon and Generation continuously monitor for issues that potentially could impact future profitability of these equity method investments and which could result in the recognition of an impairment loss if such investment experiences an other than temporary decline in value.

New Accounting Pronouncements (Exelon, Generation, ComEd, PECO and BGE)

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

Presentation of Items Reclassified out of Accumulated Other Comprehensive Income

In February 2013, the FASB issued authoritative guidance requiring entities to present either in the notes or parenthetically on the face of the financial statements, reclassifications from each component of accumulated other comprehensive income and the affected income statement line items. Entities only need to disclose the affected income statement line item for components reclassified to net income in their entirety; otherwise, a cross-reference to the related note should be provided. This guidance was effective for the Registrants for periods beginning after December 15, 2012 and was required to be applied prospectively. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Registrants results of operations, cash flows or financial positions. See Note 21 Changes in Accumulated Other Comprehensive Income for the new disclosures.

Disclosures About Offsetting Assets and Liabilities

In December 2011 (and amended in January 2013), the FASB issued authoritative guidance requiring entities to disclose both gross and net information about recognized derivative instruments, including bifurcated embedded derivatives, repurchase and reverse repurchase agreements, and securities borrowing or lending transactions that are offset on the balance sheet or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet. The guidance was effective for the Registrants for periods beginning on or after January 1, 2013 and was required to be applied retrospectively. This guidance is primarily applicable to certain derivative transactions for Exelon and Generation. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Registrants results of operations, cash flows or financial positions. See Note 12 Derivative Financial Instruments for the new disclosures.

Inclusion of the Fed Funds Effective Swap Rate as a Benchmark Interest Rate for Hedge Accounting Purposes

In July 2013, the FASB issued authoritative guidance permitting entities to designate the Fed Funds Effective Swap Rate as a U.S. benchmark interest rate for hedge accounting purposes. Prior to the issuance of this guidance, only interest rates on direct treasury obligations of the U.S. government and the LIBOR swap rate were considered benchmark interest rates in the U.S. This guidance was effective immediately and can be applied prospectively for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. Currently, the Registrants do not use the Fed Funds Effective Swap Rate as a benchmark interest rate, but may in the future.

Combined Notes to Consolidated Financial Statements (Continued)

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

The following recently issued accounting standard is not yet required to be reflected in the combined financial statements of the Registrants.

Presentation of Unrecognized Tax Benefits When Net Operating Loss Carryforwards, Similar Tax Losses or Tax Credit Carryforwards Exist

In July 2013, the FASB issued authoritative guidance requiring entities to present unrecognized tax benefits as a reduction to deferred tax assets for losses or other tax carryforwards that would be available to offset the uncertain tax positions at the reporting date. Currently, the Registrants present their unrecognized tax benefits as liabilities on a gross basis unless an unrecognized tax benefit is directly associated with a tax position taken in a tax year that results in the recognition of a net operating loss or other tax carryforward for that year. This guidance is effective for the Registrants for periods beginning after December 15, 2013 and is required to be applied prospectively, with retroactive application permitted. The Registrants will not retroactively adopt this guidance. This guidance is currently not expected to have an impact on the Registrants upon adoption with the exception of Exelon and Generation in which approximately $11 million of unrecognized tax benefits will be offset against current deferred income assets. The adoption of this standard will not impact the Registrants results of operations.

2. Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

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 equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly impact the entity s economic performance.

At December 31, 2013 and 2012, the Exelon, Generation, and BGE consolidated four and five VIEs or VIE groups, respectively, for which the applicable Registrant was the primary beneficiary. As of December 31, 2013, the Registrants had one VIE for which the Registrants were the primary beneficiary, however, the VIE is immaterial and was not included in the consolidated financial statements or in the consolidated VIE table below. As of December 31, 2013 and 2012, the Registrants had significant interests in eight and nine other VIEs for which the Registrants do not have the power to direct the entities activities, respectively, and accordingly, were not the primary beneficiary.

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

Consolidated Variable Interest Entities

The carrying amounts and classification of the consolidated VIEs assets and liabilities included in the Registrants consolidated financial statements at December 31, 2013 and 2012 are as follows:

	December 31, 2013			December 31, 2012		
	Exelon [(a)]	Generation	BGE	Exelon [(a)(b)]	Generation [(b)]	BGE
Current assets	$ 484	$ 446	$ 28	$ 550	$ 519	$ 30
Noncurrent assets	1,905	1,884	3	1,719	1,680	
Total assets	$ 2,389	$ 2,330	$ 31	$ 2,269	$ 2,199	$ 30
Current liabilities	$ 566	$ 481	$ 74	$ 684	$ 612	$ 71
Noncurrent liabilities	774	562	195	775	470	265
Total liabilities	$ 1,340	$ 1,043	$ 269	$ 1,459	$ 1,082	$ 336

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes total assets of $146 million and total liabilities of $42 million as of December 31, 2012 related to a retail supply company that is not a consolidated VIE as of December 31, 2013. See additional information below.

Except as specifically noted below, the assets in the table above are restricted for settlement of the VIE obligations and the liabilities in the preceding table can only be settled using VIE resources.

RSB BondCo LLC. In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1. BGE has determined that BondCo is a VIE for which it is the primary beneficiary. As a result, BGE consolidates BondCo.

BondCo s assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During 2013, 2012, and 2011, BGE remitted $83 million, $85 million, and $92 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2013. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

Retail Gas Group. During 2009, Constellation formed two new entities, which now are part of Generation, and combined them with its existing retail gas activities into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement with a third-party gas supplier. While Generation owns 100% of these entities, it has been determined that the retail gas entity group is a VIE because there is not sufficient equity to fund the group s activities without the additional credit support that is provided in the form of a parental guarantee. Generation is the primary beneficiary of the retail gas entity group; accordingly, Generation consolidates the retail gas entity group as a VIE.

Combined Notes to Consolidated Financial Statements (Continued)

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

The third-party gas supply arrangement is collateralized as follows:

- The assets of the retail gas entity group must be used to settle obligations under the third-party gas supply agreement before it can make any distributions to Generation,
- The third-party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and
- As of December 31, 2013 Exelon provided a $75 million parental guarantee to the third-party gas supplier in support of the retail gas entity group.

Other than credit support provided by the parental guarantee, Exelon or Generation do not have any contractual or other obligations to provide additional financial support under the collateralized third-party gas supply agreement. The third-party gas supply creditors do not have any recourse to Exelon s or Generation s general credit other than the parental guarantee.

Solar Project Entity Group. In 2011, Constellation formed a group of solar project limited liability companies to build, own, and operate solar power facilities, which are now part of Generation. Additionally, on September 30, 2011, Generation acquired all of the equity interests in Antelope Valley Solar Ranch One (Antelope Valley) from First Solar, Inc., a 230-MW solar PV project under construction in northern Los Angeles County, California. While Generation owns 100% of these entities, it has been determined that certain of the individual solar project entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the solar project entities that qualify as VIEs because Generation controls the design, construction, and operation of the solar power facilities. Generation provides capital funding to these solar VIE entities for ongoing construction of the solar power facilities. In addition, these solar VIE entities have an aggregate amount of outstanding debt with third parties of $536 million, as of December 31, 2013, for which the creditors have no recourse to Generation, however there is limited recourse to Generation with respect to remaining equity contributions necessary to complete the Antelope Valley project. For additional information on these project-specific financing arrangements refer to Note 13 Debt and Credit Agreements.

Retail Power Supply Entity. In August 2013, Generation executed an agreement to terminate its energy supply contract with a retail power supply company that was previously a consolidated VIE. Generation did not have an ownership interest in the entity, but was the primary beneficiary through the energy supply contract. As a result of the termination, Generation no longer has a variable interest in the retail power supply company and ceased consolidation of the entity during the third quarter of 2013. Upon deconsolidation, there was no gain or loss recognized. The assets, liabilities, and non-controlling interest were removed from Exelon s and Generation s balance sheet and the change in non-controlling interest is also reflected on the Statement of Changes in Shareholders Equity and the Statement of Changes in Member s Equity for Exelon and Generation, respectively.

Wind Project Entity Group. Generation owns and operates a number of wind project limited liability entities, the majority of which were acquired on December 9, 2010 when Generation completed the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind). Generation has evaluated the significant agreements and ownership structures and risks of each of its wind projects and underlying entities, and determined that certain of the entities are VIEs because either the projects have non-controlling interest holders that absorb variability from the wind projects, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the wind project entities that

Combined Notes to Consolidated Financial Statements (Continued)

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

qualify as VIEs because Generation controls the design, construction, and operation of the wind power facilities. While Generation owns 100% of the majority of the wind project entities, 10 of the projects have non-controlling equity interests held by third parties, that currently range between 1% and 6%. Of these 10 projects, Generation s current economic interests in nine of the projects are significantly greater than its stated contractual governance rights and all of these projects have reversionary interest provisions that provide the non-controlling interest holder with a purchase option, certain of which are considered bargain purchase prices, which, if exercised, transfers ownership of the projects to the non-controlling interest holder upon either the passage of time or the achievement of targeted financial returns. The ownership agreements with the non-controlling interests state that Generation is to provide financial support to the projects in proportion to its current economic interests in the projects that currently range between 94% and 99%. However, no additional support to these projects beyond what was contractually required has been provided during 2013. As of December 31, 2013, the carrying amount of the assets and liabilities that are consolidated as a result of Generation being the primary beneficiary of the wind VIE entities primarily relate to the wind generating assets, PPA intangible assets and working capital amounts.

As of December 31, 2013 and 2012, ComEd and PECO did not have any consolidated VIEs.

Unconsolidated Variable Interest Entities

Exelon s and Generation s variable interests in unconsolidated VIEs generally include three transaction types: (1) equity investments, (2) energy purchase and sale contracts, and (3) fuel purchase commitments. For the equity investments, the carrying amount of the investments is reflected on their Consolidated Balance Sheets in Investments in affiliates. For the energy purchase and sale contracts and the fuel purchase commitments (commercial agreements), the carrying amount of assets and liabilities in Exelon s and Generation s Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

As of December 31, 2013 and 2012, Exelon and Generation had significant unconsolidated variable interests in eight and nine, respectively, VIEs for which they were not the primary beneficiary; including certain equity investments and certain commercial agreements. The change in the number of unconsolidated variable interests is driven by the completion of certain obligations which cause the entities to no longer be unconsolidated variable interests offset by the addition of an equity investment in a residential solar provider. The following tables present summary information about the significant unconsolidated VIE entities:

December 31, 2013	**Commercial Agreement VIEs**	**Equity Investment VIEs**	**Total**
Total assets [(a)]	$ 128	$ 332	$ 460
Total liabilities [(a)]	17	123	140
Registrants ownership interest [(a)]		86	86
Other ownership interests [(a)]	111	123	234
Registrants maximum exposure to loss:			
Carrying amount of equity investments	7	67	74
Contract intangible asset	9		9

Debt and payment guarantees		5	5
Net assets pledged for Zion Station decommissioning [(b)]	44		44

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

December 31, 2012	**Commercial Agreement VIEs**	**Equity Investment VIEs**	**Total**
Total assets [(a)]	$ 386	$ 354	$ 740
Total liabilities [(a)]	219	114	333
Registrants ownership interest[(a)]		97	97
Other ownership interests [(a)]	167	143	310
Registrants maximum exposure to loss:			
Letters of credit	5		5
Carrying amount of equity investments		77	77
Contract intangible asset	8		8
Debt and payment guarantees		5	5
Net assets pledged for Zion Station decommissioning [(b)]	50		50

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon s or Generation s Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.
(b) These items represent amounts on Exelon s and Generation s Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $458 million and $614 million as of December 31, 2013 and December 31, 2012, respectively; offset by payables to ZionSolutions LLC of $414 million and $564 million as of December 31, 2013 and December 31, 2012, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE. See Note 15 Asset Retirement Obligations for further discussion.

For each unconsolidated VIE, Exelon and Generation assess the risk of a loss equal to their maximum exposure to be remote and, accordingly Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would materially affect the fair value or risk of their variable interests in these variable interest entities.

Energy Purchase and Sale Agreements. In March 2005, Constellation, to which Generation is now a successor, closed a transaction in which Generation assumed from a counterparty two power sales contracts with previously existing VIEs. The VIEs previously were created by the counterparty to issue debt in order to monetize the value of the original contracts to purchase and sell power. Under the power sales contracts, Generation sold power to the VIEs which, in turn, sold that power to an electric distribution utility through 2013. In connection with this transaction, a third-party acquired the equity of the VIEs and Generation loaned that party a portion of the purchase price. If the electric distribution utility were to default under its obligation to buy power from the VIEs, the equity holder could transfer its equity interests to Generation in lieu of repaying the loan. In this event, Generation would have the right to seek recovery of its losses from the electric distribution utility. As a result, Generation has concluded that consolidation was not required. During 2013, the third-party repaid their obligations of the loan with Generation which caused the entities to no longer be unconsolidated VIEs.

ZionSolutions. Generation has an asset sale agreement with EnergySolutions, Inc. and certain of its subsidiaries, including ZionSolutions, LLC (ZionSolutions), which is further discussed in Note 15 Asset Retirement Obligations. Under this agreement, ZionSolutions can put the assets and liabilities back to Generation when decommissioning is complete. Generation has evaluated this agreement and determined that, through the put option, it has a variable interest in ZionSolutions but is not the primary beneficiary. As a result, Generation has concluded that consolidation is not required. Other than the asset sale agreement, Exelon or Generation do not have any contractual or other obligations to provide additional financial support and ZionSolutions creditors do not have any recourse to Exelon s or Generation s general credit.

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Fuel Purchase Commitments. Generation s customer supply 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 22 Commitments and Contingencies. Generation has evaluated these contracts and its membership with NEIL and determined that it either has no variable interest in an entity or, where Generation does have a variable interest in an entity, the variable interest is not significant and it is not the primary beneficiary; therefore, consolidation is not required.

For contracts where Generation has a variable interest, the level of variability being absorbed through the contracts is not considered significant because of the small proportion of the entities activities encompassed by the contracts with Generation. Further, 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 and Generation does not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 22 Commitments and Contingencies. Upon consideration of these factors, Generation does not consider itself to have significant variable interests in these entities or be the primary beneficiary of these VIEs and, accordingly, has determined that consolidation is not required.

Investment in Energy Development Projects. Generation has several equity investments in energy generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each of its equity investments, and determined that certain of the entities are VIEs because Generation guarantees the debt of the entity, provides equity support, or provides operating services to the entity. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the entities that qualify as VIEs because Generation does not have the power to direct the activities of the VIEs that most significantly impact the VIEs economic performance.

Residential Solar Provider. Generation has an equity investment in a residential solar provider. Generation has evaluated the significant agreements, ownership structure and risks of the entity, and determined that the entity is a VIE because it does not have sufficient equity at risk to fund its operations. Generation has determined that its equity investment in the entity is a variable interest. However, Generation has concluded that we are not the primary beneficiary because Generation does not have the power to direct the activities of the VIE that most significantly impact the entity s economic performance. Exelon or Generation do not have any contractual or other obligations to provide additional financial support and the residential solar provider s creditors do not have any recourse to Exelon s or Generation s general credit.

ComEd, PECO and BGE

ComEd s, PECO s, and BGE s retail operations frequently include the purchase of electricity and RECs through procurement contracts of varying durations. See Note 3 Regulatory Matters and Note 22 Commitments and Contingencies for additional information on these contracts. ComEd, PECO

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and BGE have evaluated these types of contracts and have historically determined that either there is no significant variable interest in the entity, or where either ComEd, PECO or BGE does have a significant variable interest in a VIE, ComEd, PECO or BGE would not be the primary beneficiary and, therefore, consolidation would not be required.

For contracts where ComEd, PECO or BGE is considered to have a significant variable interest, consideration is 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, PECO and BGE do not have control over the operation and maintenance of the entities and they do not bear operational risk related to the associated activities. Generally, the carrying amounts of assets and liabilities in ComEd s, PECO s, and BGE s Consolidated Balance Sheets that relate to their involvement with VIEs as a result of commercial arrangements represent the amounts owed by the utilities for the purchases associated with the current billing cycles under the contracts. As of December 31, 2013, the total amount of accounts payable owed by the utilities under agreements with these VIEs was not material. In addition, variability from these contracts is mitigated by the fact that the utilities are able to recover costs incurred under purchase agreements through customer rates. Furthermore, ComEd, PECO and BGE do not have any debt or equity investments in these VIEs and do not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 22 Commitments and Contingencies. Accordingly, none of ComEd, PECO or BGE considers itself to be the primary beneficiary of any VIEs as a result of commercial arrangements.

The financing trust of ComEd, ComEd Financing III, the financing trusts of PECO, PECO Trust III and PECO Trust IV, and the financing trust of BGE, BGE Capital Trust II are not consolidated in Exelon s, ComEd s, PECO s or BGE s financial statements. These financing trusts were created to issue mandatorily redeemable trust preferred securities. ComEd, PECO, and BGE have concluded that they do not have a significant variable interest in ComEd Financing III, PECO Trust III, PECO Trust IV or BGE Capital Trust II as each Registrant financed its equity interest in the financing trusts through the issuance of subordinated debt and, therefore, has no equity at risk. See Note 13 Debt and Credit Agreements for additional information.

3. Regulatory Matters (Exelon, Generation, ComEd, PECO and BGE)

The following matters below discuss the current status of material regulatory and legislative proceedings of the Registrants.

Illinois Regulatory Matters

Energy Infrastructure Modernization Act (Exelon and ComEd).

Background

Since 2011, ComEd s distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois electric utility infrastructure. Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. Throughout each year, ComEd records regulatory assets or regulatory liabilities and

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corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd s best estimate of the revenue requirement expected to be approved by the ICC for that year s reconciliation. As of December 31, 2013, and December 31, 2012, ComEd had a net regulatory asset associated with the distribution formula rate of $463 million and $209 million, respectively.

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 that proceeding was to establish the formula rate under which rates will be calculated going-forward, and the initial rates, which went into effect in late June 2012. On May 29, 2012, the ICC issued an Order (May Order) in that proceeding. The May Order reduced the annual revenue requirement by $168 million, or approximately $110 million more than the proposed reduction by ComEd. Of this incremental revenue requirement reduction, approximately $50 million reflected the ICC s determination that certain costs should be recovered through alternative rate recovery tariffs available to ComEd or will be reflected in a subsequent annual reconciliation, thereby primarily delaying the timing of cash flows. The incremental revenue reduction also reflected a $35 million reduction for the disallowance of return on ComEd s pension asset, a $10 million reduction for incentive compensation related adjustments, and $15 million of reductions for various adjustments for cash working capital, operating reserves, and other technical items. In the second quarter of 2012, ComEd recorded a decrease in revenue of approximately $100 million pre-tax to decrease the regulatory asset for 2011 and for the first three months of 2012 consistent with the terms of the May Order.

On June 22, 2012, the ICC granted an expedited rehearing on three of the issues decided in the May Order. On October 3, 2012, the ICC issued its final order (Rehearing Order) in that rehearing, adopting ComEd s position on the return on its pension asset, resulting in an increase in the annual revenue requirement. For the two other issues, the ICC ruled against ComEd by reaffirming use of an average rather than year-end rate base in the annual reconciliation and amending its prior order to provide a short-term debt rate to apply to the annual reconciliation. In the fourth quarter of 2012, ComEd recorded an increase in revenue of approximately $135 million pre-tax consistent with the terms of the Rehearing Order, of which $75 million pre-tax reflects the reinstatement of the return on pension asset for 2011 and $60 million pre-tax reflects the return on pension asset for 2012. New rates reflecting the impacts of the Rehearing Order went into effect in November 2012. ComEd has filed an appeal with the Illinois Appellate Court. ComEd cannot predict the results of any such appeals.

In March 2013, the Illinois legislature passed Senate Bill 9 to clarify the intent of EIMA on the three issues decided in the Rehearing Order: an allowed return on ComEd s pension asset; the use of year-end rather than average rate base and capital structure in the annual reconciliation; and the use of ComEd s weighted average cost of capital interest rate rather than a short-term debt rate to apply to the annual reconciliation. On May 22, 2013, Senate Bill 9 became effective after the Illinois legislature overrode the Governor s veto of that Bill. On June 5, 2013, the ICC approved ComEd s updated distribution formula rate structure to reflect the impacts of Senate Bill 9.

In October 2013, the ICC opened an investigation (the Investigation), in response to a complaint filed by the Illinois Attorney General, to change the formula rate structure by requesting three changes: the elimination of the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance, the netting of associated accumulated deferred income taxes against the annual reconciliation balance in calculating interest, and the use of average rather than year-end rate base for determining any ROE collar adjustment. On November 26, 2013, the ICC

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issued its final order in the Investigation, rejecting two of the proposed changes but accepting the proposed change to eliminate the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance. The accepted change became effective in January 2014, and is estimated to reduce ComEd s 2014 revenue by approximately $8 million. This change had no financial statement impact on ComEd in 2013. ComEd and intervenors requested rehearing, however all rehearing requests were denied by the ICC. ComEd and intervenors have filed appeals with the Illinois Appellate Court. ComEd cannot predict the results of any such appeals.

Annual Reconciliation

2012 Filing. On April 30, 2012, ComEd filed its annual distribution formula rate. On December 20, 2012, the ICC, issued its final order, which increased the revenue requirement by $73 million, in conformity with the formula rate structure provided in the May 2012 and Rehearing Orders. The $73 million reflected an increase of $80 million for the initial revenue requirement for 2012 and a decrease of $7 million for the annual reconciliation for 2011. The rate increase was set using an allowed return on capital of 7.54% (inclusive of an allowed return on common equity of 9.81%). The rates took effect in January 2013. ComEd and intervenors requested a rehearing on specific issues, which was denied by the ICC. ComEd and intervenors also filed appeals with the Illinois Appellate Court. ComEd cannot predict the results of any such appeals.

On May 30, 2013, ComEd updated its revenue requirement allowed in the December 2012 Order to reflect the impacts of Senate Bill 9, which resulted in a reduction to the current revenue requirement in effect of $14 million. The rates took effect in July 2013.

2013 Filing. On April 29, 2013, ComEd filed its annual distribution formula rate, which was updated in August 2013, to request a total increase to the revenue requirement of $353 million of which approximately $42 million related to Senate Bill 9. On December 19, 2013, the ICC issued its final order which increased the revenue requirement by $341 million, reflecting an increase of $160 million for the initial revenue requirement for 2013 and an increase of $181 million for the annual reconciliation for 2012. The rate increase was set using an allowed return on capital of 6.94% (inclusive of an allowed return on common equity of 8.72%). The rates took effect in January 2014. ComEd requested a rehearing on specific issues, which was denied by the ICC. ComEd also filed an appeal. ComEd cannot predict the results of any such appeals.

Expenditures and Capital Investment

As part of the enactment of EIMA legislation ComEd made an initial contribution of $15 million (recognized as expense in 2011) to a new Science and Technology Innovation Trust fund on July 31, 2012, and will make recurring annual contributions of $4 million, the first of which was made on December 31, 2012, which will be used for customer education for as long as the AMI Deployment Plan remains in effect. In addition, ComEd will contribute $10 million per year for five years, as long as ComEd is subject to EIMA, to fund customer assistance programs for low-income customers, which will not be recoverable through rates. These contributions began in 2012.

On January 6, 2012, ComEd filed its Infrastructure Investment Plan with the ICC. Under that plan, ComEd will invest approximately $2.6 billion over ten years to modernize and storm-harden its distribution system and to implement smart grid technology. On April 23, 2012, ComEd filed its initial AMI Deployment Plan with the ICC, which was approved by the ICC on June 22, 2012, with certain modifications. ComEd outlined the new deployment schedule within testimony provided in the AMI Plan Rehearing and filed a revised AMI deployment plan. The deployment plan provides for the installation of 4 million electric smart meters, of which more than 60,000 meters were installed by the end of 2013.

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Appeal of 2007 Illinois Electric Distribution Rate Case (Exelon and ComEd). 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).

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. 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 electric distribution rate case (2010 Rate Case) became effective. In subsequent ICC proceedings, the ICC issued an order requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation issue. On March 26, 2012, ComEd filed a notice of appeal with the Court.

However, on September 27, 2013 the Court ruled against ComEd on the accumulated depreciation issue and affirmed that ComEd owes a refund to customers of $37 million. As of December 31, 2013, and December 31, 2012, ComEd was fully reserved for this liability. ComEd will not seek rehearing or appeal on this matter and is working with the ICC on the process and timing for a refund to customers.

Advanced Metering Program Proceeding (Exelon and ComEd) ComEd s 2007 Rate Case filing included a system modernization rider, which permitted investments in AMI to study the costs and benefits and to develop the cost estimate of full system-wide implementation. In October 2009, the ICC approved a modified version of ComEd s system modernization rider proposed in the 2007 Rate Case, Rider AMP (Advanced Metering Program). ComEd collected approximately $24 million under Rider AMP through December 31, 2013. Several other parties, including the Illinois Attorney General, appealed the ICC s order on Rider AMP. In ComEd s 2010 electric distribution rate case, the ICC approved ComEd s transfer of other costs from recovery under Rider AMP to recovery through electric distribution rates. On March 19, 2012, the Court reversed the ICC s approval of Rider AMP, concluding that the ICC s October 2009 approval of the rider constituted single-issue ratemaking. ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court on April 23, 2012, which was denied in September 2012, and the matter was returned to the ICC to calculate a refund amount. ComEd believes any refund obligation associated with Rider AMP should be prospective from no earlier than the date of the Appellate Court s order on March 19, 2012. As a result, ComEd recorded a regulatory liability of approximately $0.4 million at December 31, 2013, which represents the amounts collected from customers since March 19, 2012. ComEd cannot predict the ultimate outcome of the ICC proceeding and therefore, actual refunds may differ from the estimated accrual recorded at December 31, 2013.

2010 Illinois Electric Distribution Rate Case (Exelon and ComEd). 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. ComEd originally requested a $396 million increase, although it was subsequently reduced to $343 million to account for various adjustments. As expected, the ICC followed the Court s ruling on ComEd s 2007 Rate Case on the post-test year accumulated depreciation issue. The order allowed ComEd to establish or reestablish a net amount of approximately

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$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 in 2011. The order also affirmed the current regulatory asset for severance costs, which was challenged by an intervener in the 2010 Rate Case. The order was appealed to the Court by several parties on a number of issues. On May 16, 2013, the Court dismissed as moot the appeals of the ICC s order in the 2010 Rate Case as ComEd now recovers distribution costs under EIMA through a pre-established formula rate tariff.

Utility Consolidated Billing and Purchase of Receivables (Exelon and ComEd). 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, 2013, the balance of purchased accounts receivable was $105 million. Under the applicable tariff, ComEd recovers from RES and customers the costs for implementing and operating the program. A number of municipalities, including the City of Chicago have switched to RES electric supply. As a result, ComEd experienced a significant increase in the amount of RES receivables it purchased in 2013.

Illinois Procurement Proceedings (Exelon, Generation and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, as a result of 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. On December 21, 2011, the ICC approved the IPA s procurement plan covering the period June 2012 through May 2017.

The Illinois Settlement Legislation requires ComEd to purchase an increasing percentage of the electricity it purchases for customer deliveries from renewable energy resources. Purchases by customers of electricity from competitive generation suppliers, whether as a result of the customers own actions or as a result of municipal aggregation, are not included in this calculation and have the effect of reducing ComEd s purchase obligation. ComEd entered into several 20-year contracts with unaffiliated suppliers in December 2010 regarding the procurement of long-term renewable energy and associated RECs in order to meet its obligations under the state s RPS. Under the Illinois Settlement Legislation, all associated costs are recoverable from customers.

As a result of reduced ComEd load forecasts, purchases under the existing long-term contracts for energy and the associated RECs were reduced on a pro-rata basis under the terms of those contracts for the June 2013 May 2014 period to keep the purchases under the statutory rate impact cap. The curtailment s impact on ComEd s financial position and cash flows was immaterial.

On December 18, 2013, the ICC approved the IPA s 2014-2019 procurement plan. The plan provides for two separate energy procurements during 2014 to address potential fluctuations in energy demand due to customer switching between ComEd and competitive electric generation suppliers. The Commission also approved the IPA s expansion of energy efficiency programs for both ComEd and Ameren. The ICC did not require the acquisition of additional renewable resources in 2014-2015 due to insufficient available funds to procure those resources. Further, the ICC again approved a reduction of purchases under the existing long-term contracts for energy and the associated RECs on a pro-rata basis under the terms of those contracts for the June 2014 May 2015 period to keep the purchases under the statutory rate impact cap; however the amount of the reduction will not be finalized and approved by the ICC until March 2014. The curtailment s impact on ComEd s financial position and

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cash flows is expected to be immaterial. See Note 12 Derivative Financial Instruments for additional information regarding ComEd s financial swap contract with Generation, which expired in May 2013, and long-term renewable energy contracts.

During 2013, the ICC approved, and directed ComEd and Ameren (the Utilities) to enter into 20-year sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The sourcing agreement provides that the Utilities will pay FutureGen s contract prices, which are set annually pursuant to a formula rate. The contract prices are based on the difference between the costs of the facility and the revenues FutureGen receives from selling capacity and energy from the unit into the MISO or other markets, as well as any other revenue FutureGen receives from the operation of the facility. The order also directs the Utilities to recover (or pass along) these costs from the Utilities distribution system customers, regardless of whether they purchase electricity from the utility or from competitive electric generation suppliers. In February 2013, ComEd filed an appeal with the Illinois Appellate Court questioning the legality of requiring ComEd to procure power for retail customers purchasing electricity from competitive electric generation suppliers.

On August 22, 2013, the Utilities executed the sourcing agreement with FutureGen in accordance with the ICC order. However, in the event the order is reversed as a result of the appeal, ComEd s obligations under the sourcing agreement should be suspended. Depending on the ultimate outcome of the appeals, the eventual market conditions and the cost of the facility, the sourcing agreement could have a material adverse impact on Exelon s and ComEd s cash flows and financial positions.

See Note 22 Commitments and Contingencies for additional information on ComEd s energy commitments.

Energy Efficiency and Renewable Energy Resources (Exelon and ComEd). 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 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.

EIMA provides for additional energy efficiency in Illinois. Starting in the June 2013 May 2014 period and occurring annually thereafter, as part of the IPA procurement plan, ComEd is to include cost-effective expansion of current energy efficiency programs, and additional new cost-effective program and/or third-party energy efficiency programs that are identified through a request for proposal process. All cost-effective energy efficiency programs are included in the IPA procurement plan for consideration of implementation. While these programs are monitored separately from the Energy Efficiency Portfolio Standard (EEPS), funds for both the EEPS portfolio and IPA energy efficiency programs are collected under the same rider.

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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. All goals are subject to rate impact criteria set forth in the Illinois Settlement Legislation. As of December 31, 2013, 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 22 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 (Exelon and PECO). 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 tax years prior to 2011 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 have been reflected in customer bills since January 1, 2012.

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The expected total refund to customers for the tax cash benefit from the application of the new method to costs incurred prior to 2011 is $54 million. This amount is subject to adjustment based on the outcome of IRS examinations. Credits have been reflected in customer bills since January 1, 2013. PECO currently anticipates that the IRS will issue guidance in early 2014 providing a safe harbor method of accounting for gas transmission and distribution property.

The prospective tax benefits claimed as a result of the new methodology will be reflected in tax expense in the year in which they are claimed on the tax return and will be reflected in the determination of revenue requirements in the next electric and natural gas distribution rate cases. See Note 14 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.

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Pennsylvania Procurement Proceedings (Exelon and PECO). PECO s first PAPUC approved DSP Program, under which PECO was providing default electric service, had a 29-month term that ended May 31, 2013. On October 12, 2012, the PAPUC issued its Opinion and Order approving PECO s second DSP Program, which was filed with the PAPUC in January 2012. The program, which has a 24-month term from June 1, 2013 through May 31, 2015, complies with electric generation procurement guidelines set forth in Act 129. Under the DSP Programs, 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. In addition, PECO s second DSP Program provides for the recovery of AEPS compliance costs through the GSA rather than a separate AEPS rider.

In the second DSP Program, PECO is procuring electric supply for its default electric customers through five competitive procurements. The load for the residential and small and medium commercial classes is served through competitively procured fixed price, full requirements contracts of two years or less. For the large commercial and industrial class load, PECO has competitively procured contracts for full requirements default electric generation with the price for energy in each contract set to be the hourly price of the spot market during the term of delivery. In December 2012 and February 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in June 2013. In September 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in December 2013. In January 2014, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small, medium, and large commercial classes that will begin in June 2014. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO s Statement of Operations and Comprehensive Income.

In addition, the second DSP Program includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from electric generation suppliers beginning April 1, 2014. On May 1, 2013, PECO filed a Petition for Approval of its CAP Shopping Plan with the PAPUC, which the PAPUC granted and denied in part on January 9, 2014. PECO and other parties to the proceeding filed petitions for reconsideration of the Commission s decision on February 10, 2014, and these petitions are currently pending before the PAPUC.

Smart Meter and Smart Grid Investments (Exelon and PECO). Pursuant to Act 129 and the follow-on Implementation Order of 2009, in April 2010, the PAPUC approved PECO s Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million smart meters and an AMI communication network by 2020. The first phase of PECO s SMPIP, which was completed on June 19, 2013, included the installation of an AMI communications network and the deployment of 600,000 smart meters to communicate with that network. On May 31, 2013, PECO and interested parties filed a Joint Petition for Settlement of the universal deployment plan with the PAPUC which was approved without modification on August 15, 2013. The Joint Petition for Settlement supports all material aspects of PECO s universal deployment plan, including cost recovery, excluding certain amounts discussed below. Universal deployment is the second phase of PECO s SMPIP, under which PECO will deploy the remainder of the 1.6 million smart meters on an accelerated basis by the end of 2014. In total, PECO currently expects to spend up to $595 million, excluding the cost of the original meters (as further described below), on its smart meter infrastructure and approximately

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$120 million on smart grid investments through 2014 of which $200 million will be funded by SGIG as discussed below. As of December 31, 2013, PECO has spent $423 million and $116 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received to date.

Pursuant to the ARRA of 2009, PECO and the DOE entered into a Financial Assistance Agreement to extend PECO $200 million in non-taxable SGIG funds of which $140 million relates to smart meter deployment and $60 million relates to smart grid infrastructure. As part of the agreement, the DOE has a conditional ownership interest in qualifying Federally-funded project property and equipment, which is subordinate to PECO s existing mortgage. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. As of December 31, 2013, PECO has received $190 million of the $200 million in reimbursements. PECO s outstanding receivable from the DOE for reimbursable costs was $3 million as of December 31, 2013, which has been recorded in Other accounts receivable, net on Exelon s and PECO s Consolidated Balance Sheets.

On August 15, 2012, PECO suspended installation of smart meters for new customers based on a limited number of incidents involving overheating meters. Following its own internal investigation and additional scientific analysis and testing by independent experts completed after September 30, 2012, PECO announced its decision to resume meter deployment work on October 9, 2012. PECO has replaced the previously installed meters with an alternative vendor s meters. PECO is moving forward with the alternative meters during universal deployment and continues to evaluate meters from several vendors and may use more than one meter vendor during universal deployment.

Following PECO s decision, as of October 9, 2012 PECO will no longer use the original smart meters. For the meters that will no longer be used, the accounting guidance requires that any difference between the carrying value and net realizable value be recognized in the current period s earnings, before considering potential regulatory recovery. The cost of the original meters, including installation and removal costs, owned by PECO was approximately $17 million, net of approximately $16 million of reimbursements from the DOE and approximately $2 million of depreciation. PECO requested and received approval from the DOE that the original meters continue to be allowable costs and that any agreement with the vendor will not be considered project income. In addition, PECO remains eligible for the full $200 million in SGIG funds. On August 15, 2013, PECO entered into an agreement with the original vendor, which was part of the final agreement discussed below, under which PECO transferred the original uninstalled meters to the vendor and will receive $12 million in return, of which $7 million has been received as of December 31, 2013. On January 23, 2014, PECO entered a final agreement with the vendor pursuant to which PECO will be reimbursed for amounts incurred for the original meters and related installation and removal costs, via cash payments and rebates on future purchases of licenses, goods and services primarily through 2017. PECO previously had intended to seek regulatory rate recovery in a future filing with the PAPUC of amounts not recovered from the vendor. As PECO believed such costs were probable of rate recovery based on applicable case law and past precedent on reasonably and prudently incurred costs, a regulatory asset was established at the time of the removals. As of December 31, 2013 and 2012, $5 million and $17 million, respectively, was recorded on Exelon s and PECO s Consolidated Balance Sheets. Pursuant to the January 23, 2014, vendor agreement, PECO will reclassify the regulatory asset balance as a receivable, with no gain or loss impacts on future results of operations.

Energy Efficiency Programs (Exelon and PECO). PECO s PAPUC-approved Phase I EE&C Plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I plan set forth how PECO would meet the required reduction targets established by Act 129 s EE&C provisions,

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which included a 3% reduction in electric consumption in PECO s service territory and a 4.5% reduction in PECO s annual system peak demand in the 100 hours of highest demand by May 31, 2013.

The peak demand period ended on September 30, 2012 and PECO communicated its compliance with the reduction targets in a preliminary filing with the PAPUC on March 1, 2013. The final compliance report for all Phase I targets, was filed with the PAPUC on November 15, 2013.

On March 29, 2013, PECO filed a Petition with the PAPUC to change the recovery period of certain Direct Load Control (DLC) Program costs necessary to implement the Phase I Plan. The Petition sought approval to allow PECO to recover $12 million in equipment, installation and information technology costs for its Residential DLC program with the amounts collected for the Phase I Plan. As the Phase I Plan was implemented at a cost less than originally budgeted, PECO proposed to recover these expenses from its Phase I Energy Efficiency Program Charge over-collection consistent with PAPUC guidance to recover all Phase I costs through Phase I funding. The PAPUC approved PECO s Petition on May 9, 2013. A regulatory liability was established for the DLC program costs that will be amortized as a credit to the income statement to offset the related depreciation expense during the same period.

The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provides energy consumption reduction requirements for the second phase of Act 129 s EE&C programs, which went into effect on June 1, 2013. The order tentatively established PECO s three-year cumulative consumption reduction target at 1,125,852 MWh, which was reaffirmed by the PAPUC on December 5, 2012.

Pursuant to the Phase II implementation order, PECO filed its three-year EE&C Phase II plan with the PAPUC on November 1, 2012. The plan sets forth how PECO will reduce electric consumption by at least 1,125,852 MWh in its service territory for the period June 1, 2013 through May 31, 2016, adjusted for weather and extraordinary loads. The implementation order permits PECO to apply any excess savings achieved during Phase I against its Phase II consumption reduction targets, with no reduction to its Phase II budget. In accordance with the Act 129 Phase II implementation order, at least 10% and 4.5% of the total consumption reductions must be through programs directed toward PECO s public and low income sectors, respectively. If PECO fails to achieve the required reductions in consumption, it will be subject to civil penalties of up to $20 million, which would not be recoverable from ratepayers. Act 129 mandates that the total cost of the plan may not exceed 2% of the electric company s total annual revenue as of December 31, 2006.

On March 15, 2013, PECO filed a Petition for Approval to amend its EE&C Phase II Plan to continue its DLC demand reduction program for mass market customers from June 1, 2013 to May 31, 2014. PECO proposed to fund the estimated $10 million costs of the one-year program by modifying incentive levels for other Phase II programs. On May 9, 2013, the PAPUC approved PECO s amended EE&C Phase II plan. The costs of DLC program will be recovered through PECO s Energy Efficiency Program Charge along with all other Phase II Plan costs.

On November 14, 2013, the PAPUC issued a Tentative Order on Act 129 demand reduction programs which seeks comments on a proposed demand response program methodology for future Act 129 demand reduction programs as well as demand response potential and wholesale prices suppression studies. The comment process is scheduled to be completed in the first quarter of 2014. Any decision reached would affect PECO s EE&C Plan subsequent to its Phase II Plan.

Alternative Energy Portfolio Standards (Exelon and PECO). In November 2004, Pennsylvania adopted the AEPS Act. The AEPS Act mandated that beginning in 2011, following the expiration of

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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% and the requirement for Tier II alternative energy resources ranges from 6.2% to 10%. 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.

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 s second DSP Program eliminated the AEPS surcharge. Beginning in June 2013, AEPS compliance costs are being recovered through the GSA.

Investigation of Pennsylvania Retail Electricity Market (Exelon and PECO). 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 March 1, 2012, the PAPUC issued the final order describing more detailed recommendations to be implemented prior to the expiration of the electric distribution company s current default service plan and providing guidelines for electric distribution companies for development of their next default service plan. On October 12, 2012, the PAPUC approved PECO s second DSP Program, which includes 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. Further, the PAPUC issued a final order on February 14, 2013, outlining its proposed end-state for default service, which included default service pricing for residential and small commercial customers based on three month full requirements contracts, full requirement contracts using hourly spot market pricing for large commercial and industrial default service customers, and the inclusion of CAP customers in the customer choice programs.

Pennsylvania Act 11 of 2012 (Exelon and PECO). On February 13, 2012, Act 11 was signed into law by the Governor. Act 11 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. Act 11 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 first year rates are in effect. On August 2, 2012, the PAPUC issued a final order establishing rules and procedures to implement the ratemaking provisions of Act 11. The implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) which outlines how the utility is planning to increase its investment for repairing, improving, or replacing aging infrastructure, approved by the Commission prior to implementing a DSIC. On May 9, 2013, the PAPUC approved PECO s LTIIP for its Gas Operations, which was filed on February 8, 2013.

Maryland Regulatory Matters

2011 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated electric and gas distribution rate order issued in December 2010. As part of the March 2011 comprehensive rate order, BGE was authorized to defer $19 million of costs as regulatory assets. These costs are being recovered over a 5-year period that began in December 2010 and include the deferral of $16 million of storm costs incurred in February 2010. The regulatory asset for the storm costs earns a regulated rate of return.

2012 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 27, 2012, BGE filed an application for increases to its electric and gas base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order in BGE s 2012 electric and natural gas distribution rate case for increases in annual distribution service revenue of $81 million and $32 million, respectively. The electric distribution rate increase was set using an allowed return on equity of 9.75% and the gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved electric and natural gas distribution rates became effective for services rendered on or after February 23, 2013. As part of the rate order, the MDPSC approved both recovery of and return on merger integration costs incurred during the test year, including severance. As a result, the order affirmed the treatment of $20 million of severance-related costs that BGE had recorded as a regulatory asset in 2012, consistent with prior MDPSC decisions. Additionally, BGE established a new regulatory asset of $8 million related to non-severance merger integration costs, which includes $6 million of costs incurred during 2012. Current MDPSC treatment of these merger integration regulatory assets is to provide recovery over a five year period.

2013 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On May 17, 2013, BGE filed an application for increases of $101 million and $30 million to its electric and gas base rates, respectively, with the MDPSC. The requested rates of return on equity in the application were 10.50% and 10.35% for electric and gas distribution, respectively. In addition to these requested rate increases, BGE s application includes a request for recovery of incremental capital expenditures and operating costs associated with BGE s proposed short-term reliability improvement plan in response to a MDPSC order through a surcharge separate from base rates. On August 23, 2013, BGE filed an update to its rate request which altered the requested increase to electric base rates from $101 million to $83 million and the requested increase to gas base rates from $30 million to $24 million. On December 13, 2013, the MDPSC issued an order in BGE s 2013 electric and natural gas distribution rate case for increases in annual distribution service revenue of $34 million and $12 million, respectively. The electric distribution rate increase was set using an allowed return on equity of 9.75% and the gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved electric and natural gas distribution rates became effective for services rendered on or after December 13, 2013. The MDPSC also conditionally approved five of the eight programs included in BGE s proposed short-term reliability improvement plan. Commencement of the program and recovery are dependent on final MDPSC approval with the surcharge starting no earlier than April 1, 2014.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million. The MDPSC s approval ordered BGE to defer the associated incremental costs, depreciation

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and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of December 31, 2013 and December 31, 2012, BGE recorded a regulatory asset of $66 million and $31 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. Additionally, the MDPSC has determined that the cost recovery for the non-AMI meters that BGE retires will be considered in a future depreciation proceeding. The MDPSC continues to evaluate the impacts of a customer opt-out feature in BGE s Smart Grid program. In March 2013, BGE filed a description of the overall additional costs associated with allowing customers to retain their current meter, and for radio frequency (RF)-Free and RF-Minimizing options related to the installation of their smart meters as well as a proposed cost recovery mechanism. The MDPSC held a hearing in August 2013 to consider the filings made by BGE and other Maryland electric utilities. The ultimate resolution related to this feature could affect BGE s ability to demonstrate cost-effectiveness of the advanced metering system. Overall, BGE continues to believe the recovery of smart grid initiative costs in future rates is probable as BGE expects to be able to demonstrate that the program benefits exceed costs. Pursuant to the ARRA of 2009, BGE is a recipient of $200 million in federal funding from the DOE for its smart grid and other related initiatives, which substantially reduces the total cost of these initiatives to BGE s ratepayers. The project to install the smart meters began in late April 2012. As of December 31, 2013, BGE had received $200 million in reimbursements from the DOE.

New Electric Generation (Exelon and BGE). On April 12, 2012, the MDPSC issued an order directing BGE and two other Maryland utilities to enter into a contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW natural gas-fired combined-cycle generation plant in Waldorf, Maryland, that CPV projected will be in commercial operation by June 1, 2015. The initial term of the proposed contract is 20 years. The CfD mandates that BGE and the other utilities pay (or receive) the difference between CPV s contract prices and the revenues CPV receives for capacity and energy from clearing the unit in the PJM capacity market. The MDPSC s Order requires the three Maryland utilities to enter into a CfD in amounts proportionate to their relative SOS load.

On April 16, 2013, the MDPSC issued an order that required BGE to execute a specific form of contract with CPV, and the parties executed the contract as of June 6, 2013. As of December 31, 2013, there is no impact on Exelon s and BGE s results of operations, cash flows and financial positions. Furthermore, the agreement does not become effective until the resolution of certain items, including all current litigation.

On April 27, 2012, a civil complaint was filed in the U.S. District Court for the District of Maryland by certain unaffiliated parties that challenges the actions taken by the MDPSC on Federal law grounds. On October 24, 2013, the U.S. District Court issued a judgment order finding that the MDPSC s Order directing BGE and the two other Maryland utilities to enter into a CfD, which assures that CPV receives a guaranteed fixed price regardless of the price set by the federally regulated wholesale market, violates the Supremacy Clause of the United States Constitution. On November 22, 2013, the MDPSC and CPV appealed the District Court s ruling to the United States Court of Appeals for the Fourth Circuit.

On May 4, 2012, BGE filed a petition in the Circuit Court for Anne Arundel County, Maryland, seeking judicial review of the MDPSC order under state law. That petition was subsequently transferred to the Circuit Court for Baltimore City and consolidated with similar appeals that have been filed by other interested parties. On October 1, 2013, the Circuit Court Judge issued a Memorandum Opinion and Order finding the decisions of the MDPSC were within its statutory authority under

Maryland law. This decision is separate from the judgment in the federal litigation that the MDPSC Order is unconstitutional and the CfD is unenforceable under federal law. The federal judgment, if upheld, would prevent enforcement of the CfD even if the Circuit Court decision stands. On October 29, 2013, BGE and the two other Maryland utilities appealed the Circuit Court s ruling to the Maryland Court of Special Appeals.

Depending on the ultimate outcome of the pending state and federal litigation, on the eventual market conditions, and on the manner of cost recovery as of the effective date of the agreement, the CfD could have a material impact on Exelon and BGE s results of operations, cash flows and financial positions.

Exelon believes that this and other states projects may have artificially suppressed capacity prices in PJM and may continue to do so in future auctions to the detriment of Exelon s market driven position. In addition to this litigation, Exelon is working with other market participants to implement market rules that will appropriately limit the market suppressing effect of such state activities.

MDPSC Derecho Storm Order (Exelon and BGE). Following the June 2012 Derecho storm which hit the mid-Atlantic region interrupting electrical service to a significant portion of the State of Maryland, the MDPSC issued an order on February 27, 2013 requiring BGE and other Maryland utilities to file several comprehensive reports with short-term and long-term plans to improve reliability and grid resiliency that were due at various times before August 30, 2013.

On September 3, 2013, BGE filed a comprehensive long term assessment examining potential alternatives for improving the resiliency of the electric grid and a staffing analysis reviewing historical staffing levels as well as forecasting staffing levels necessary under various storm scenarios. BGE currently cannot predict the outcome of these proceedings, which may result in increased capital expenditures and operating costs.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. On May 2, 2013, the Governor of Maryland signed the legislation into law; which took effect June 1, 2013. Under the new law, following a proceeding before the MDPSC and with the MDPSC s approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. The legislation includes caps on the monthly surcharges to residential and non-residential customers, and would require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. The MDPSC held evidentiary hearings on BGE s proposed plan and surcharge from November 12, 2013 through November 14, 2013. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE s plan and surcharge. BGE must submit a list detailing specific projects planned for 2014 to the MDPSC for approval within 30 days of the decision. Upon approval of the project list by the MDPSC, BGE will be able to implement the surcharge rates on gas customers bills. The new surcharges are expected to take effect in second quarter of 2014. In addition, BGE will be subject to an annual independent audit to review plan performance and progress.

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Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd and BGE). ComEd s and BGE s transmission rates are each established based on a FERC-approved formula.

ComEd s most recent annual formula rate update filed in April 2013 reflects 2012 actual costs plus forecasted 2013 capital additions. The update resulted in a revenue requirement of $488 million plus a $25 million adjustment related to the reconciliation of 2012 actual costs for a net revenue requirement of $513 million. This compares to the May 2012 updated revenue requirement of $450 million offset by a $5 million reduction related to the reconciliation of 2011 actual costs for a net revenue requirement of $445 million. The increase in the revenue requirement was primarily driven by increased capital investment, higher pension and post-retirement healthcare costs, and higher operating and maintenance costs. The 2013 net revenue requirement became effective June 1, 2013, and is being recovered over the period extending through May 31, 2014. The regulatory asset associated with the true-up is being amortized as the associated amounts are recovered through rates.

ComEd s updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.70%, a decrease from the 8.91% 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%.

BGE s most recent annual formula rate update filed in April 2013 reflects actual 2012 expenses and investments plus forecasted 2013 capital additions. The update resulted in a revenue requirement of $158 million offset by a $1 million reduction related to the reconciliation of 2012 actual costs for a net revenue requirement of $157 million. This compares to the April 2012 updated revenue requirement of $156 million increased by $2 million related to the reconciliation of 2011 actual costs for a net revenue requirement of $158 million. The decrease in the revenue requirement was primarily driven by a lower allowed rate of return associated with a reduced equity ratio and reduced rate base, offset partially by higher depreciation and operating and maintenance costs. The 2013 net revenue requirement became effective June 1, 2013, and is being recovered over the period extending through May 31, 2014. The regulatory liability associated with the true-up is being amortized as the associated amounts are recovered through rates.

BGE s updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.35%, a decrease from the 8.43% included in the prior year formula update. The decrease in return was primarily due to a debt issuance in 2012 and lower interest rates on BGE s debt outstanding. As part of the FERC-approved settlement in 2006 of BGE s 2005 transmission rate case, the base rate of return on common equity for BGE s electric transmission business for new transmission projects placed in service on and after January 1, 2006 is 11.3%, inclusive of a 50 basis point incentive for participating in PJM.

FERC Transmission Complaint (Exelon and BGE). On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. BGE s formula rate includes a 10.8% base rate of return on common equity (ROE) for most investments included in its rate base and 11.3% for the remaining transmission investment (the latter of which is conditioned upon crediting the first 50 basis points of any incentive ROE adders). The parties seek a reduction in the

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base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the earliest date from which the base return on equity could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint. As of December 31, 2013, BGE cannot predict the likelihood or a reasonable estimate of the amount of a change, if any, in the allowed base return on equity, or a reasonable estimate of the refund period start date. While BGE cannot predict the outcome of this matter, if FERC orders a reduction of BGE s base return on equity to 8.7% (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the estimated annual impact would be a reduction in revenues of approximately $10 million.

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE 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 from those facilities. 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. 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 March 30, 2012, FERC issued an order on remand affirming the cost allocation in its April 2007 order. On March 22, 2013, FERC issued an order denying rehearing of its March 30, 2012 Order and made it clear that the cost allocation at issue concerns only projects approved prior to February 1, 2013. A number of entities have filed appeals of the FERC orders. ComEd, and BGE anticipate that all impacts of any rate design changes effective after December 31, 2006 and June 30, 2006, respectively, should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on their respective 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 that any rate design changes are retroactive to periods prior to January 1, 2011, however, there may be an impact on PECO s results of operations.

On October 11, 2012, the PJM Transmission Owners filed with FERC a cost allocation for new transmission facilities asking that the new cost allocation methodology apply to all transmission approved by the PJM Board on or after February 1, 2013. The proposed methodology is a hybrid methodology that would socialize 50% of the costs of new facilities at 500kV and above and double-circuit 345kV lines, and allocate the remaining 50% to direct beneficiaries. For all other facilities, the costs would be allocated to the direct beneficiaries. On March 22, 2013, FERC issued an order accepting the cost allocation with minor exceptions and requiring a compliance filing on those few issues within 120 days of the order. The compliance filing was made on July 22, 2013.

ComEd, PECO and BGE are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. ComEd, PECO and BGE will work with

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PJM to continue to evaluate the scope and timing of any required construction projects. ComEd, PECO and BGE s estimated commitments are as follows:

	Total	2014	2015	2016	2017	2018
ComEd	$ 486	$ 134	$ 173	$ 177	$ 2	$
PECO	133	32	29	40	24	8
BGE	400	42	83	95	87	93

PJM Minimum Offer Price Rule (Exelon and Generation). 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. The proceedings leading to FERC s approval of the MOPR were extensive, and there have been numerous changes to the MOPR and litigation related to it since it was originally implemented. For example, in 2011 the parties disputed numerous elements of the MOPR including: (i) the default price that should apply to bids found subject to the MOPR, (ii) the duration of the MOPR and (iii) the application of the MOPR to self-supplying capacity and state-sponsored capacity. The FERC orders approving that MOPR have been appealed to the United States Court of Appeals for the Third Circuit. A resolution of that appeal is not expected until sometime in 2014.

In May 2012 (based on the MOPR provisions the FERC approved in 2011), PJM announced the results of its capacity auction covering the delivery year ending May 31, 2016. Several new units with state-sanctioned subsidy contracts cleared in the auction at prices below the MOPR. Potentially, these states could expand such state-sanctioned subsidy programs or other states may seek to establish similar programs. Generation believed that further revisions to that MOPR were necessary to ensure that the potential to artificially reduce capacity auction prices is appropriately limited in PJM. In early December 2012, PJM filed a new MOPR for approval at the FERC, which Exelon believed would be more effective in preventing state-sanctioned subsidy contracts from artificially reducing capacity prices. Generation was actively involved in the process through which those MOPR changes were developed and supported the changes. On May 3, 2013, the FERC issued its order. While the FERC order accepted certain aspects of the proposal that Exelon supported (such as applying the MOPR to all of PJM and not just certain zones within PJM), the FERC required PJM to retain a key element of its previous MOPR structure, the unit-specific exemption, an element that Exelon had supported removing. Several entities, including two capacity suppliers that Exelon has been working with sought rehearing of that order.

In May 2013 (based on the MOPR provisions the FERC approved earlier that month), PJM announced the results of its capacity auction covering the delivery year ending May 31, 2017. Exelon is working with PJM stakeholders on several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sanctioned subsidy contracts, excessive imported capacity resources and certain limited availability demand response resources) cannot inappropriately affect capacity auction prices in PJM.

Market-Based Rates (Exelon, Generation, ComEd, PECO and BGE). Generation, ComEd, PECO and BGE 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, PECO and BGE 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, PECO or BGE has violated the terms and conditions of its tariff or the Federal Power Act. FERC is also authorized to order refunds in certain instances if it finds that the market-based rates are not just and reasonable under the Federal Power Act.

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As required by FERC s regulations, as promulgated in the Order No. 697 series, Generation, ComEd, PECO and BGE file market power analyses using the prescribed market share screens to demonstrate that Generation, ComEd, PECO and BGE qualify for market-based rates in the regions where they are selling energy, capacity, and ancillary services under market-based rate tariffs. FERC accepted the 2008 filings on September 16, 2008, January 15, 2009 and September 2, 2009 and accepted the 2009 filings on July 28, 2009, October 26, 2009, February 23, 2010 and April 30, 2010, 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. Generation, ComEd, PECO and BGE filed an updated analysis for the Northeast Region, which includes PJM, in late 2010, based on 2009 historic test period data. On June 22, 2011, FERC issued an order confirming Generation s continued authority to charge market based rates, based on Generation s most recent updated analysis filed in 2010, stating that any market power concerns are adequately addressed by PJM s monitoring and mitigation programs. On December 30, 2013, Generation, ComEd, PECO and BGE filed its updates analysis for the Northeast Region, based on 2012 historic test period data and FERC has not yet acted on the filing. Similarly, on June 29, 2012, Generation, ComEd, BGE and PECO filed their updated market power analysis for the Central Region which the FERC accepted on November 13, 2012, and on December 23, 2011, Generation filed its updated market power analysis for the Southeast Region which the FERC accepted on October 10, 2012. On December 21, 2012, Generation, ComEd, BGE and PECO filed their updated market power analysis for the SPP region, which the FERC accepted on October 8, 2013.

Reliability Pricing Model (Exelon, Generation and BGE). PJM s RPM Base Residual Auctions take place approximately 36 months ahead of the scheduled delivery year. The most recent auction for the delivery year ending May 31, 2017 occurred in May 2013.

License Renewals (Exelon and Generation). 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 current operating licenses for Limerick Units 1 and 2 expire in 2024 and 2029, respectively. In June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC s temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. The temporary storage rule (also referred to as the waste confidence decision) recognizes that licensees can safely store spent nuclear fuel at nuclear plants for up to 60 years beyond the original and renewed licensed operating life of the plants and that licensing renewal decisions do not require discussion of the environmental impact of spent fuel stored on site. In August 2012, the NRC placed a hold on issuing new or renewed operating licenses that depend on the temporary storage rule until the court s decision is addressed. In September 2012, the NRC directed NRC Staff to revise the temporary storage rule which is now not expected until October 3, 2014. Generation does not expect the NRC to issue license renewals until the end of 2014, at the earliest.

On May 29, 2013, Generation submitted applications to the NRC to extend the operating licenses of Byron Units 1 and 2 and Braidwood Units 1 and 2 by 20 years. The current operating licenses for Byron Units 1 and 2 expire in 2024 and 2026, respectively. The current operating licenses for Braidwood Units 1 and 2 expire in 2026 and 2027, respectively. Generation does not expect the NRC to issue license renewals for Byron and Braidwood until 2015 at the earliest.

On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively.

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The FERC extended the deadline to January 31, 2014 to file a water quality certification application pursuant to Section 401 of the Clean Water Act (CWA) with the MDE for Conowingo. Generation is working with stakeholders to resolve licensing issues, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. On January 30, 2014, Exelon filed a water quality certification application pursuant to Section 401 of the CWA with MDE for Conowingo, addressing these and other issues, although Generation cannot currently predict the conditions that ultimately may be imposed. Resolution of these issues relating to Conowingo may have a material effect on Generation s results of operations and financial position through an increase in capital expenditures and operating costs.

On August 29, 2013, Exelon filed a water quality certification application pursuant to Section 401 of the CWA with PA DEP for Muddy Run, addressing these and other issues that included certain commitments made by Generation. The financial impact associated with these commitments is estimated to be in the range of $20 million to $30 million, and will include both an increase in capital expenditures as well as an increase in operating expenses. Exelon anticipates that the PA DEP will issue the water quality certification pursuant to Section 401 of the CWA for Muddy Run in the first quarter of 2014.

Based on the latest FERC procedural schedule, the FERC licensing process is not expected to be completed prior to the expiration of Muddy Run s current license on August 31, 2014, and the expiration of Conowingo s license on September 1, 2014. However, the stations would continue to operate under annual licenses until FERC takes action on the 46-year license applications. The stations are currently being depreciated over their useful lives, which includes the license renewal period. As of December 31, 2013, $33 million of direct costs associated with relicensing efforts have been capitalized.

Regulatory Assets and Liabilities (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE 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.

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The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of December 31, 2013 and 2012.

December 31, 2013	**Exelon**		**ComEd**		**PECO**		**BGE**	
	Current	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**
Regulatory assets								
Pension and other postretirement benefits	$ 221	$ 2,794	$	$	$	$	$	$
Deferred income taxes	10	1,459	2	65		1,317	8	77
AMI programs	5	159	5	35		58		66
AMI meter events		5				5		
Under-recovered distribution service costs	178	285	178	285				
Debt costs	12	56	9	53	3	3	1	8
Fair value of BGE long-term debt		219						
Fair value of BGE supply contract	12							
Severance	16	12	12				4	12
Asset retirement obligations	1	102	1	67		25		10
MGP remediation costs	40	212	33	178	6	33	1	1
RTO start-up costs	2		2					
Under-recovered uncollectible accounts		48		48				
Under-recovered electric universal Renewable energy	17	176	17	176				
Energy and transmission programs	53		52				1	
Deferred storm costs	3	3					3	3
Electric generation-related regulatory asset	13	30					13	30
Rate stabilization deferral	71	154					71	154
Energy efficiency and demand response programs	73	148					73	148
Merger integration costs	2	9					2	9
Other	31	39	18	26	8	7	4	6
Total regulatory assets	$ 760	$ 5,910	$ 329	$ 933	$ 17	$ 1,448	$ 181	$ 524

December 31, 2013	**Exelon**		**ComEd**		**PECO**		**BGE**	
	Current	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**
Regulatory liabilities								
Other postretirement benefits	$ 2	$ 43	$	$	$	$	$	$
Nuclear decommissioning		2,740		2,293		447		
Removal costs	99	1,423	78	1,219			21	204
Energy efficiency and demand response programs	53		45		8			
DLC program costs	1	10			1	10		
Energy efficiency phase II		21				21		
Electric distribution tax repairs	20	114			20	114		
Gas distribution tax repairs	8	37			8	37		
Energy and transmission programs	78		9		58		11	
Over-recovered gas and electric universal service fund costs	8				8			
Revenue subject to refund	38		38					
Over-recovered electric and gas revenue decoupling	16						16	
Other	4				3			
Total regulatory liabilities	$ 327	$ 4,388	$ 170	$ 3,512	$ 106	$ 629	$ 48	$ 204

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

December 31, 2012	**Exelon**		**ComEd**		**PECO**		**BGE**	
	Current	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**
Regulatory assets								
Pension and other postretirement benefits	$ 304	$ 3,673	$	$	$	$	$	$
Deferred income taxes	14	1,382	5	62		1,255	9	65
AMI programs	3	70	3	10		29		31
AMI meter events		17				17		
Under-recovered distribution service costs	18	191	18	191				
Debt costs	14	68	11	62	3	6	1	9
Fair value of BGE long-term debt		256						
Fair value of BGE supply contracts	77	12						
Severance	29	28	25	12			4	16
Asset retirement obligations		90		65		25		
MGP remediation costs	58	232	51	197	6	33	1	2
RTO start-up costs	3	2	3	2				
Under-recovered electric universal service fund costs	11				11			
Financial swap with Generation			226					
Renewable energy	18	49	18	49				
Energy and transmission programs	43		14		1		28	
DSP Program costs	1	3			1	3		
DSP II Program costs	1	2			1	2		
Deferred storm costs	3	6					3	6
Electric generation-related regulatory asset	16	40					16	40
Rate stabilization deferral	67	225					67	225
Energy efficiency and demand response programs	56	126					56	126
Under-recovered electric revenue decoupling	5						5	
Other	23	25	14	16	9	8		2
Total regulatory assets	$ 764	$ 6,497	$ 388	$ 666	$ 32	$ 1,378	$ 190	$ 522

December 31, 2012	**Exelon**		**ComEd**		**PECO**		**BGE**	
	Current	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**
Regulatory liabilities								
Nuclear decommissioning	$	$ 2,397	$	$ 2,037	$	$ 360	$	$
Removal costs	97	1,406	75	1,192			22	214
Energy efficiency and demand response programs	131		43		88			
Electric distribution tax repairs	20	132			20	132		
Gas distribution tax repairs	8	46			8	46		
Over-recovered uncollectible accounts	6		6					
Energy and transmission programs	54		6		48			
Over-recovered gas universal service fund costs	3				3			
Over-recovered AEPS costs	2				2			
Revenue subject to refund	40		40					
Over-recovered gas revenue decoupling	7						7	
Total regulatory liabilities	$ 368	$ 3,981	$ 170	$ 3,229	$ 169	$ 538	$ 29	$ 214

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Pension and other postretirement benefits. As of December 31, 2013, Exelon had regulatory assets of $3,015 million and regulatory liabilities of $45 million related to ComEd s and BGE s portion of deferred costs associated with Exelon s pension plans and ComEd s, PECO s and BGE s portion of deferred costs associated with Exelon s other postretirement benefit plans. PECO s pension regulatory recovery is based on cash contributions and is not included in the regulatory asset (liability) balances. The regulatory asset (liability) is amortized in proportion to the recognition of prior service costs (gains), transition obligations and actuarial losses (gains) attributable to Exelon s pension and other postretirement benefit plans determined by the cost recognition provisions of the authoritative guidance for pensions and postretirement benefits. ComEd, PECO and BGE will recover these costs through base rates as allowed in their most recently approved regulated rate orders. The pension and other postretirement benefit regulatory asset balance includes a regulatory asset established at the date of the merger related to BGE s portion of the deferred costs associated with legacy Constellation s pension and other postretirement benefit plans. The BGE-related regulatory asset is being amortized over a period of approximately 12 years, which generally represents the expected average remaining service period of plan participants at the date of the merger. See Note 16 Retirement Benefits for additional detail. No return is earned on Exelon s regulatory asset.

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 accelerated depreciation accounted for in accordance with the ratemaking policies of the ICC, PAPUC and MDPSC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future transmission and distribution rates. For ComEd and BGE, 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. For BGE, these additional income taxes are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC s March 2011 rate order. See Note 14 Income Taxes and Note 16 Retirement Benefits for additional information. ComEd, PECO and BGE are not earning a return on the regulatory asset in base rates.

AMI 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. As of December 31, 2013, ComEd had regulatory assets of $35 million related to accelerated depreciation costs resulting from the early retirements of non-AMI meters, which will be amortized over an average ten year period pursuant to the ICC approved AMI Deployment plan. 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, 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. The approved plan also provides for recovery of accelerated depreciation on PECO s non-AMI meter assets over a 10-year period ending December 31, 2020. For BGE, this amount represents smart grid pilot program costs as well as the incremental costs associated with implementing full deployment of a smart grid program. Pursuant to a MDPSC order, pilot program costs of $11 million were deferred in a regulatory asset, and, beginning with the MDPSC s March 2011 rate order, is earning BGE s most current authorized rate of return. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE, authorizing BGE to establish a separate regulatory asset for incremental costs incurred to implement the initiative, including the net depreciation and amortization costs associated with the meters, and an authorized rate of return on these costs, a portion of which is not recognized under GAAP until cost recovery begins. Additionally, the MDPSC order requires that BGE prove the cost-effectiveness of the entire smart grid initiative prior to seeking recovery of the costs deferred in these regulatory assets. Therefore, the commencement and timing of the amortization of these deferred costs is currently unknown. BGE s AMI regulatory asset excludes costs for non-AMI meters being replaced by AMI meters, as the MDPSC has ordered that the cost recovery for non-AMI meters will be considered in a future depreciation proceeding.

AMI Meter Events. This amount represents the remaining cost value of the original smart meters, net of accumulated depreciation, DOE reimbursements and amounts recovered from the vendor, of smart meter deployment that will no longer be used, including installation and removal costs. PECO intended to seek through regulatory rate recovery in a future filing with the PAPUC, any amounts no recovered from the vendor. PECO believed the amounts incurred for the original meters and related installation and removal costs were probable of recovery based on applicable case law and past precedent on reasonably and prudently incurred costs. As such, PECO has deferred these costs on Exelon s and PECO s Consolidated Balance Sheet. PECO will not earn a return on the recovery of these costs.

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 over recovery associated with the 2011 reconciliation was recovered through rates over a one-year period, that began in January 2013. The under recovery associated with the 2012 reconciliation will be recovered through rates over a one-year period beginning in January 2014. ComEd is earning a return on these costs. 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. As of December 31, 2013, the regulatory asset was comprised of $377 million for the annual reconciliation and $86 million related to significant one-time events. In addition to $58 million in deferred storm costs, net of amortization, the December 31, 2013 balance related to significant one-time events contains $28 million of merger and integration related costs, net of amortization, incurred as a result of the merger. As of December 31, 2012, the regulatory asset was comprised of $125 million for the annual reconciliation and $84 million related to significant one-time events. In addition to $58 million in deferred storm costs, net of amortization, the December 31, 2012 balance related to significant one-time events contains $26 million of merger and integration related costs, net of amortization, incurred as a result of the merger. See Note 4 Mergers and Acquisitions for additional information.

Debt costs. Consistent with rate recovery for ratemaking purposes, ComEd s, PECO s and BGE 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. ComEd and BGE are not earning a return on the recovery of these costs, while PECO is earning a return on the premium of the cost of the reacquired debt through base rates.

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Fair value of BGE long-term debt. These amounts represent the regulatory asset recorded at Exelon for the difference in the fair value of the long-term debt of BGE as of the merger date based on the MDPSC practice to allow BGE to recover its debt costs through rates. Exelon is amortizing the regulatory asset and the associated fair value over the life of the underlying debt.

Fair value of BGE supply contract. These amounts represent the regulatory asset recorded at Exelon representing the fair value of BGE s supply contracts as of the close of the merger date based on the MDPSC practice to allow BGE to recover its supply contracts through rates. Exelon is amortizing the regulatory asset and the associated fair value over a period of approximately three years.

Severance. For ComEd, 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. For BGE, these costs represent deferred severance costs that BGE has previously been granted recovery of in rates. Costs include the portion of costs associated with a 2008 workforce reduction that relate to BGE s gas business which were deferred in 2009 as a regulatory asset in accordance with the MDPSC s orders in prior rate cases and are being amortized over a 5-year period that began in January 2009. Also included are costs associated with a 2010 workforce reduction that were deferred as a regulatory asset and are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC s March 2011 rate order. Finally, costs associated with the 2012 BGE voluntary workforce reduction were deferred in 2012 as a regulatory asset in accordance with the MDPSC s orders in prior rate cases and are being amortized over a 5-year period that began in July 2012. BGE is earning a regulated return on the regulatory asset included in base rates.

Asset retirement obligations. These costs represent future legally required removal costs associated with 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 and BGE will recover these costs through future depreciation rates and will earn a return on these costs once the removal activities have been performed. See Note 15 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. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. 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. For BGE, $5 million of clean-up costs incurred during the period from July 2000 through November 2005 and an additional $1 million from December 2005 through November 2010 are recoverable through rates in accordance with MDPSC orders. These costs are being amortized over 10-year periods that began in January 2006 and December 2010, respectively. BGE is earning a return on this regulatory asset. See Note 22 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 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

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Combined Notes to Consolidated Financial Statements (Continued)

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enrolled in assistance programs. As of December 31, 2013, PECO was over-recovered for both its electric and gas programs. PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers.

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 expired 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 were recorded by ComEd as well as an offsetting regulatory asset or liability. ComEd did not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position was 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 was eliminated.

Renewable Energy. 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. Delivery under the contracts began in June 2012. Since the swap contracts were 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.

Energy and transmission programs. 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. In addition, beginning in 2013, the deferred DSP I and II Program costs are presented on a net basis with PECO s GSA under (over)-recovered energy costs. 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, 2013, PECO had a regulatory liability that included the over-recovered electric transmission costs of $8 million, $34 million related to the DSP program and $16 million related to over-recovered natural gas supply costs under the PGC. As of December 31, 2012, PECO had a regulatory asset related to under-recovered transmission costs of $1 million and a regulatory liability that included $47 million related to over-recovered electric supply costs under the GSA and $1 million related to over-recovered natural gas supply costs under the PGC. The BGE energy costs represent the electric and gas supply related costs recoverable (refundable) from (to) customers under BGE s market-based SOS and MBR programs, respectively. BGE does not earn or pay interest on under- or over-recovered costs to customers. As of December 31, 2013, BGE had a regulatory asset of $1 million related to under-recovered electric supply costs and a regulatory liability of $11 million related to over-recovered natural gas supply costs. As of December 31, 2012, BGE had a regulatory asset of $9 million related to under-recovered electric supply costs and a regulatory asset of $19 million related to under-recovered natural gas supply costs.

DSP Program costs. These amounts represent recoverable administrative costs incurred relating to filing, procurement, and information technology improvements associated with PECO s PAPUC-

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

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, that began 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 that began January 1, 2011. PECO earns a return on the recovery of information technology costs. Beginning in 2013, these costs are included within the energy and transmission programs line item.

DSP II Program Costs. These amounts represent recoverable administrative costs incurred relating to the filing and procurement associated with PECO s second PAPUC-approved DSP program for the procurement of electric supply. The filing and procurement of this DSP Program are recoverable through the GSA over its 24-month term, that began June 1, 2013. The independent evaluator costs associated with conducting procurements are recoverable over a 12-month period after the PAPUC approves the results of the procurements. PECO is not earning a return on these costs. Beginning in 2013, these costs are included within the energy and transmission programs line item.

Deferred storm costs. In the MDPSC s March 2011 rate order, BGE was authorized to defer $16 million in storm costs incurred in February 2010. These costs are being amortized over a 5-year period that began in December 2010. BGE is earning a return on this regulatory asset.

Electric generation-related regulatory asset. As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities and established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules. The portion of this regulatory asset that does not earn a regulated rate of return were $37 million as of December 31, 2013, and $47 million as of December 31, 2012. BGE will continue to amortize this amount through 2017.

Rate stabilization deferral. In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006, to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006, to May 31, 2007. In addition, as required by Senate Bill 1, the MDPSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007, to January 1, 2008. During 2007, BGE deferred $306 million of electricity purchased for resale expenses and certain applicable carrying charges, which are calculated using the implied interest rates of the rate stabilization bonds, as a regulatory asset related to the rate stabilization plans. During 2013 and 2012, BGE recovered $66 million and $67 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007.

Energy efficiency and demand response programs. These amounts represent costs recoverable (refundable) under ComEd s ICC approved Energy Efficiency and Demand Response Plan, PECO s PAPUC-approved EE&C Plan, and the BGE Smart Energy Savers Program®. ComEd

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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. For PECO, this amount represents an over-collection of program costs related to both Phase I and Phase II of its EE&C Plan. PECO does not earn (pay) interest on under (over) collections. PECO began recovering the costs of its Phase I and Phase II EE&C Plans through a surcharge in January 2010 and June 2013, respectively, based on projected spending under the programs. Phase I recovery continued over the life of the program, which expired on May 31, 2013 and excess funds collected began being refunded in June 2013. Phase II of the program began on June 1, 2013, and will continue over the life of the program, which will expire on May 31, 2016. Excess funds collected are required to be refunded beginning in June 2016. PECO earned a return on the capital investment incurred under Phase I of the program. BGE s Smart Energy Savers Program® includes both MDPSC approved demand response and energy efficiency programs. For the BGE Peak Rewards℠ demand response program which began in January 2008, actual marketing and customer bonus costs incurred in the demand response program are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the MDPSC. Fixed assets related to the demand response program are recovered over the life of the equipment. Also included in the demand response program are customer bill credits related to BGE s Smart Energy Rewards program which began in July 2013. Actual costs incurred in the conservation program are being amortized over a 5-year period with recovery beginning in 2010 pursuant to an order by the MDPSC. BGE earns a rate of return on the capital investments and deferred costs incurred under the program and earns (pays) interest on under (over) collections.

Merger integration costs. These amounts represent integration costs to achieve distribution synergies related to the merger transaction. As a result of the MDPSC s February 2013 rate order, BGE deferred $8 million related to non-severance merger integration costs incurred during 2012 and the first quarter of 2013. Of these costs, $4 million was authorized to be amortized over a 5-year period that began in March 2013. The recovery of the remaining $4 million was deferred. In the MDPSC s December 2013 rate order, BGE was authorized to recover the remaining $4 million and an additional $4 million of non-severance merger integration costs incurred during 2013. These costs are being amortized over a 5-year period that began in December 2013. BGE is earning a return on this regulatory asset included in base rates.

Under (Over)-recovered electric and gas revenue decoupling. These amounts represent the electric and gas distribution costs recoverable from or refundable to customers under BGE s decoupling mechanism, which does not earn a rate of return. As of December 31, 2013, BGE had a regulatory liability of $7 million related to over-recovered electric revenue decoupling and $9 million related to over-recovered natural gas revenue decoupling. As of December 31, 2012, BGE had a regulatory asset of $5 million related to under-recovered electric revenue decoupling and a regulatory liability of $7 million related to over-recovered natural gas revenue decoupling.

Nuclear decommissioning. These amounts represent estimated future nuclear decommissioning costs for former ComEd and PECO plants 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 be sufficient to fund the associated future decommissioning costs at the time of decommissioning. See Note 15 Asset Retirement Obligations for additional information.

Removal costs. These amounts represent funds ComEd and BGE have received from customers through depreciation rates to cover the future non-legally required cost of removal of property, plant

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and equipment which reduces rate base for ratemaking purposes. This liability is reduced as costs are incurred.

DLC Program Costs. The DLC program costs include equipment, installation, and information technology costs necessary to implement the DLC Program under PECO s EE&C Phase I Plans. PECO received full cost recovery through Phase I collections and will amortize the costs as a credit to the income statement to offset the related depreciation expense during the same period through September 2025, which is the remaining useful life of the assets. PECO is not paying interest on these over-recovered costs.

Electric distribution tax repairs. PECO s 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 began being reflected in customer bills on January 1, 2012. No interest will be paid to customers.

Gas distribution tax repairs. PECO s 2010 natural gas distribution rate case settlement required that the expected cash benefit from the application of new tax repairs deduction methodologies for 2010 and prior tax years be refunded to customers over a seven-year period. In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. Credits began being reflected in customer bills on January 1, 2013. No interest will be paid to customers.

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 or paying interest on these under (over)-recovered costs.

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. Beginning in 2013, these costs are included within the energy and transmission programs line item.

Revenue subject to refund. These amounts represent refunds of $37 million and associated interest of $1 million ComEd owes to customers primarily related to the treatment of post-test year accumulated depreciation issue in the 2007 Rate Case. See above discussion of the 2007 Rate Case for further information.

Purchase of Receivables Programs (Exelon, ComEd, PECO, and BGE)

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities consolidated billing, ComEd, PECO and BGE must purchase their customer accounts receivables. ComEd purchases receivables at

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a discount to primarily recover uncollectible accounts expense from the suppliers. BGE s tariff provides that receivables are to be purchased at a discount, primarily to recover uncollectible accounts expense from the suppliers. However, if the discount rate is negative, the tariff provides that the receivable is purchased at a zero discount rate. BGE is currently purchasing certain receivables at a zero discount rate. PECO is required to purchase receivables at face value and is permitted to recover uncollectible accounts expense from customers through distribution rates. Exelon, ComEd, PECO, and BGE do not record unbilled commodity receivables under their POR programs. Purchased billed receivables are classified in other accounts receivable, net on Exelon s, ComEd s, PECO s and BGE s Consolidated Balance Sheets. The following tables provide information about the purchased receivables of the Registrants as of December 31, 2013 and 2012.

As of December 31, 2013	**Exelon**	**ComEd**	**PECO**	**BGE**
Purchased receivables [(a)]	$ 263	$ 105	$ 72	$ 86
Allowance for uncollectible accounts [(b)]	(30)	(16)	(7)	(7)
Purchased receivables, net	$ 233	$ 89	$ 65	$ 79

As of December 31, 2012	**Exelon**	**ComEd**	**PECO**	**BGE**
Purchased receivables [(a)]	$ 191	$ 55	$ 65	$ 71
Allowance for uncollectible accounts [(b)]	(21)	(9)	(6)	(6)
Purchased receivables, net	$ 170	$ 46	$ 59	$ 65

(a) PECO s gas POR program became effective on January 1, 2012 and includes a 1% discount on purchased receivables in order to recover the implementation costs of the program. If the costs are not fully recovered when PECO files its next gas distribution rate case, PECO will propose a mechanism to recover the remaining implementation costs as a distribution charge to low volume transportation customers or apply future discounts on purchased receivables from natural gas suppliers serving those customers.

(b) For ComEd and BGE, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing (PORCB) tariff.

4. Merger and Acquisitions

Merger with Constellation (Exelon, Generation, ComEd, PECO and BGE)

Description of Transaction

On March 12, 2012, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation s interest in RF HoldCo LLC, which holds Constellation s interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon s interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including those with generation and customer supply operations that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger.

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Regulatory Matters

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion.

The following costs were recognized after the closing of the merger and are included in Exelon s, Generation s and BGE s Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2012.

Description	Payment Period	BGE	Generation	Exelon	Statement of Operations Location
BGE rate credit of $100 per residential customer [(a)]	Q2 2012	$ 113	$	$ 113	Revenues
Customer investment fund to invest in energy efficiency and low-income energy assistance to BGE customers	2012 to 2014			113.5	O&M Expense
Contribution for renewable energy, energy efficiency or related projects in Baltimore	2012 to 2014			2	O&M Expense
Charitable contributions at $7 million per year for 10 years	2012 to 2021	28	35	70	O&M Expense
State funding for offshore wind development projects	Q2 2012			32	O&M Expense
Miscellaneous tax benefits	Q2 2012	(2)		(2)	Taxes Other Than Income
Total		$ 139	$ 35	$ 328.5	

(a) Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

The direct investment estimate includes $95 million to $120 million relating to the construction of a headquarters building in Baltimore for Generation s competitive energy businesses. On March 20, 2013, Generation signed a 20 year lease agreement that is contingent upon the developer obtaining all required approvals, permits and financing for the construction of the building. Once required approvals are received and financing conditions are met, construction will commence and the building is expected to be ready for occupancy in approximately 2 years after building construction commences.

The direct investment estimate also includes $600 million to $650 million for Exelon s and Generation s commitment to develop or assist in development of 285 300 MWs of new generation in Maryland, expected to be completed over a period of 10 years. The MDPSC Order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets and, therefore, will be primarily capital in nature and recognized as incurred. If in the future Exelon determines that it is probable that it will make subsidy, compliance or liquidated damages payments related to the new generation development commitments, Exelon will record a liability at that time. As of December 31, 2013, it is reasonably possible that Exelon will be required to make subsidy or

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liquidated damages payments of approximately $40 million rather than build one of the generation projects contemplated by the commitments, given that the generation build is dependent upon the passage of legislation and other conditions that Exelon does not control.

On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland site with 120MW of new natural gas-fired generation to satisfy certain of these commitments and achievement of commercial operation is expected in 2015. In December 2013, Generation acquired the Fourmile Ridge Project in western Maryland and executed a wind turbine supply agreement for construction of a 32.5 MW project targeted for commercial operation in November 2014. This project will satisfy a portion of the 125 MW Tier I land-based renewables commitment. See Note 22 Commitments and Contingencies for additional information. As of December 31, 2013, amounts reflected in the Exelon and Generation consolidated financial statements include $24 million of capital expenditures and $6 million of development costs included within operating and maintenance expense associated with pursuit of these commitments for new generation in the State of Maryland.

Associated with certain of the regulatory approvals required for the merger, on November 30, 2012, a subsidiary of Generation sold three Maryland generating stations and associated assets, Brandon Shores and H.A. Wagner in Anne Arundel County, Maryland, and C.P. Crane in Baltimore County, Maryland, to Raven Power Holdings LLC (Raven Power), a subsidiary of Riverstone Holdings LLC. The sale agreement included a base price with purchase price adjustments based on fuel inventory, working capital, capital expenditures, and timing of the closing, resulting in net proceeds from the sale of approximately $371 million. Decisions by certain market participants to remove themselves from the bidding process, combined with the deadlines and limitations on the pool of potential buyers imposed by the merger approval orders, resulted in realized sales proceeds below Generation s estimated fair value of the Maryland generating stations. Consequently, Exelon and Generation recorded a pre-tax loss of $272 million in 2012 to reflect the difference between the sales price and the carrying value of the generating stations and associated assets. In the first quarter of 2013, Exelon and Generation recorded a pre-tax gain of $8 million to reflect the final settlement of the sales price with Raven Power.

In connection with the sale of the Maryland generating stations, Exelon agreed to indemnify Raven Power for certain costs associated with the treatment of hazardous substances at off-site disposal facilities and any claims arising as a result of, or in connection with, any toxic tort, natural resource damages, loss of life or injury to persons due to releases of, or exposure to hazardous substances in connection with Raven Power s remediation of environmental contamination or Exelon s non-compliance with environmental laws or permits prior to the closing date of the sale.

Pursuant to the MDPSC merger approval conditions, BGE is restricted from paying any dividend on its common shares through the end of 2014, was required to maintain specified minimum capital and O&M expenditure levels in 2012 and 2013, and is not permitted to reduce employment levels due to involuntary attrition associated with the merger integration process for two years following the closing of the merger. Additionally, BGE is subject to other merger approval conditions to enhance BGE s ring-fencing measures established by order of the MDPSC.

Subsequent to the merger, Generation discovered that, for the first two weeks following the merger, due to a software error, Generation inadvertently bid certain generating units into the PJM energy market at prices that slightly exceeded the cost-based caps to which it had agreed. This error was a violation of the commitments made in connection with merger approvals by DOJ, FERC and the MDPSC. Generation reported the error to the DOJ, FERC and the MDPSC and committed to remedy

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the impacts of its error. The MDPSC held a hearing to review the error, and accepted Generation s proposed remediation. Subsequent close examination by Generation of its cost-based bids also revealed the need for some minor adjustments to the cost build up for certain of its PJM units. Generation has coordinated with PJM to determine the impact on Generation s revenues and the market from this error and these adjustments, and Generation has worked with PJM to reverse the financial impacts. In November 2012, Generation reached a settlement with the DOJ regarding this matter. The final resolution did not have a material impact on Exelon s or Generation s results of operations, cash flows or financial position.

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 was disclosed and sought rescission of the proposed merger. During the third quarter of 2011, the parties to the suits reached an agreement in principle to settle the suits through additional disclosures to Constellation shareholders. On June 26, 2012, the court approved the settlement and entered final judgment.

Accounting for the Merger Transaction

The fair value of Constellation s non-regulated business assets acquired and liabilities assumed was determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The financial statements of BGE do not include fair value adjustments for assets or liabilities subject to rate-setting provisions for BGE. BGE is subject to the rate-setting authority of FERC and the MDPSC and is accounted for pursuant to the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for BGE provide revenue derived from costs including a return on investment of assets and liabilities included in rate base. Except for debt, fuel supply contracts and regulatory assets not earning a return, the fair values of BGE s tangible and intangible assets and liabilities subject to these rate-setting provisions are assumed to approximate their carrying values and, therefore, do not reflect any net adjustments related to these amounts. For BGE s debt, fuel supply contracts and regulatory assets not earning a return, the difference between fair value and book value of BGE s assets acquired and liabilities assumed is recorded as a regulatory asset and liability at Exelon Corporate as Exelon did not apply push-down accounting to BGE. See Note 1 Significant Accounting Policies for additional information on BGE s push-down accounting treatment. Also see Note 3 Regulatory Matters for additional information on BGE s regulatory assets.

The preliminary valuations performed in the first quarter of 2012 were updated in the second, third and fourth quarters of 2012, with the most significant adjustments to the preliminary valuation amounts having been made to the fair values assigned to the acquired power supply and fuel contracts, unregulated property, plant and equipment and investments in affiliates. There were no significant adjustments to the purchase price allocation in the first quarter of 2013 and the purchase price allocation was final as of March 31, 2013.

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The final purchase price allocation of the Merger of Exelon with Constellation and Exelon s contribution of certain subsidiaries of Constellation to Generation was as follows:

Preliminary Purchase Price Allocation, excluding amortization	**Exelon**	**Generation**
Current assets	$ 4,936	$ 3,638
Property, plant and equipment	9,342	4,054
Unamortized energy contracts	3,218	3,218
Other intangibles, trade name and retail relationships	457	457
Investment in affiliates	1,942	1,942
Pension and OPEB regulatory asset	740	
Other assets	2,265	1,266
Total assets	22,900	14,575
Current liabilities	3,408	2,804
Unamortized energy contracts	1,722	1,512
Long-term debt, including current maturities	5,632	2,972
Non-controlling interest	90	90
Deferred credits and other liabilities and preferred securities	4,683	1,933
Total liabilities, preferred securities and non-controlling interest	15,535	9,311
Total purchase price	$ 7,365	$ 5,264

Intangible Assets Recorded

For the power supply and fuel contracts acquired from Constellation, the difference between the contract price and the market price at the date of the merger was recognized as either an intangible asset or liability based on whether the contracts were in or out-of-the-money. The valuation of the acquired intangible assets and liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power and fuel prices and the discount rate. The fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the merger date. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues.

Exelon and Generation present separately in their Consolidated Balance Sheets the unamortized energy contract assets and liabilities for these contracts. Generation s amortization expense for the year ended December 31, 2013 amounted to $470 million. Generation s amortization expense for the period March 12, 2012 to December 31, 2012 amounted to $1,101 million. In addition, Exelon Corporate has established a regulatory asset and an unamortized energy contract liability related to BGE s power supply and fuel contracts. The power supply and fuel contracts regulatory asset amortization was $77 million for the year ended December 31, 2013 and $116 million for the period March 12, 2012 to December 31, 2012. An equally offsetting amortization of the unamortized energy contract liability has been recorded at Exelon Corporate in the Consolidated Statement of Operations.

The fair value of the Constellation trade name intangible asset was determined based on the relief from royalty method of the income approach whereby fair value is determined to be the present value of the license fees avoided by owning the assets. The measure is based upon certain unobservable

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inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the hypothetical royalty rate and the discount rate. Exelon s and Generation s straight line amortization expense for the fair value of the Constellation trade name intangible asset for the year ended December 31, 2013 and for the period March 12, 2012 to December 31, 2012 amounted to $26 million and $20 million, respectively. The trade name intangible asset is included in deferred debits and other assets within Exelon s and Generation s Consolidated Balance Sheets.

The fair value of the retail relationships was determined based on a multi-period excess method of the income approach. Under this method, the intangible asset s fair value is determined to be the estimated future cash flows that will be earned on the current customer base, taking into account expected contract renewals based on customer attrition rates and costs to retain those customers. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the customer attrition rate and the discount rate. The intangible assets for the fair value of the retail relationships are amortized as amortization expense on a straight line basis over the useful life of the underlying assets. Exelon s and Generation s straight line amortization expense for year ended December 31, 2013 and for the period March 12, 2012 to December 31, 2012 amounted to $21 million and $15 million, respectively. The retail relationships intangible assets are included in deferred debits and other assets within Exelon s and Generation s Consolidated Balance Sheets.

Exelon s intangible assets and liabilities acquired through the merger with Constellation included in its Consolidated Balance Sheets, along with the future estimated amortization, were as follows as of December 31, 2013:

					Estimated amortization expense					
Description	**Weighted Average Amortization (Years) [b]**	**Gross**	**Accumulated Amortization**	**Net**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019 and Beyond**
Unamortized energy contracts, net [a]	1.5	$ 1,499	$ (1,378)	$ 121	$ 75	$ 18	$ (31)	$ (21)	$ 11	$ 69
Trade name	10.0	243	(46)	197	24	24	24	24	24	77
Retail relationships	12.4	214	(36)	178	19	18	18	18	18	87
Total, net		$ 1,956	$ (1,460)	$ 496	$ 118	$ 60	$ 11	$ 21	$ 53	$ 233

(a) Includes the fair value of BGE s power and gas supply contracts of $12 million for which an offsetting Exelon Corporate regulatory asset was also recorded.
(b) Weighted average amortization period was calculated as of the date of acquisition.

Impact of Merger

It is impracticable to determine the overall financial statement impact for the Constellation subsidiaries contributed down to Generation following the Upstream Merger for the year ended December 31, 2012. Upon closing of the merger, the operations of these Constellation subsidiaries were integrated into Generation s operations and are therefore not fully distinguishable after the merger.

The impact of BGE on Exelon s Consolidated Statement of Operations and Comprehensive Income includes operating revenues of $3,065 million and $2,091 million and net income (loss) of $210 million and $(31) million during the years ended December 31, 2013 and December 31, 2012, respectively.

During the year ended December 31, 2013, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $142 million, $106 million, $16 million, $9 million and $6 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $17 million, $11 million and $6

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million, respectively, as a regulatory asset as of December 31, 2013. Additionally, Exelon and BGE established a regulatory asset of $6 million as of December 31, 2013 for previously incurred 2012 merger and integration-related costs.

During the year ended December 31, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $804 million, $340 million, $41 million, $17 million and $182 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $58 million, $36 million and $22 million, respectively, as a regulatory asset as of December 31, 2012.

The costs incurred are classified primarily within Operating and Maintenance Expense in the Registrants respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the BGE customer rate credit and the credit facility fees, which are included as a reduction to operating revenues and other, net, respectively, for years ended December 31, 2013 and 2012. See Note 22 Commitments and Contingencies for additional information.

Pro-forma Impact of the Merger

The following unaudited pro forma financial information reflects the consolidated results of operations of Exelon and Generation as if the merger with Constellation had taken place on January 1, 2011. The unaudited pro forma information was calculated after applying Exelon s and Generation s accounting policies and adjusting Constellation s results to reflect purchase accounting adjustments.

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

	Generation Year Ended December 31,		Exelon Year Ended December 31,	
(unaudited)	**2012**	**2011 (a)**	**2012**	**2011 (b)**
Total Revenues	$ 17,013	$ 19,494	$ 26,700	$ 30,712
Net income attributable to Exelon	1,205	324	2,092	974
Basic Earnings Per Share	n.a.	n.a.	$ 2.56	$ 1.15
Diluted Earnings Per Share	n.a.	n.a.	2.55	1.14

(a) The amounts above include non-recurring costs directly related to the merger of $203 million for the year ended December 31, 2011.
(b) The amounts above include non-recurring costs directly related to the merger of $236 million for the year ended December 31, 2011.

Acquisitions (Exelon and Generation)

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; and 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.

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

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 year ended December 31, 2011:

	Acquisitions 2011	
	Wolf Hollow	**Antelope Valley**
Fair value of consideration transferred		
Cash	$ 305	$ 75
Plus: Gain on PPA settlement	6	
Total fair value of consideration transferred	$ 311	$ 75
Recognized amounts of identifiable assets acquired and liabilities assumed		
Property, plant and equipment	$ 347	$ 15
Inventory	5	
Intangible assets [(a)]		190
Payable to First Solar, Inc. [(b)]		(135)
Working capital, net	(5)	
Other Assets		5
Total net identifiable assets	$ 347	$ 75
Bargain purchase gain	$ 36	$

(a) See Note 10 Intangible Assets for additional information.

(b) 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. At December 31, 2012, $87 million remained payable to First Solar, Inc. During 2013, a subsidiary of Generation paid off the remaining balance of the payable to First Solar, Inc.

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, for a purchase price of $311 million which increased Generation s owned capacity within the ERCOT power market by 720 MWs. The acquisition supports the Exelon commitment to low-carbon generation as part of Exelon 2020.

Generation recognized an approximately $36 million non-cash bargain purchase gain (i.e., negative goodwill). The gain was included within Other, net in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

The pro forma impact of this acquisition would not have been material to Exelon s or Generation s results of operations for the year ended December 31, 2011.

Antelope Valley Solar Ranch One. On September 30, 2011, Generation announced the completion of its acquisition of all of the interests in Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar PV project under development in northern Los Angeles County, California, from First Solar, Inc., which is developing, building, operating, and maintaining the project. The first

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portion of the project began operations in December 2012, with six additional blocks coming online in 2013. Exelon has been informed by First Solar of issues relating to delays in the certification of certain components relating to the final two blocks of the project, which will delay commercial operation of these two blocks until the first half of 2014. 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. The acquisition supports Exelon s commitment to renewable energy as part of Exelon 2020.

Exelon expects to invest up to $650 million in equity in the project through 2014. 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. See Note 13 Debt and Credit Agreements for additional information on the DOE loan guarantee.

The pro forma impact of this acquisition would not have been material to Exelon s or Generation s results of operations for the year ended December 31, 2011.

5. Investment in Constellation Energy Nuclear Group, LLC (Exelon and Generation)

As a result of the Constellation merger, Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation s total equity in earnings (losses) on the investment in CENG is as follows:

	Year Ended December 31, 2013	Period March 12, through December 31, 2012
Equity investment income	$ 123	$ 73
Amortization of basis difference in CENG	(114)	(172)
Total equity in earnings (losses) CENG	$ 9	$ (99)

As of March 12, 2012, Generation had an initial basis difference of approximately $204 million between the initial carrying value of its investment in CENG and its underlying equity in CENG. This basis difference resulted from the requirement to record the investment in CENG at fair value under purchase accounting while the underlying assets and liabilities within CENG continue to be accounted for on a historical cost basis. Generation is amortizing this basis difference over the respective useful lives of the assets and liabilities of CENG or as those assets and liabilities affect the earnings of CENG.

Based on tax sharing provisions contained in the operating agreement for CENG, Generation may be eligible for distributions from its investment in CENG in excess of its 50.01% ownership interest. Through purchase accounting, Generation has recorded the fair value of expected future distributions. When these distributions are realized, Generation will record a reduction in its investment in CENG. Any distributions in excess of Generation s investment in CENG would be recorded in earnings.

Generation has various agreements with CENG to purchase power and to provide certain services. For further information regarding these agreements see Note 25 Related Party Transactions.

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

On July 29, 2013, Exelon, Generation and subsidiaries of Generation entered into a Master Agreement with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG. The Master Agreement contemplates that the parties will execute a series of additional agreements at a closing that will occur following the receipt of regulatory approvals and the satisfaction of other customary closing conditions. Exelon currently expects that the closing will occur early in the second quarter of 2014.

The Master Agreement requires CENG to make two pre-closing cash distributions to EDF and Generation, if CENG has cash in excess of reserves and the amount of an outstanding credit facility are available, through one of its wholly owned subsidiaries, as owners of the joint venture. Generation received the first distribution of $115 million in December 2013 and recorded it as a reduction to the Investment in CENG on Exelon s and Generation s Consolidated Balance Sheets. A second distribution will occur prior to the closing provided that CENG has sufficient available cash.

At the closing, Generation, CENG and subsidiaries of CENG will execute a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDFI s rights as a member of CENG. CENG will reimburse Generation for its direct and allocated costs for such services. The NOSA will replace the SSA. At the closing, Nine Mile Point Nuclear Station, a subsidiary of CENG, will also assign to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with the co-owner. In addition, at the closing the PSAA will be amended and extended until the permanent cessation of power generation by the CENG generation plants.

In addition, at closing, Generation will make a $400 million loan to CENG, bearing interest at 5.25% per annum and payable out of specified available cash flows of CENG and in any event, payable upon the settlement of the Put Option Agreement discussed below, if the put option is exercised, or payable upon the maturity date of the note (which will be 20 years from the closing), whichever occurs first. Immediately following receipt of the proceeds of such loan, CENG will make a $400 million special distribution to EDFI. The parties will also execute a Fourth Amended and Restated Operating Agreement for CENG, pursuant to which, among other things, CENG will commit to make preferred distributions to Generation (after repayment of the $400 million loan) quarterly out of specified available cash flows, until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from the date of the special distribution to EDFI.

Generation and EDFI will also enter into a Put Option Agreement at closing pursuant to which EDFI will have the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. The appraisers determining fair market value of EDF s 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation s rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation s rights to other distributions. The beginning of the exercise period will be accelerated if Exelon s affiliates cease to own a majority of CENG and exercise a related right to terminate the Nuclear Operating Services Agreement. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

Also at closing, Generation will execute an Indemnity Agreement pursuant to which Generation will indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon will guarantee Generation s obligations under this indemnity.

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

Currently, Exelon and Generation account for their investment in CENG under the equity method of accounting. The transfer of the operating licenses and corresponding operational control to Exelon and Generation will result in Exelon and Generation being required to consolidate the financial position and results of operations of CENG. When that accounting change occurs, Exelon and Generation will derecognize their equity method investment in CENG and will record all assets, liabilities and the non-controlling interest in CENG at fair value on Exelon and Generation s balance sheets. Any difference between the former carrying value and newly recorded fair value at that date will be recognized as a gain or loss upon consolidation, which could be material to Exelon s and Generation s results of operations.

6. Accounts Receivable (Exelon, Generation, ComEd PECO and BGE)

Accounts receivable at December 31, 2013 and 2012 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:

2013	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Unbilled customer revenues	$1,151	$584 (a)	$201	$161	$205
Allowance for uncollectible accounts (b)	(272)	(57)	(62)	(107) (c)	(46)

2012	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Unbilled customer revenues	$1,094	$535 (a)	$213	$164	$182
Allowance for uncollectible accounts (b)	(293)	(84)	(70)	(99) (c)	(40)

(a) Represents unbilled portion of retail receivables estimated under Exelon s unbilled critical accounting policy.
(b) Includes the allowance for uncollectible accounts on customer and other accounts receivable.
(c) Includes an allowance for uncollectible accounts of $8 million and $7 million at December 31, 2013 and 2012, respectively, related to PECO s current installment plan receivables described below.

PECO Installment Plan Receivables (Exelon and PECO). 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 $19 million and $18 million as of December 31, 2013 and 2012, 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, 2013 of $18 million consists of $1 million, $4 million and $13 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2012 of $15 million consists of $1 million, $3 million and $11 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, 2013 and 2012 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.

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Accounts Receivable Agreement (Exelon and PECO). PECO was party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its accounts receivable designated under the agreement in exchange for proceeds of $210 million, which was classified as a short-term note payable on Exelon s and PECO s Consolidated Balance Sheets as of December 31, 2012. The agreement terminated on August 30, 2013 and PECO paid down the outstanding principal of $210 million. The financial institution no longer has an undivided interest in the accounts receivable designated under the agreement. As of December 31, 2012, the financial institution s undivided interest in Exelon s and PECO s gross accounts receivable was equivalent to $289 million, which represented the financial institution s interest in PECO s eligible receivables as calculated under the terms of the agreement. The agreement required PECO to maintain eligible receivables at least equivalent to the financial institution s undivided interest.

7. Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

Exelon

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

	Average Service Life (years)	2013	2012
Asset Category			
Electric transmission and distribution	5 - 90	$ 28,123	$ 26,576
Electric generation	1 - 52	20,420	19,004
Gas transportation and distribution	5 - 90	3,296	3,108
Common electric and gas	5 - 50	1,101	1,029
Nuclear fuel [(a)]	1 - 8	5,196	4,815
Construction work in progress	N/A	1,890	1,926
Other property, plant and equipment [(b)]	1 - 51	1,017	912
Total property, plant and equipment		61,043	57,370
Less: accumulated depreciation [(c)]		13,713	12,184
Property, plant and equipment, net		$ 47,330	$ 45,186

(a) Includes nuclear fuel that is in the fabrication and installation phase of $947 million and $894 million at December 31, 2013 and 2012, respectively.

(b) Includes Generation s buildings under capital lease with a net carrying value of $23 million and $20 million at December 31, 2013 and 2012, respectively. The original cost basis of the buildings was $59 million and total accumulated amortization was $36 million and $33 million as of December 31, 2013 and 2012, respectively. Also includes ComEd s buildings under capital lease with a net carrying value of $8 million and $0 million at December 31, 2013 and 2012, respectively. The original cost basis of the buildings was $8 million and total accumulated amortization was $0 million and $0 million as of December 31, 2013 and 2012, respectively. Includes land held for future use and non utility property at PECO and BGE. These balances also include capitalized acquisition, development and exploration costs related to oil and gas production activities at Generation.

(c) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $2,371 million and $2,078 million as of December 31, 2013 and 2012, respectively.

Combined Notes to Consolidated Financial Statements (Continued)

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

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	2013	2012	2011
Electric transmission and distribution	2.91%	2.76%	2.59%
Electric generation	3.35%	3.15%	3.12%
Gas	2.06%	2.03%	1.73%
Common electric and gas	7.53%	7.61%	8.05%

Generation

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

	Average Service Life (years)	2013	2012
Asset Category			
Electric generation	1 - 52	$ 20,420	$ 19,004
Nuclear fuel [(a)]	1 - 8	5,196	4,815
Construction work in progress	N/A	1,129	1,352
Other property, plant and equipment [(b)]	1 - 51	400	374
Total property, plant and equipment		27,145	25,545
Less: accumulated depreciation [(c)]		7,034	6,014
Property, plant and equipment, net		$ 20,111	$ 19,531

(a) Includes nuclear fuel that is in the fabrication and installation phase of $947 million and $894 million at December 31, 2013 and 2012, respectively.
(b) Includes buildings under capital lease with a net carrying value of $23 million and $20 million at December 31, 2013 and 2012, respectively. The original cost basis of the buildings was $59 million and total accumulated amortization was $36 million and $33 million as of December 31, 2013 and 2012, respectively. These balances also include capitalized acquisition, development and exploration costs related to oil and gas production activities.
(c) Includes accumulated amortization of nuclear fuel in the reactor core of $2,371 million and $2,078 million as of December 31, 2013 and 2012, respectively.

The annual depreciation provisions as a percentage of average service life for electric generation assets were 3.35%, 3.15% and 3.12% for the years ended December 31, 2013, 2012 and 2011, respectively.

License Renewals. Generation s depreciation provisions are based on the estimated useful lives of its generating stations, which assume the renewal of the licenses for all nuclear generating stations (except for Oyster Creek) and the hydroelectric generating stations. As a result, the receipt of license renewals has no impact on the Consolidated Statements of Operations. See Note 3 Regulatory Matters for additional information regarding license renewals.

Plant Retirements

Schuylkill Station and Riverside Station. On October 31, 2012, Generation notified PJM of its intention to permanently retire Schuylkill Generating Station Unit 1 by February 1, 2013, and Riverside Generating Station Unit 6 by June 1, 2014. Schuylkill Unit 1 is a 166 MW peaking oil unit located in

Combined Notes to Consolidated Financial Statements (Continued)

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

Philadelphia, Pennsylvania, which was placed in service in 1958. Riverside Unit 6 is a 115 MW peaking gas/kerosene unit that was placed in service in 1970, located in Baltimore, Maryland. On December 1, 2013, Generation notified PJM of its intention to permanently retire Riverside Generating Station Unit 4 by June 1, 2016. Riverside Unit 4 is a 74 MW intermediate gas unit that was placed in service in 1951 also located in Baltimore, Maryland. The units are being retired because they are no longer economic to operate due to their age, relatively high capital and operating costs and declining revenue expectations. On November 30, 2012, PJM notified Generation that it did not identify any transmission system reliability issues associated with the proposed Schuylkill Unit 1 retirement date, and as a result, Schuylkill Unit 1 was retired on January 1, 2013. On January 7, 2013 and December 23, 2013, PJM notified Generation that it did not identify any transmission system reliability issues associated with the retirements of Riverside Units 6 and 4, respectively. The early retirements will not have a material impact on Generation or Exelon s results of operations, cash flows or financial position.

Eddystone Station and Cromby Station. In December 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 May 27, 2011, the FERC approved a settlement providing for a reliability-must-run rate schedule, which defined compensation to be paid to Generation for continuing to operate Cromby Unit 2 and Eddystone Unit 2. The monthly fixed-cost recovery during the reliability-must-run period for Eddystone Unit 2 was approximately $6 million, and covered operating costs, plus a return on net assets, of the two units during the reliability-must-run period. In addition, Generation was 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 operated under the reliability-must-run agreement from June 1, 2011 until their respective retirement dates, Cromby Unit 2 on December 31, 2011 and Eddystone Unit 2 on May 31, 2012.

During the years ended December 31, 2013, 2012, and 2011, Generation incurred $1 million, $11 million, and $2 million of shut down costs reflected within Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. Expense for the write down of inventory was not material for the years ended December 31, 2013, 2012 and 2011.

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

ComEd

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

	Average Service Life (years)	2013	2012
Asset Category			
Electric transmission and distribution	5 - 75	$ 17,334	$ 16,480
Construction work in progress	N/A	456	294
Other property, plant and equipment [(a)]	50	60	50
Total property, plant and equipment		17,850	16,824
Less: accumulated depreciation		3,184	2,998
Property, plant and equipment, net		$ 14,666	$ 13,826

(a) Includes buildings under capital lease with a net carrying value of $8 million and $0 million at December 31, 2013 and 2012, respectively. The original cost basis of the buildings was $8 million and total accumulated amortization was $0 million and $0 million as of December 31, 2013 and 2012, respectively.

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 2.97%, 2.79% and 2.67% for the years ended December 31, 2013, 2012 and 2011, respectively.

PECO

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

Asset Category	Average Service Life (years)	2013	2012
Electric transmission and distribution	5 - 65	$ 6,669	$ 6,355
Gas transportation and distribution	5 - 70	1,932	1,859
Common electric and gas	5 - 50	600	568
Construction work in progress	N/A	101	76
Other property, plant and equipment [(a)]	50	17	17
Total property, plant and equipment		9,319	8,875
Less: accumulated depreciation		2,935	2,797

Property, plant and equipment, net	$ 6,384	$ 6,078

(a) Represents land held for future use and non utility property.

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	**2013**	**2012**	**2011**
Electric transmission and distribution	2.73%	2.51%	2.33%
Gas	1.79%	1.77%	1.73%
Common electric and gas	6.65%	7.54%	8.05%

Combined Notes to Consolidated Financial Statements (Continued)

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

BGE

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

	Average Service Life (years)	2013	2012
Asset Category			
Electric transmission and distribution	5 - 90	$ 6,100	$ 5,767
Gas distribution	5 -90	1,660	1,548
Common electric and gas	5 - 40	578	554
Construction work in progress	N/A	196	193
Other property, plant and equipment [(a)]	20	32	31
Total property, plant and equipment		8,566	8,093
Less: accumulated depreciation		2,702	2,595
Property, plant and equipment, net		$ 5,864	$ 5,498

(a) Represents land held for future use and non utility property.

Average Service Life Percentage by Asset Category	2013	2012	2011
Electric transmission and distribution	2.91%	2.92%	2.89%
Gas	2.36%	2.33%	2.41%
Common electric and gas	8.45%	7.68%	8.40%

See Note 1 Significant Accounting Polices for further information regarding property, plant and equipment policies and accounting for capitalized software costs for Exelon, Generation, ComEd, PECO and BGE. See Note 13 Debt and Credit Agreements for further information regarding Exelon s, ComEd s, and PECO s property, plant and equipment subject to mortgage liens.

8. Impairment of Long-Lived Assets (Exelon and Generation)

Long-Lived Assets (Exelon and Generation)

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In the third quarter of 2013, lower projected wind production and a decline in power prices suggested that the carrying value of certain wind projects may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of eleven wind projects, primarily located in West Texas and Minnesota, were less than their respective carrying values at September 30, 2013. The fair value analysis was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result, long-lived assets held and used with a carrying amount of approximately $75 million were written down to their fair value of $32 million and a pre-tax impairment charge of $43 million was recorded during the third quarter in operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations. Of the $43 million, $4 million was attributable to non-controlling interests for certain of the wind projects.

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

Nuclear Uprate Program (Exelon and Generation)

Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects. The Measurement Uncertainty Recapture (MUR) uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. Additionally, the market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. During 2013, Generation recorded a pre-tax charge to operating and maintenance expense and interest expense of approximately $111 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Like-Kind Exchange Transaction (Exelon)

Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in coal-fired generating station leases located in Georgia and Texas with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. See Note 14 Income Taxes for further information. 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 for a third-party to bid on a service contract 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. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract 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. 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.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and record an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, which takes into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates, and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contract option discussed above given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

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Based on the review performed in the second quarter of 2013, the estimated residual value of one of Exelon s direct financing leases experienced an other than temporary decline given reduced long-term energy and capacity price expectations. As a result, Exelon recorded a $14 million pre-tax impairment charge in the second quarter of 2013, which was recorded in investments and operating and maintenance expense in the Consolidated Balance Sheet and the Consolidated Statement of Operations, respectively. Changes in the assumptions described above could potentially result in future impairments of Exelon s direct financing lease investments, which could be material. Through December 31, 2013, no events have occurred that would require Exelon to review the estimated residual values of its direct financing lease investments subsequent to the review performed in the second quarter of 2013.

As of December 31, 2012, Exelon concluded that the estimated fair values of the residual values at the end of the lease terms exceeded the residual values established at the lease dates.

At December 31, 2013 and December 31, 2012, the components of the net investment in long-term leases were as follows:

	December 31, 2013	December 31, 2012
Estimated residual value of leased assets	$ 1,465	$ 1,492
Less: unearned income	767	807
Net investment in long-term leases	$ 698	$ 685

9. Jointly Owned Electric Utility Plant (Exelon, Generation, PECO and BGE)

Exelon, Generation, PECO and BGE s undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2013 and 2012 were as follows:

	Nuclear generation			Fossil fuel generation			Transmission		Other
	Quad Cities	**Peach Bottom**	**Salem (a)**	**Keystone (b)**	**Conemaugh (b)**	**Wyman**	**PA (c)**	**DE/NJ (d)**	**Other (e)**
Operator	Generation	Generation	PSEG Nuclear	GenOn	GenOn	FP&L	First Energy	PSEG	
Ownership interest	75.00%	50.00%	42.59%	41.98%	31.28%	5.89%	Various	42.55%	44.24%
Exelon s share at December 31, 2013:									
Plant (f)	$ 941	$ 883	$ 501	$ 725	$ 399	$ 3	$ 14	$ 64	$ 2
Accumulated depreciation (f)	226	326	134	268	220	3	7	34	1
Construction work in progress	27	174	24	6	121				
Exelon s share at December 31, 2012:									

Plant [f]	$ 874	$ 796	$ 494	$ 624	$ 322	$ 3	$ 13	$ 65	$ 1
Accumulated depreciation [f]	187	302	119	153	158	3	7	33	
Construction work in progress	44	115	11	10	57		1		

(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, 2013 and 2012.

(b) Generation s ownership interest in Keystone and Conemaugh has increased as a result of Exelon s merger with Constellation in 2012. See Note 4 Merger and Acquisitions for additional information.

(c) PECO and BGE own a 22% and 7% share, respectively, in 127 miles of 500 kV lines located in Pennsylvania; PECO and BGE also own a 20.7% and 10.56% share, respectively, of a 500 kV substation immediately outside of the Conemaugh fossil generating station which supplies power to the 500 kV lines including, but not limited to, the lines noted above.

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

(d) 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 including, but not limited to, the lines noted above.
(e) Generation has a 44.24% ownership interest in Merrill Creek Reservoir located in New Jersey.
(f) Excludes asset retirement costs.

Exelon s, Generation s, PECO s and BGE 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, PECO s and BGE 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 and BGE s Consolidated Statements of Operations.

10. Intangible Assets (Exelon, Generation, ComEd and PECO)

Goodwill

Exelon s and ComEd s gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2013 and 2012 were as follows:

	Gross Amount [(a)]	Accumulated Impairment Losses	Carrying Amount
Balance, January 1, 2012	$ 4,608	$ 1,983	$ 2,625
Impairment losses			
Balance, December 31, 2013	$ 4,608	$ 1,983	$ 2,625

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom (predecessor parent company of ComEd) 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 occur 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 for goodwill, a reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is tested for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available and is regularly reviewed by segment management. ComEd has a single operating segment for its combined business. There is no level below this operating segment for which discrete financial information is regularly reviewed by segment management. Therefore, ComEd s operating segment is considered its only reporting unit.

Entities assessing goodwill for impairment have the option of first 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.

If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value based test is performed. 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

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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. Any goodwill impairment charge at ComEd will affect Exelon s consolidated results of operations.

ComEd s valuation approach is based on a market participant view, pursuant to authoritative guidance for fair value measurement, and utilizes a weighted combination of a discounted cash flow analysis and a market multiples analysis. 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, projected operating and capital cash flows from ComEd s business 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.

2013 Goodwill Impairment Assessments. Management concluded the remeasurement of the like-kind exchange position and the charge to ComEd s earnings in the first quarter of 2013 triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of January 31, 2013. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

ComEd performed a quantitative assessment as of November 1, 2013, for its 2013 annual goodwill impairment assessment. The first step of the annual impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

In both the interim and annual assessments, the discounted cash flow analysis reflected Exelon s indemnity to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts related to the like-kind exchange position on ComEd s equity. While neither the interim nor the annual assessments indicated an impairment of ComEd s goodwill, certain assumptions used to estimate the fair value of ComEd are highly sensitive to changes. Adverse regulatory actions, such as early termination of EIMA, or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd s business, and the fair value of debt could potentially result in a future impairment of ComEd s goodwill, which could be material. Based on the results of the annual goodwill test performed as of November 1, 2013, the estimated fair value of ComEd would have needed to decrease by more than 10% for ComEd to fail the first step of the impairment test.

Prior Goodwill Impairment Assessments. Management concluded that the May 2012 ICC final Order in ComEd s 2011 formula rate proceeding triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of May 31, 2012. The first step of the

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interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required. ComEd performed a qualitative assessment as of November 1, 2012, for its 2012 annual goodwill impairment assessment and determined that its fair value was not more likely than not less than its carrying value. Therefore, ComEd did not perform a quantitative assessment. As part of its qualitative assessment, ComEd evaluated, among other things, management s best estimate of projected operating and capital cash flows for ComEd s business (including the impacts of the May 2012 Order) as well as changes in certain other market conditions, such as the discount rate and EBITDA multiples.

Other Intangible Assets

For discussion surrounding Exelon s and Generation s unamortized energy contracts, trade name and retail relationships recorded in conjunction with the Merger, refer to Note 4 Merger and Acquisitions.

Exelon s, Generation s and ComEd s other intangible assets, included in unamortized energy contract assets and deferred debits and other assets in their Consolidated Balance Sheets, consisted of the following as of December 31, 2013:

	Weighted Average Amortization Years [e]	Gross	Accumulated Amortization	Net	Estimated amortization expense 2014	2015	2016	2017	2018
Generation [f]									
Exelon Wind acquisition [a]	18.0	$ 224	$ (41)	$ 183	$ 14	$ 14	$ 14	$ 14	$ 14
Antelope Valley acquisition [b]	25.0	190	(4)	186	8	8	8	8	8
ComEd									
Chicago settlement 1999 agreement [c]	21.8	100	(76)	24	3	3	3	4	4
Chicago settlement 2003 agreement [d]	17.9	62	(38)	24	4	4	4	3	3
Total intangible assets		$ 576	$ (159)	$ 417	$ 29	$ 29	$ 29	$ 29	$ 29

(a) In December 2010, Generation acquired all of the equity interests of John Deere Renewables, LLC (later named Exelon Wind), adding 735 MWs of installed, operating wind capacity located in eight states.

(b) Refer to Note 4 Merger and Acquisitions 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.

(e) Weighted-average amortization period was calculated at the date of acquisition for acquired assets or settlement agreement.

(f) Excludes $67 million of other miscellaneous unamortized energy contracts that have been acquired at various points in time.

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The following table summarizes the amortization expense related to intangible assets for each of the years ended December 31, 2013, 2012 and 2011:

For the Year Ended December 31,	Exelon	Generation	ComEd
2013	$ 27	$ 20	$ 7
2012	20	13	7
2011	19	12	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. Key assumptions used in the valuation of these intangible assets include forecasted power prices and discount rates. Those measures are based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. The intangible assets are amortized as a decrease in operating revenue within Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income over the term of the underlying PPAs.

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 at the acquisition date. Generation determined that the estimated acquisition-date fair value of the intangible assets was approximately $224 million, which is recorded in unamortized energy contract assets within Exelon s and Generation s Consolidated Balance Sheets. The intangible assets are amortized on a straight-line basis over the period in which the associated contract revenues are recognized.

Antelope Valley. Upon completion of the development project, all of the output will be sold under a PPA with Pacific Gas & Electric Company. 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 is recorded in unamortized energy contract assets within Exelon s and Generation s Consolidated Balance Sheets. The fair value is amortized over the life of the contract in relation to the present value of the underlying cash flows as of the acquisition date.

Renewable Energy Credits and Alternative Energy Credits (Exelon, Generation, ComEd and PECO).

Exelon s, Generation s, ComEd s and PECO s other intangible assets, included in other current assets and other deferred debits and other assets on the Consolidated Balance Sheets, include RECs (Exelon, Generation and ComEd) and AECs (Exelon and PECO). Revenue for RECs that are part of a bundled power sale is recognized when the power is produced and delivered to the customer. As of December 31, 2013, and 2012, PECO had current AECs of $19 million and $17 million, respectively, and noncurrent AECs of $5 million and $9 million, respectively. As of December 31, 2013, and 2012, Generation had current RECs of $158 million and $61 million, respectively, and noncurrent RECs of $0 million and $45 million, respectively. As of December 31, 2013, and 2012, ComEd, had current RECs of $3 million and $4 million, respectively. See Note 3 Regulatory Matters and Note 22 Commitments and Contingencies for additional information on RECs and AECs.

Combined Notes to Consolidated Financial Statements (Continued)

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

11. Fair Value of Financial Assets and Liabilities (Exelon, Generation, ComEd, PECO and BGE)

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants short-term liabilities, long-term debt, SNF obligation, trust preferred securities (long-term debt to financing trusts or junior subordinated debentures), and preferred securities as of December 31, 2013, and 2012:

Exelon

	December 31, 2013				December 31, 2012	
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Carrying Amount	Fair Value
Short-term liabilities	$ 344	$ 3	$ 341	$	$ 214	$ 214
Long-term debt (including amounts due within one year)	19,132		18,672	1,079	18,745	20,520
Long-term debt to financing trusts	648			631	648	664
SNF obligation	1,021		790		1,020	763
Preferred securities of subsidiary					87	82

Generation

	December 31, 2013				December 31, 2012	
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Carrying Amount	Fair Value
Short-term liabilities	$ 22	$	$ 22	$	$	$
Long-term debt (including amounts due within one year)	7,729		6,586	1,062	7,483	7,849
SNF obligation	1,021		790		1,020	763

ComEd

	December 31, 2013				December 31, 2012	
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Carrying Amount	Fair Value
Short-term liabilities	$ 184	$	$ 184	$	$	$
Long-term debt (including amounts due within one year)	5,675		6,238	17	5,567	6,548
Long-term debt to financing trust	206			202	206	212

PECO

	December 31, 2013				December 31, 2012	
		Fair Value				
	Carrying Amount	Level 1	Level 2	Level 3	Carrying Amount	Fair Value
Short-term liabilities	$	$	$	$	$ 210	$ 210
Long-term debt (including amounts due within one year)	2,197		2,358		1,947	2,264
Long-term debt to financing trusts	184			180	184	188
Preferred securities					87	82

Combined Notes to Consolidated Financial Statements (Continued)

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

BGE

	December 31, 2013				December 31, 2012	
		Fair Value				
	Carrying Amount	Level 1	Level 2	Level 3	Carrying Amount	Fair Value
Short-term liabilities	$ 138	$ 3	$ 135	$	$	$
Long-term debt (including amounts due within one year)	2,011		2,148		2,178	2,468
Long-term debt to financing trusts	258			249	258	263

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of short-term borrowings (Level 2), short-term notes payable related to PECO s accounts receivable agreement (Level 2), and dividends payable (Level 1). The Registrants carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments. See Note 13 Debt and Credit Agreements for additional information on PECO s accounts receivable agreement.

Long-Term Debt. The fair value amounts of Exelon s taxable debt securities (Level 2) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the electric utility sector with similar credit ratings in both the primary and secondary market, across the Registrants debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

The fair value of Generation s non-government-backed fixed rate project financing debt (Level 3) is based on market and quoted prices for its own and other project financing debt with similar risk profiles. Given the low trading volume in the project financing debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation s government-back fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate project financing debt resets on a quarterly basis and the carrying value approximates fair value.

The Registrants also have tax-exempt debt (Level 3). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (i.e., political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above.

SNF Obligation. The carrying amount of Generation s SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation s nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation

estimated to be settled in 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation s discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

Long-Term Debt to Financing Trusts. Exelon s long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

Preferred Securities. The fair value of these securities is determined based on the last closing price prior to quarter end, less accrued interest. The securities are registered with the SEC and are public. PECO redeemed all outstanding series of preferred securities on May 1, 2013. See Note 20 Earnings Per Share and Equity for additional information.

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 the Registrants have the ability to access as of the reporting date. Financial assets and liabilities utilizing Level 1 inputs include active exchange-traded equity securities and funds, certain 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, 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 or third-party valuations 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 securities and derivatives, and investments priced using an alternative pricing mechanism or third party valuation.

Combined Notes to Consolidated Financial Statements (Continued)

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

Exelon

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, 2013 and December 31, 2012:

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [(a)]	$ 1,230	$	$	$ 1,230
Nuclear decommissioning trust fund investments				
Cash equivalents	459			459
Equity				
Individually held	1,776			1,776
Exchange traded funds	115			115
Commingled funds		2,271		2,271
Equity funds subtotal	1,891	2,271		4,162
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	882			882
Debt securities issued by states of the United States and political subdivisions of the states		294		294
Debt securities issued by foreign governments		87		87
Corporate debt securities		1,753	31	1,784
Federal agency mortgage-backed securities		10		10
Commercial mortgage-backed securities (non-agency)		40		40
Residential mortgage-backed securities (non-agency)		7		7
Mutual funds		18		18
Fixed income subtotal	882	2,209	31	3,122
Middle market lending			314	314
Private Equity			5	5
Other debt obligations		14		14
Nuclear decommissioning trust fund investments subtotal [(b)]	3,232	4,494	350	8,076
Pledged assets for Zion decommissioning				
Cash equivalents		26		26
Equity				
Individually held	16			16
Equity funds subtotal	16			16
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	45	4		49

Debt securities issued by states of the United States and political subdivisions of the states		20		20
Corporate debt securities		227		227
Fixed income subtotal	45	251		296
Middle market lending			112	112
Other debt obligations		1		1
Pledged assets for Zion decommissioning subtotal [(c)]	61	278	112	451

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Combined Notes to Consolidated Financial Statements (Continued)

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

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Rabbi trust investments				
Cash equivalents	2			2
Mutual funds [(d)(e)]	54			54
Rabbi trust investments subtotal	56			56
Commodity mark-to-market derivative assets				
Economic hedges	493	2,582	885	3,960
Proprietary trading	324	1,315	122	1,761
Effect of netting and allocation of collateral [(f)]	(863)	(3,131)	(430)	(4,424)
Commodity mark-to-market assets subtotal	(46)	766	577	1,297
Interest rate mark-to-market derivative assets	30	39		69
Effect of netting and allocation of collateral	(30)	(2)		(32)
Interest rate mark-to-market derivative assets subtotal		37		37
Other Investments			15	15
Total assets	4,533	5,575	1,054	11,162
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(540)	(1,890)	(590)	(3,020)
Proprietary trading	(328)	(1,256)	(119)	(1,703)
Effect of netting and allocation of collateral [(f)]	869	3,007	404	4,280
Commodity mark-to-market liabilities subtotal [(h)]	1	(139)	(305)	(443)
Interest rate mark-to-market derivative liabilities	(31)	(17)		(48)
Effect of netting and allocation of collateral	31	1		32
Interest rate mark-to-market derivative liabilities subtotal		(16)		(16)
Deferred compensation obligation		(114)		(114)
Total liabilities	1	(269)	(305)	(573)
Total net assets	$ 4,534	$ 5,306	$ 749	$ 10,589

Combined Notes to Consolidated Financial Statements (Continued)

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

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [(a)]	$ 995	$	$	$ 995
Nuclear decommissioning trust fund investments				
Cash equivalents	245			245
Equity				
Individually held	1,480			1,480
Commingled funds		1,933		1,933
Equity funds subtotal	1,480	1,933		3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057			1,057
Debt securities issued by states of the United States and political subdivisions of the states		321		321
Debt securities issued by foreign governments		93		93
Corporate debt securities		1,788		1,788
Federal agency mortgage-backed securities		24		24
Commercial mortgage-backed securities (non-agency)		45		45
Residential mortgage-backed securities (non-agency)		11		11
Mutual funds		23		23
Fixed income subtotal	1,057	2,305		3,362
Middle market lending			183	183
Other debt obligations		15		15
Nuclear decommissioning trust fund investments subtotal [(b)]	2,782	4,253	183	7,218
Pledged assets for Zion decommissioning				
Cash equivalents		23		23
Equity				
Individually held	14			14
Commingled funds		9		9
Equity funds subtotal	14	9		23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12		130
Debt securities issued by states of the United States and political subdivisions of the states		37		37
Corporate debt securities		249		249
Federal agency mortgage-backed securities		49		49
Commercial mortgage-backed securities (non-agency)		6		6
Fixed income subtotal	118	353		471
Middle market lending			89	89
Other debt obligations		1		1

Pledged assets for Zion decommissioning subtotal [c]	132	386	89	607
Rabbi trust investments				
Cash equivalents	2			2
Mutual funds [d][e]	69			69
Rabbi trust investments subtotal	71			71

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Combined Notes to Consolidated Financial Statements (Continued)

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

As of December 31, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity mark-to-market derivative assets				
Economic hedges	861	3,173	641	4,675
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral [(f)]	(1,823)	(4,175)	(58)	(6,056)
Commodity mark-to-market assets subtotal [(g)]	80	1,076	656	1,812
Interest rate mark-to-market derivative assets		114		114
Effect of netting and allocation of collateral		(51)		(51)
Interest rate mark-to-market derivative assets subtotal		63		63
Other Investments	2		17	19
Total assets	4,062	5,778	945	10,785
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,041)	(2,289)	(236)	(3,566)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral [(f)]	2,042	4,020	25	6,087
Commodity mark-to-market liabilities [(g)(h)]	(83)	(228)	(289)	(600)
Interest rate mark-to-market liabilities		(84)		(84)
Effect of netting and allocation of collateral		51		51
Interest rate mark-to-market derivative liabilities subtotal		(33)		(33)
Deferred compensation obligation		(102)		(102)
Total liabilities	(83)	(363)	(289)	(735)
Total net assets	$ 3,979	$ 5,415	$ 656	$ 10,050

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.

(b) Excludes net assets (liabilities) of $(5) million and $30 million at December 31, 2013 and December 31, 2012, 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 $7 million at both December 31, 2013 and December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(d) The mutual funds held by the Rabbi trusts include $53 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at December 31, 2013, and $53 million related to deferred compensation and $16 million related to Supplemental Executive Retirement Plan at December 31, 2012.

(e) Excludes $32 million and $28 million of the cash surrender value of life insurance investments at December 31, 2013 and December 31, 2012, respectively.

(f) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $6 million, $(124) million and $(26) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2013. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012.

(g) The Level 3 balance does not include current assets for Generation and current liabilities for ComEd of $226 million at December 31, 2012 related to the fair value of Generation s financial swap contract with ComEd.

(h) The Level 3 balance includes the current and noncurrent liability of $17 million and $176 million at December 31, 2013, respectively, and $18 million and $49 million at December 31, 2012, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Combined Notes to Consolidated Financial Statements (Continued)

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

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, 2013 and 2012:

For the Year Ended December 31, 2013	Nuclear Decommissioning Trust Fund Investment	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of January 1, 2013	$ 183	$ 89	$ 367	$ 17	$ 656
Total realized / unrealized gains (losses)					
Included in net income	2		(44)[(a)]		(42)
Included in other comprehensive income				2	2
Included in regulatory assets	8		(126)[(b)]		(118)
Change in collateral			7		7
Purchases, sales, issuances and settlements					
Purchases	203	62	28	4	297
Sales	(28)	(39)	(11)	(8)	(86)
Settlements	(18)				(18)
Transfers into Level 3			86 [(c)]	1	87
Transfers out of Level 3			(35)	(1)	(36)
Balance as of December 31, 2013	$ 350	$ 112	$ 272	$ 15	$ 749
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held as of December 31, 2013	$ 1	$	$ 167	$	$ 168

(a) Includes a reduction for the reclassification of $211 million of realized gains due to settlement of derivative contracts recorded in results of operations for the year ended December 31, 2013.

(b) Excludes decreases in fair value of $11 million of and realized losses reclassified due to settlements of $215 million associated with Generation s financial swap contract with ComEd for the year ended December 31, 2013. All items eliminate upon consolidation in Exelon s Consolidated Financial Statements.

(c) Includes an increase of transfers into Level 3 arising from reductions in market liquidity, which resulted in less observable contract tenures in various locations.

Combined Notes to Consolidated Financial Statements (Continued)

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

For the Year Ended December 31, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Decommissioning	Mark-to-Market Derivatives (b)	Other Investments	Total
Balance as of January 1, 2012	$ 13	$ 37	$ 17	$	$ 67
Total realized / unrealized gains (losses)					
Included in income			59[(a)]		59
Included in regulatory liabilities	1		39		40
Change in collateral			(32)		(32)
Purchases, sales, issuances and settlements					
Purchases	169	63	334[(c)]	17	583
Sales		(11)			(11)
Transfers into Level 3			39		39
Transfers out of Level 3			(89)		(89)
Balance as of December 31, 2012	$ 183	$ 89	$ 367	$ 17	$ 656
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities as of December 31, 2012	$	$	$ 214	$	$ 214

(a) Includes a reduction for the reclassification of $155 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the year ended December 31, 2012.
(b) Excludes $98 million of increases in fair value and $566 million of realized losses due to settlements for the year ended December 31, 2012 of Generation s financial swap contract with ComEd, which eliminates upon consolidation in Exelon s Consolidated Financial Statements. This position was de-designated as a cash flow hedge prior to the merger date.
(c) Includes $310 million of fair value from contracts and $14 million of other investments acquired as a result of the merger.

The following tables present the income statement classification of the 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, 2013 and 2012:

	Operating Revenue	Purchased Power and Fuel	Other, net (a)
Total gains (losses) included in income for the year ended December 31, 2013	$ (152)	$ 108	$ 2
Change in the unrealized gains relating to assets and liabilities held for the year ended December 31, 2013	$ 40	$ 127	$ 1

	Operating Revenue	Purchased Power and Fuel	Other, net
Total gains included in income for the year ended December 31, 2012	$ 54	$ 5	$
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2012	$ 230	$ (16)	$

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

Combined Notes to Consolidated Financial Statements (Continued)

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

Generation

The following tables present assets and liabilities measured and recorded at fair value on Generation s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2013 and December 31, 2012:

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 1,006	$	$	$ 1,006
Nuclear decommissioning trust fund investments				
Cash equivalents	459			459
Equity				
Individually held	1,776			1,776
Exchange traded funds	115			115
Commingled funds		2,271		2,271
Equity funds subtotal	1,891	2,271		4,162
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	882			882
Debt securities issued by states of the United States and political subdivisions of the states		294		294
Debt securities issued by foreign governments		87		87
Corporate debt securities		1,753	31	1,784
Federal agency mortgage-backed securities		10		10
Commercial mortgage-backed securities (non-agency)		40		40
Residential mortgage-backed securities (non-agency)		7		7
Mutual funds		18		18
Fixed income subtotal	882	2,209	31	3,122
Middle market lending			314	314
Private Equity			5	5
Other debt obligations		14		14
Nuclear decommissioning trust fund investments subtotal [(b)]	3,232	4,494	350	8,076
Pledged assets for Zion Station decommissioning				
Cash equivalents		26		26
Equity				
Individually held	16			16
Equity funds subtotal	16			16
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	45	4		49

Debt securities issued by states of the United States and political subdivisions of the states	20	20
Corporate debt securities	227	227

Combined Notes to Consolidated Financial Statements (Continued)

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

As of December 31, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Fixed income subtotal	45	251		296
Middle market lending			112	112
Other debt obligations		1		1
Pledged assets for Zion Station decommissioning subtotal [(c)]	61	278	112	451
Rabbi trust investments				
Mutual funds [(d)]	13			13
Rabbi trust investments subtotal	13			13
Commodity mark-to-market derivative assets				
Economic hedges	493	2,582	885	3,960
Proprietary trading	324	1,315	122	1,761
Effect of netting and allocation of collateral [(e)]	(863)	(3,131)	(430)	(4,424)
Commodity mark-to-market assets subtotal	(46)	766	577	1,297
Interest Rate mark-to-market derivative assets	30	32		62
Effect of netting and allocation of collateral	(30)	(2)		(32)
Interest Rate mark-to-market derivative assets subtotal		30		30
Other investments			15	15
Total assets	4,266	5,568	1,054	10,888
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(540)	(1,890)	(397)	(2,827)
Proprietary trading	(328)	(1,256)	(119)	(1,703)
Effect of netting and allocation of collateral [(e)]	869	3,007	404	4,280
Commodity mark-to-market liabilities subtotal	1	(139)	(112)	(250)
Interest rate mark-to-market derivative liabilities	(31)	(13)		(44)
Effect of netting and allocation of collateral	31	1		32
Interest rate mark-to-market derivative liabilities subtotal		(12)		(12)
Deferred compensation obligation		(29)		(29)
Total liabilities	1	(180)	(112)	(291)
Total net assets	$ 4,267	$ 5,388	$ 942	$ 10,597

Combined Notes to Consolidated Financial Statements (Continued)

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

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 487	$	$	$ 487
Nuclear decommissioning trust fund investments				
Cash equivalents	245			245
Equity				
Individually held	1,480			1,480
Commingled funds		1,933		1,933
Equity funds subtotal	1,480	1,933		3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057			1,057
Debt securities issued by states of the United States and political subdivisions of the states		321		321
Debt securities issued by foreign governments		93		93
Corporate debt securities		1,788		1,788
Federal agency mortgage-backed securities		24		24
Commercial mortgage-backed securities (non-agency)		45		45
Residential mortgage-backed securities (non-agency)		11		11
Mutual funds		23		23
Fixed income subtotal	1,057	2,305		3,362
Middle market lending			183	183
Other debt obligations		15		15
Nuclear decommissioning trust fund investments subtotal [b]	2,782	4,253	183	7,218
Pledged assets for Zion Station decommissioning				
Cash equivalents		23		23
Equity				
Individually held	14			14
Commingled funds		9		9
Equity funds subtotal	14	9		23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12		130
Debt securities issued by states of the United States and political subdivisions of the states		37		37
Corporate debt securities		249		249
Federal agency mortgage-backed securities		49		49
Commercial mortgage-backed securities (non-agency)		6		6
Fixed income subtotal	118	353		471
Middle market lending			89	89
Other debt obligations		1		1

Pledged assets for Zion Station decommissioning subtotal [c]	132	386	89	607
Rabbi trust investments				
Cash equivalents	1			1
Mutual funds [d]	13			13

Combined Notes to Consolidated Financial Statements (Continued)

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

As of December 31, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Rabbi trust investments subtotal	14			14
Commodity mark-to-market derivative assets				
Economic hedges	861	3,173	867	4,901
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral [(f)]	(1,823)	(4,175)	(58)	(6,056)
Commodity mark-to-market assets subtotal	80	1,076	882	2,038
Interest rate mark-to-market derivative assets		101		101
Effect of netting and allocation of collateral		(51)		(51)
Interest rate mark-to-market derivative assets subtotal		50		50
Other investments	2		17	19
Total assets	3,497	5,765	1,171	10,433
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,041)	(2,289)	(169)	(3,499)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral [(f)]	2,042	4,020	25	6,087
Commodity mark-to-market liabilities subtotal	(83)	(228)	(222)	(533)
Interest rate mark-to-market derivative liabilities		(84)		(84)
Effect of netting and allocation of collateral		51		51
Interest rate mark-to-market derivative liabilities subtotal		(33)		(33)
Deferred compensation obligation		(28)		(28)
Total liabilities	(83)	(289)	(222)	(594)
Total net assets	$ 3,414	$ 5,476	$ 949	$ 9,839

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets (liabilities) of $(5) million and $30 million at December 31, 2013 and December 31, 2012, 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 $7 million at both December 31, 2013 December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) Excludes $10 million and $8 million of the cash surrender value of life insurance investments at December 31, 2013 and December 31, 2012, respectively.
(e) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $6 million, $(124) million and $(26) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2013. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012.
(f)

The Level 3 balance includes current assets for Generation of $226 million at December 31, 2012 related to the fair value of Generation s financial swap contract with ComEd, which eliminates upon consolidation in Exelon s Consolidated Financial Statements.

Combined Notes to Consolidated Financial Statements (Continued)

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

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, 2013, and 2012:

For the Year Ended December 31, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of January 1, 2013	$ 183	$ 89	$ 660	$ 17	$ 949
Total unrealized / realized gains (losses)					
Included in income	2		(51)[(a)(b)]		(49)
Included in other comprehensive income			(219)[(b)]	2	(217)
Included in noncurrent payables to affiliates	8				8
Change in collateral			7		7
Purchases, sales, issuances and settlements					
Purchases	203	62	28	4	297
Sales	(28)	(39)	(11)	(8)	(86)
Settlements	(18)				(18)
Transfers into Level 3			86[(c)]	1	87
Transfers out of Level 3			(35)	(1)	(36)
Balance as of December 31, 2013	$ 350	$ 112	$ 465	$ 15	$ 942
The amount of total losses included in income attributed to the change in unrealized gains related to assets and liabilities held as of December 31, 2013	$ 1	$	$ 156	$	$ 157

(a) Includes a reduction for the reclassification of $207 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the year ended December 31, 2013.

(b) Includes $11 million of increases in fair value and realized losses due to settlements of $215 million associated with Generation s financial swap contract with ComEd for the year ended December 31, 2013. All items eliminate upon consolidation in Exelon s Consolidated Financial Statements.

(c) Includes an increase of transfers into Level 3 arising from reductions in market liquidity, which resulted in less observable contract tenures in various locations.

Combined Notes to Consolidated Financial Statements (Continued)

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

For the Year Ended December 31, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of January 1, 2012	$ 13	$ 37	$ 817	$	$ 867
Total realized / unrealized gains (losses)					
Included in income			66[(a)]		66
Included in other comprehensive income			(475)[(b)]		(475)
Included in noncurrent payables to affiliates	1				1
Changes in collateral			(32)		(32)
Purchases, sales, issuances and settlements					
Purchases	169	63	334[(c)]	17	583
Sales		(11)			(11)
Transfers into Level 3			39		39
Transfers out of Level 3			(89)		(89)
Balance as of December 31, 2012	$ 183	$ 89	$ 660	17	$ 949
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities as of December 31, 2012	$	$	$ 165	$	$ 165

(a) Includes a reduction for the reclassification of $99 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the year ended December 31, 2012.

(b) Includes $98 million of increases in fair value and $566 million of realized losses reclassified from OCI due to settlements associated with Generation s financial swap contract with ComEd for the year ended December 31, 2012. This position was de-designated as a cash flow hedge prior to the merger date. All prospective changes in fair value and reclassifications of realized amounts are being recorded to income offset by the amortization of the frozen mark in OCI. All items eliminate upon consolidation in Exelon s Consolidated Financial Statements.

(c) Includes $310 million of fair value from contracts and $14 million of other investments acquired as a result of the merger.

The following tables present the income statement classification of the 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, 2013, and 2012:

	Operating Revenue	Purchased Power and Fuel	Other - net [(a)]
Total gains (losses) included in income for the year ended December 31, 2013	$ (158)	$ 107	$ 2
Change in the unrealized gains relating to assets and liabilities held for the year ended December 31, 2013	$ 30	$ 126	$ 1

	Operating Revenue	Purchased Power and Fuel	Other - net [(a)]
Total gains included in income for the year ended December 31, 2012	$ 61	$ 5	$
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2012	$ 181	$ (16)	$

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Combined Notes to Consolidated Financial Statements (Continued)

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

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

ComEd

The following tables present assets and liabilities measured and recorded at fair value on ComEd s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2013 and December 31, 2012:

As of December 31, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Rabbi trust investments				
Mutual funds	5			5
Rabbi trust investments subtotal	5			5
Total assets	5			5
Liabilities				
Deferred compensation obligation		(8)		(8)
Mark-to-market derivative liabilities [b]			(193)	(193)
Total liabilities		(8)	(193)	(201)
Total net assets (liabilities)	$ 5	$ (8)	$ (193)	$ (196)

As of December 31, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 111	$	$	$ 111
Rabbi trust investments				
Mutual funds	8			8
Rabbi trust investments subtotal	8			8
Total assets	119			119
Liabilities				
Deferred compensation obligation		(8)		(8)
Mark-to-market derivative liabilities [a][b]			(293)	(293)
Total liabilities		(8)	(293)	(301)
Total net assets (liabilities)	$ 119	$ (8)	$ (293)	$ (182)

(a) The Level 3 balance includes the current liability of $226 million at December 31, 2012, related to the fair value of ComEd s financial swap contract with Generation which eliminates upon consolidation in Exelon s Consolidated Financial Statements.
(b) The Level 3 balance includes the current and noncurrent liability of $17 million and $176 million at December 31, 2013, respectively, and $18 million and $49 million at December 31, 2012, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the year ended and December 31, 2013, and 2012:

For the Year Ended December 31, 2013	**Mark-to-Market Derivatives**
Balance as of January 1, 2013	$ (293)
Total realized / unrealized gains included in regulatory assets [(a)(b)]	100
Balance as of December 31, 2013	$ (193)

(a) Includes $11 million of decreases in fair value and realized gains due to settlements of $215 million associated with ComEd s financial swap contract with Generation for the year ended December 31, 2013. All items eliminate upon consolidation in Exelon s Consolidated Financial Statements.

Combined Notes to Consolidated Financial Statements (Continued)

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

(b) Includes $133 million of increases in the fair value and realized losses due to settlements of $7 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2013.

Twelve Months Ended December 31, 2012	**Mark-to-Market Derivatives**
Balance as of January 1, 2012	$ (800)
Total realized / unrealized gains included in regulatory assets [(a)(b)]	507
Balance as of December 31, 2012	$ (293)

(a) Includes $98 million of increases in fair value and $566 million of realized gains due to settlements associated with ComEd s financial swap contract with Generation for the year ended December 31, 2012. All items eliminate upon consolidation in Exelon s Consolidated Financial Statements.

(b) Includes $34 million of decreases in the fair value and realized losses due to settlements of $5 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2012.

PECO

The following tables present assets and liabilities measured and recorded at fair value on PECO s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2013 and December 31, 2012:

As of December 31, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 175	$	$	$ 175
Rabbi trust investments				
Mutual funds [(a)]	9			9
Rabbi trust investments subtotal	9			9
Total assets	184			184
Liabilities				
Deferred compensation obligation		(17)		(17)
Total liabilities		(17)		(17)
Total net assets (liabilities)	$ 184	$ (17)	$	$ 167

As of December 31, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 346	$	$	$ 346
Rabbi trust investments				

Mutual funds [a]	9			9
Rabbi trust investments subtotal	9			9
Total assets	355			355
Liabilities				
Deferred compensation obligation		(18)		(18)
Total liabilities		(18)		(18)
Total net assets (liabilities)	$ 355	$ (18)	$	$ 337

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Combined Notes to Consolidated Financial Statements (Continued)

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

(a) Excludes $14 million and $13 million of the cash surrender value of life insurance investments at December 31, 2013 and 2012, respectively.

PECO had no Level 3 assets or liabilities measured at fair value on a recurring basis during the year ended December 31, 2013 and 2012.

BGE

The following tables present assets and liabilities measured and recorded at fair value on BGE s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2013 and December 31, 2012:

As of December 31, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 31	$	$	$ 31
Rabbi trust investments				
Mutual funds	6			6
Rabbi trust investments subtotal	6			6
Total assets	37			37
Liabilities				
Deferred compensation obligation		(6)		(6)
Total liabilities		(6)		(6)
Total net assets (liabilities)	$ 37	$ (6)	$	$ 31

As of December 31, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 33	$	$	$ 33
Rabbi trust investments				
Mutual funds	5			5
Rabbit trust investments subtotal	5			5
Total assets	38			38
Liabilities				
Deferred compensation obligation		(5)		(5)

Total liabilities		(5)		(5)
Total net assets (liabilities)	$ 38	$ (5)	$	$ 33

BGE had no Level 3 assets or liabilities measured at fair value on a recurring basis during the year ended December 31, 2013.

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.

Combined Notes to Consolidated Financial Statements (Continued)

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

Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE). The Registrants cash equivalents include investments with maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to satisfy 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 or Level 2.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained 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. The fair values of private placement fixed income securities are determined using a third party valuation that contains certain significant unobservable inputs and are categorized in Level 3.

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. 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.

Combined Notes to Consolidated Financial Statements (Continued)

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

Middle market lending are investments in loans or managed funds which invest in private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models, and income models. Investments in middle market lending 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. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Rabbi Trust Investments (Exelon, Generation, ComEd, PECO and BGE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon s executive management and directors. The investments in the Rabbi trusts are included in investments in the Registrants Consolidated Balance Sheets and consist primarily of mutual 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. Mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices.

Mark-to-Market Derivatives (Exelon, Generation, and ComEd). 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 derivatives pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants derivatives are predominately at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information 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. Such instruments are categorized in Level 3.

Transfers in and out of levels are recognized as of the end of the reporting period 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 were not material. Transfers into Level 2 from Level 3 generally occur when the contract tenure becomes more observable. Transfers into Level 3 from Level 2 generally occur due to changes in market liquidity or assumptions for certain commodity contracts.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon 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

Combined Notes to Consolidated Financial Statements (Continued)

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

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 12 Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO and BGE). The Registrants deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants deferred compensation obligations is based on the market value of the participants notional investment accounts. The notional investments are comprised primarily of mutual funds, which are based on observable market prices. However, since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd)

Mark-to-Market Derivatives (Exelon, Generation, ComEd). 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 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, corporate controller, 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 and is responsible for approving all valuation procedures at Exelon. Forward price curves for the power market utilized by the front office to manage the portfolio are reviewed and verified by the middle office and used for financial reporting by the back office. The Registrants consider 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. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding the Registrants significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and notional size. Generation s Level 3 balance generally consists of forward sales and purchases of power and natural gas, coal purchases, certain transmission congestion contracts, and project financing debt. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

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

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation s own credit quality for liabilities. The level of observability of a forward commodity price is generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are highly liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument s market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately \$3.92 and \$0.12 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for information regarding the maturity by year of the Registrant s mark-to-market derivative assets and liabilities.

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. See Note 12 Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

Combined Notes to Consolidated Financial Statements (Continued)

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

The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at December 31, 2013 [(c)]	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives Economic Hedges (Generation)[(a)]	$ 488	Discounted Cash Flow	Forward power price	$8 - $176[(d)]
			Forward gas price	$2.98 - $16.63[(d)]
		Option Model	Volatility percentage	15% - 142%
Mark-to-market derivatives Proprietary trading (Generation) [(a)]	$ 3	Discounted Cash Flow	Forward power price	$10 - $176[(d)]
		Option Model	Volatility percentage	14% - 19%
Mark-to-market derivatives (ComEd)	$ (193)	Discounted Cash Flow	Forward heat rate [(b)]	8 - 9
			Marketability reserve	3.5% - 8%
			Renewable factor	84% -128%

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract s delivery.
c) The fair values do not include cash collateral held on Level 3 positions of $26 million as of December 31, 2013.
d) The upper ends of the ranges are driven by the winter power and gas prices in the New England region. Without the New England region, the upper ends of the ranges for power and gas would be approximately $100 and $5.70, respectively.

Type of trade	Fair Value at December 31, 2012 [(d)]	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives Economic Hedges (Generation) [(a)]	$ 473	Discounted Cash Flow	Forward power price	$14 - $79
			Forward gas price	$3.26 - $6.27
		Option Model	Volatility percentage	28% - 132%
Mark-to-market derivatives Proprietary trading (Generation) [(a)]	$ (6)	Discounted Cash Flow	Forward power price	$15 - $106
		Option Model	Volatility percentage	16% - 48%
Mark-to-market derivatives Transactions with affiliates (Generation and ComEd) [(b)]	$ 226	Discounted Cash Flow	Marketability reserve	8% - 9%

Mark-to-market derivatives (ComEd)	$	(67)	Discounted Cash Flow	Forward heat rate [c]	8% - 9.5%
				Marketability reserve	3.5% - 8.3%
				Renewable factor	81% - 123%

Combined Notes to Consolidated Financial Statements (Continued)

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

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Includes current assets for Generation and current liabilities for ComEd of $226 million, related to the fair value of the five-year financial swap contract between Generation and ComEd that ended in May 2013, which eliminates in consolidation.
c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract s delivery.
d) The fair values do not include cash collateral held on Level 3 positions of $33 million as of December 31, 2012.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation s commodity derivatives are forward commodity prices and for options is volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending, certain corporate debt securities, and private equity investments the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on valuations of comparable companies, discounting the forecasted cash flows of the portfolio company, estimating the liquidation or collateral value of the portfolio company or its assets, considering offers from third parties to buy the portfolio company, its historical and projected financial results, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied to the prices of comparable companies for factors such as size, marketability, credit risk and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations. For a sample of its Level 3 investments, Generation reviewed independent valuations and reviewed the assumptions in the detailed pricing models used by the fund managers.

As of December 31, 2013, Generation has outstanding commitments to invest in middle market lending, corporate debt securities, and private equity investments of approximately $448 million. These commitments will be funded by Generation s existing nuclear decommissioning trust funds.

12. Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are exposed to certain risks related to ongoing business operations. The primary risks managed by using derivative instruments are commodity price risk and interest rate risk.

Combined Notes to Consolidated Financial Statements (Continued)

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

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

To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, the Registrants are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. The Registrants employ established policies and procedures to manage their risks associated with market fluctuations by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge, and fair value hedge. For commodity transactions, effective with the date of merger with Constellation, Generation no longer utilizes the special election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation s designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivative economic hedges for commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Non-derivative contracts for access to additional generation and certain sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 22 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.

Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. Within Exelon, Generation has the most exposure to commodity price risk. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases, natural gas transportation and pipeline capacity agreements 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

Combined Notes to Consolidated Financial Statements (Continued)

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

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 derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

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 price risk on a ratable basis over three-year periods. As of December 31, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015, and 2016, 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 economic hedges and certain non-derivative contracts, including Generation s sales to ComEd, PECO and BGE to serve their retail load.

In order to fulfill a requirement of the Illinois Settlement Legislation, Generation and ComEd entered into a five-year financial swap contract that expired May 31, 2013. The financial swap was designed to hedge spot market purchases, which, along with ComEd s remaining energy procurement contracts, met its load service requirements. The terms of the financial swap contract required Generation to pay the around-the-clock market price for a portion of ComEd s electricity supply requirement, while ComEd paid a fixed price.

As the contract expired May 31, 2013, all realized impacts have been included in Generation s and ComEd s results of operations. In Exelon s consolidated financial statements, all financial statement effects of the financial swap recorded by Generation and ComEd are eliminated.

In addition, the physical 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 are further discussed in Note 3 Regulatory Matters, qualify and are accounted for under the NPNS 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.

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 began in June 2012. Pursuant to the ICC s Order on December 19, 2012, ComEd s commitments under the existing long-term contracts for energy and associated RECs were reduced in the first quarter of 2013. 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. See Note 3 Regulatory Matters for additional information.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3 Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting

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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 has certain full requirements contracts and block contracts, that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

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 NPNS 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 2013 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 2013 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 is designed to cover about 30% 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.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE s wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for commercial and industrial rate classes. BGE s price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE s actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE s actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. All of BGE s natural gas supply and asset management agreements qualify for the NPNS scope exception and result in physical delivery.

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon s RMC. The proprietary trading activities, which included settled physical sales volumes of 8,762 GWh, 12,958 GWh and 5,742 Gwh for the years ended December 31, 2013, 2012 and 2011, are a complement to

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

Generation s energy marketing portfolio but represent a small portion of Generation s revenue from energy marketing activities. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes.

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2013, Exelon had $1,425 million of notional amounts of fixed-to-floating hedges outstanding and $190 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximate $5 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2013. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. Below is a summary of the interest rate and foreign currency hedges as of December 31, 2013.

	Generation					Other	Exelon
Description	**Derivatives Designated as Hedging Instruments**	**Economic Hedges**	**Proprietary Trading (a)**	**Collateral and Netting (b)**	**Subtotal**	**Derivatives Designated as Hedging Instruments**	**Total**
Mark-to-market derivative assets (Current Assets)	$	$ 3	$ 15	$ (19)	$ (1)	$	$ (1)
Mark-to-market derivative assets (Noncurrent Assets)	26	3	15	(13)	31	7	38
Total mark-to-market derivative assets	$ 26	$ 6	$ 30	$ (32)	$ 30	$ 7	$ 37
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$ (18)	$ 19	$ (1)	$	$ (1)
Mark-to-market derivative liabilities (Noncurrent Liabilities)	(10)	(1)	(13)	13	(11)	(4)	(15)
Total mark-to-market derivative liabilities	$ (11)	$ (2)	$ (31)	$ 32	$ (12)	$ (4)	$ (16)
Total mark-to-market derivative net assets (liabilities)	$ 15	$ 4	$ (1)	$	$ 18	$ 3	$ 21

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

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

The following table provides a summary of the interest rate hedge balances recorded by the Registrants as of December 31, 2012:

	Generation					Other	Exelon
Description	**Derivatives Designated as Hedging Instruments**	**Economic Hedges**	**Proprietary Trading (a)**	**Collateral and Netting (b)**	**Subtotal**	**Derivatives Designated as Hedging Instruments**	**Total**
Mark-to-market derivative assets (Current Assets)	$	$ 3	$ 20	$ (19)	$ 4	$	$ 4
Mark-to-market derivative assets (Noncurrent Assets)	38	8	32	(32)	46	13	59
Total mark-to-market derivative assets	$ 38	$ 11	$ 52	$ (51)	$ 50	$ 13	$ 63
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$ (19)	$ 19	$ (2)	$	$ (2)
Mark-to-market derivative liabilities (Noncurrent Liabilities)	(31)		(32)	32	(31)		(31)
Total mark-to-market derivative liabilities	(32)	(1)	(51)	51	(33)		(33)
Total mark-to-market derivative net assets (liabilities)	$ 6	$ 10	$ 1	$	$ 17	$ 13	$ 30

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

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:

		Twelve Months Ended December 31,					
		2013	**2012**	**2011**	**2013**	**2012**	**2011**
	Income Statement Location	**Gain (Loss) on Swaps**			**Gain (Loss) on Borrowings**		
Generation	Interest expense (a)	$ (15)	$ (6)	$	$	$ (6)	$
Exelon	Interest expense	$ (24)	$ (9)	$ 1	$ 11	$ (3)	$ (1)

(a) For the years ended December 31, 2013 and 2012, the loss on Generation swaps included $16 million and $12 realized in earnings, respectively, with $2 million and an immaterial amount excluded from hedge effectiveness testing, respectively.

During the third and fourth quarters of 2013, Exelon entered into $625 million of notional amounts of fixed-to-floating fair value hedges related to interest rate swaps, which expire in 2020. At December 31, 2013, Exelon and Generation had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,275 million and $550 million, with unrealized gains of $26 million and $23 million, respectively. At December 31, 2012, Exelon and Generation had outstanding fixed-to-floating fair value hedges related to interest rate swaps of $650 million and $550 million that expire in 2015, with unrealized gains of $49 million and $38 million, respectively. During the years ended December 31, 2013 and 2012, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $2 million gain and immaterial, respectively.

Combined Notes to Consolidated Financial Statements (Continued)

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

Cash Flow Hedges. In anticipation of the Continental Wind, LLC non-recourse project financing that was completed on September 30, 2013, Exelon entered into forward-starting interest rate swaps that were designated as cash flow hedges to hedge the change in benchmark interest rates. Upon settlement of the swaps, a $26 million effective gain in OCI was deferred and will be amortized into interest expense over the life of the debt. See Note 13 Debt and Credit Agreements for additional information on the project financing.

In connection with the DOE guaranteed loan for the Antelope Valley acquisition, as discussed in Note 13 Debt and Credit Agreements, Generation entered into a floating-to-fixed forward starting interest rate swap with a notional amount of $485 million and a mandatory early termination date of April 5, 2014. The swap hedges approximately 75% of Generation s future interest rate exposure associated with the financing and was designated as a cash flow hedge. As such, the effective portion of the hedge is recorded in other comprehensive income within Generation s Consolidated Balance Sheets, with any ineffectiveness recorded in Generation s Consolidated Statements of Operations and Comprehensive Income. Net gains (or losses) from settlement of the hedges, to the extent effective, are amortized as an adjustment to the interest expense over the term of the DOE guaranteed loan.

Every time Generation draws down on the loan, an offsetting hedge (fixed-to-floating) is executed and a portion of the cash flow hedge with a notional amount equal to the offsetting hedge, is de-designated and the related gains or losses going forward are reflected in earnings, which are largely offset by the losses or gains in the offsetting hedge.

Antelope Valley received its first loan advance on April 5, 2012, and a series of additional advances subsequently. Generation has entered into a series of fixed-to-floating interest rate swaps with an aggregated notional amount of $350 million, approximately 75% of the loan advance amount to offset portions of the original interest rate hedge, which are not designated as cash flow hedges. The remaining cash flow hedge has a notional amount of $135 million. At December 31, 2013, Generation s mark-to-market non-current derivative liability relating to the interest rate swaps in connection with the loan agreement to fund Antelope Valley was $10 million.

During the third quarter of 2011, a subsidiary of Constellation entered into floating-to-fixed interest rate swaps to manage a portion of the interest rate exposure for anticipated long-term borrowings to finance Sacramento PV Energy. The swaps have a total notional amount of $28 million as of December 31, 2013 and expire in 2027. After the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At December 31, 2013, the subsidiary had a $1 million derivative liability related to these swaps.

During the third quarter of 2012, a subsidiary of Exelon Generation entered into a floating-to-fixed interest rate swap to manage a portion of the interest rate exposure of anticipated long-term borrowings to finance Constellation Solar Horizons. The swap has a notional amount of $27 million as of December 31, 2013, and expires in 2030. This swap is designated as a cash flow hedge. At December 31, 2013, the subsidiary had a $2 million derivative asset related to the swap.

During the years ended December 31, 2013, and 2012, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial.

Economic Hedges. At December 31, 2013, Generation had $144 million in notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate

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component of commodity positions and $195 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

At December 31, 2013, Exelon and Generation had $150 million in notional amounts of fixed-to-floating interest rate swaps that are marked-to-market, with unrealized gains of $2 million. These swaps, which were acquired as part of the merger with Constellation, expire in 2014. During the year ended December 31, 2013, and the period from March 12 to December 31, 2012, the impact on the results of operations was immaterial.

Fair Value Measurement and Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon, Generation, ComEd, PECO and BGE)

Fair value accounting guidance and disclosures about offsetting assets and liabilities 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 legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place either as the contracts deliver, when collateral is requested or in the event of default. Generation s use of cash collateral is generally unrestricted unless Generation is downgraded below investment grade (i.e. to BB+ or Ba1). In the table below, Generation s energy-related economic hedges and proprietary trading derivatives are shown gross and the impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, is aggregated in the collateral and netting column. As of December 31, 2013 and 2012, $10 million of cash collateral posted and $3 million of cash collateral received, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives or as of the balance sheet date there were no positions to offset. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd s use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade (i.e. to BB+ or Ba1).

Cash collateral held by PECO and BGE must be deposited in a non affiliate major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

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

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2013:

Derivatives	Generation Economic Hedges	Generation Proprietary Trading	Generation Collateral and Netting [(a)]	Generation Subtotal [(b)]	ComEd Economic Hedges [(c)]	Exelon Total Derivatives
Mark-to-market derivative assets (current assets)	$ 2,616	$ 1,476	$ (3,364)	$ 728	$	$ 728
Mark-to-market derivative assets (noncurrent assets)	1,344	285	(1,060)	569		569
Total mark-to-market derivative assets	$ 3,960	$ 1,761	$ (4,424)	$ 1,297	$	$ 1,297
Mark-to-market derivative liabilities (current liabilities)	$ (2,023)	$ (1,410)	$ 3,292	$ (141)	$ (17)	$ (158)
Mark-to-market derivative liabilities (noncurrent liabilities)	(804)	(293)	988	(109)	(176)	(285)
Total mark-to-market derivative liabilities	$ (2,827)	$ (1,703)	$ 4,280	$ (250)	$ (193)	$ (443)
Total mark-to-market derivative net assets (liabilities)	$ 1,133	$ 58	$ (144)	$ 1,047	$ (193)	$ 854

(a) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $84 million and $72 million, respectively, and current and noncurrent liabilities are shown net of collateral of $(12) million and $0 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $144 million at December 31, 2013.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2012:

	Generation				ComEd		Exelon
Derivatives	**Economic Hedges** (a)	**Proprietary Trading**	**Collateral and Netting** (b)	**Subtotal** (c)	**Economic Hedges** (a)(d)	**Intercompany Eliminations** (a)	**Total Derivatives**
Mark-to-market derivative assets (current assets)	$ 2,883	$ 2,469	$ (4,418)	$ 934	$	$	$ 934
Mark-to-market derivative assets with affiliate (current assets)	226			226		(226)	
Mark-to-market derivative assets (noncurrent assets)	1,792	724	(1,638)	878			878
Total mark-to-market derivative assets	$ 4,901	$ 3,193	$ (6,056)	$ 2,038	$	$ (226)	$ 1,812
Mark-to-market derivative liabilities (current liabilities)	$ (2,419)	$ (2,432)	$ 4,519	$ (332)	$ (18)	$	$ (350)
Mark-to-market derivative liability with affiliate (current liabilities)					(226)	226	
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,080)	(689)	1,568	(201)	(49)		(250)
Total mark-to-market derivative liabilities	$ (3,499)	$ (3,121)	$ 6,087	$ (533)	$ (293)	$ 226	$ (600)
Total mark-to-market derivative net assets (liabilities)	$ 1,402	$ 72	$ 31	$ 1,505	$ (293)	$	$ 1,212

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $226 million related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above. For Generation, excludes $28 million of noncurrent liability relating to an interest rate swap in connection with a loan agreement to fund Antelope Valley as discussed above.

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, and letters of credit. These are not reflected in the table above.

(c) Current and noncurrent assets are shown net of collateral of $113 million and $201 million, respectively, and current and noncurrent liabilities are shown net of collateral of $ (214) million and $ (131) million, respectively. The total cash collateral received, net of cash collateral posted and offset against mark-to-market assets and liabilities was $ (31) million at December 31, 2012.

(d) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Cash Flow Hedges (Exelon, Generation and ComEd). As discussed previously, effective prior to the merger with Constellation, Generation de-designated all of its cash flow hedges relating to commodity price risk. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and is reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. Generation began recording prospective

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changes in the fair value of these instruments through current earnings from the date of de-designation. Approximately $195 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. Generation expects the settlement of the majority of its cash flow hedges will occur during 2013 through 2014.

Exelon discontinues hedge accounting 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 year ended 2012, the amount reclassified into earnings as a result of the discontinuance of cash flow hedges was immaterial.

The tables below provide the activity of accumulated OCI related to cash flow hedges for the years ended December 31, 2013 and 2012, 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	
	Income Statement Location	Generation Energy-Related Hedges	Exelon Total Cash Flow Hedges
Accumulated OCI derivative gain at January 1, 2012		$ 925[a][d]	$ 488
Effective portion of changes in fair value		432[b]	330[e]
Reclassifications from accumulated OCI to net income	Operating Revenues	(828)[c]	(453)
Ineffective portion recognized in income	Operating Revenues	3	3
Accumulated OCI derivative gain at December 31, 2012		532[a][d]	368
Effective portion of changes in fair value			29[e]
Reclassifications from accumulated OCI to net income	Operating Revenues	(413)[c]	(277)
Accumulated OCI derivative gain at December 31, 2013		$ 119[d]	$ 120

(a) Includes $133 million and $420 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, 2012 and 2011 .
(b) Includes $88 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 year ended December 31, 2012. As of the merger date, cash flow hedges were discontinued, as such, this amount represents changes in fair value prior to the merger date.
(c) Includes $133 million and $375 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, 2013 and 2012, respectively.
(d) Excludes $5 million of losses and $20 million of losses, net of taxes, related to interest rate swaps and treasury rate locks for the years ended December 31, 2013 and 2012, respectively.
(e) Includes $15 million and $9 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, 2013 and 2012, respectively.

During the years ended December 31, 2013, 2012, and 2011 Generation s former energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $683 million, $1,368 million and $968 million pre-tax gain, respectively. Given that the cash flow hedges had primarily consisted of forward power sales and

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power swaps and did not include power and gas options or sales, the ineffectiveness of Generation s cash flow hedges was primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units. Changes in cash flow hedge ineffectiveness were losses of $5 million and a gain of $10 million for the years ended 2012 and 2011, respectively.

Exelon s former energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $464 million, $747 million and $512 million pre-tax gain for the years ended December 31, 2013, 2012 and 2011, respectively. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices, were losses of $5 million and gains of $10 million for the years ended 2012 and 2011, respectively. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods as all energy-related cash flow hedge positions were de-designated prior to the merger date.

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, physical forward sales and purchases, but for which the fair value or cash flow hedge elections were not made. Additionally, Generation enters into interest rate derivative contracts and foreign exchange currency swaps to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars. For the years ended December 31, 2013, 2012 and 2011, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in operating revenues or purchased power and fuel expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in Net fair value changes related to derivatives in Exelon s and Generation s Consolidated Statements of Cash Flows. In the tables below, Change in fair value represents the change in fair value of the derivative contracts held at the reporting date. The Reclassification to realized at settlement represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

Year Ended December 31, 2013	Operating Revenues	Generation Purchased Power and Fuel	Total	Intercompany Eliminations Operating Revenues (a)	Exelon Total
Change in fair value	$ 285	$ 180	$ 465	$ (6)	$ 459
Reclassification to realized at settlement	(65)	104	39	13	52
Net mark-to-market gains	$ 220	$ 284	$ 504	$ 7	$ 511

Year Ended December 31, 2012	Operating Revenues	Generation Purchased Power and Fuel	Total	Intercompany Eliminations Operating Revenues (a)	Exelon Total
Change in fair value	$ (362)	$ 215	$ (147)	$ (94)	$ (241)
Reclassification to realized at settlement	429	238	667	101	768
Net mark-to-market gains	$ 67	$ 453	$ 520	$ 7	$ 527

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

Year Ended December 31, 2011 (As Reported)	Operating Revenues	Exelon and Generation Purchased Power and Fuel	Total
Change in fair value	$ 87	$ 131	$ 218
Reclassification to realized at settlement	(296)	(219)	(515)
Net mark-to-market (losses) [(b)]	$ (209)	$ (88)	$ (297)

Year Ended December 31, 2011 (Pro Forma)	Operating Revenues	Exelon and Generation Purchased Power and Fuel	Total
Change in fair value	$ 258	$ (40)	$ 218
Reclassification to realized at settlement	(516)	1	(515)
Net mark-to-market (losses) [(b)]	$ (258)	$ (39)	$ (297)

(a) Prior to the merger, the five-year financial swap contract between Generation and ComEd was de-designated. As a result, all prospective changes in fair value are recorded to operating revenues and eliminated in consolidation.

(b) Exelon and Generation have historically presented mark-to-market gains and losses within purchased power expense for all non-trading, energy-related derivatives that were not accounted for as cash flow hedges. In 2011, Exelon and Generation classified the mark-to-market gains and losses for contracts, where the underlying hedged transaction was an expected sale to hedge power, to operating revenues.

Proprietary Trading Activities (Exelon and Generation). For the years ended December 31, 2013, and 2012, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity on derivative instruments entered into for proprietary trading purposes. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income and are included in Net fair value changes related to derivatives in Exelon s and Generation s Consolidated Statements of Cash Flows. In the tables below, Change in fair value represents the change in fair value of the derivative contracts held at the reporting date. The Reclassification to realized at settlement represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Location on Income Statement	For the Years Ended December 31, 2013	2012	2011
Change in fair value	Operating Revenue	$ (21)	$ (12)	$ 23
Reclassification to realized at settlement	Operating Revenue	(18)	108	(26)
Net mark-to-market gains (losses)	Operating Revenue	$ (39)	$ 96	$ (3)

Credit Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation s exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically,

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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 process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, 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, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2013. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, further discussed in ITEM 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $38 million, $38 million and $27 million, respectively.

Rating as of December 31, 2013	**Total Exposure Before Credit Collateral**	**Credit Collateral [(a)]**	**Net Exposure**	**Number of Counterparties Greater than 10% of Net Exposure**	**Net Exposure of Counterparties Greater than 10% of Net Exposure**
Investment grade	$ 1,621	$ 172	$ 1,449	$ 1	$ 491
Non-investment grade	27	9	18		
No external ratings					
Internally rated investment grade	416	1	415	1	226
Internally rated non-investment grade	30	2	28		
Total	$ 2,094	$ 184	$ 1,910	$ 2	$ 717

Net Credit Exposure by Type of Counterparty	**December 31, 2013**
Financial Institutions	$ 256
Investor-owned utilities, marketers, power producers	684
Energy cooperatives and municipalities	907
Other	63
Total	$ 1,910

(a) As of December 31, 2013, credit collateral held from counterparties where Generation had credit exposure included $155 million of cash and $29 million of letters of credit .

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

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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, 2013, ComEd s credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 Regulatory Matters for additional 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. The unsecured credit used by the suppliers represents PECO s net credit exposure. As of December 31, 2013, PECO had no net credit exposure with 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 3 Regulatory Matters for additional 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 collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2013, PECO had credit exposure of $9 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 Regulatory Matters for additional information.

BGE s full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier s performance assurance requirements, allow a supplier, or its guarantor, 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, subject to an unsecured credit cap. 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. The unsecured credit used by the suppliers represents BGE s net credit exposure. The seller s credit exposure is calculated each business day. As of December 31, 2013, BGE had no net credit exposure to suppliers.

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BGE s regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE s recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers demands, which are not covered by the gas cost adjustment clause. At December 31, 2013, BGE had credit exposure of $14 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Collateral and Contingent-Related Features (Exelon, Generation, ComEd, PECO and BGE)

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, fuels, emissions allowances and other energy-related products. Certain of Generation s derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges (i.e. NYMEX, ICE). The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. 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. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

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 the exchanges that are fully collateralized) is detailed in the table below:

	For the Years Ended December 31,	
Credit-Risk Related Contingent Feature	**2013**	**2012**
Gross Fair Value of Derivative Contracts Containing this Feature [(a)]	$ (1,056)	$ (1,849)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements [(b)]	$ 846	$ 1,426
Net Fair Value of Derivative Contracts Containing This Feature [(c)]	$ (210)	$ (423)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent ignoring the effects of master netting agreements.

(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.

(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation had cash collateral posted of $72 million, letters of credit posted of $364 million, cash collateral held of $206 million and letters of credit held of $34 million as of December 31, 2013 for counterparties with derivative positions. Generation had cash collateral posted of $527 million and

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letters of credit posted of $563 million and cash collateral held of $499 million and letters of credit held of $45 million at December 31, 2012 for counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e. BB+ or Ba1), Generation could be required to post additional collateral of $2.0 billion as of December 31, 2013 and December 31, 2012. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation s and Exelon s interest rate swaps contain provisions that, in the event of a merger, if Generation s debt ratings were to materially weaken, 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, 2013, Generation s and Exelon s swaps were in an asset position, with a fair value of $18 million and $21 million, respectively.

See Note 24 Segment Information for additional information regarding the letters of credit supporting the cash collateral.

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, 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 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, 2013, ComEd held neither cash nor letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd s annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, 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, 2013, 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 1 Significant Accounting Policies for additional 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, 2013, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2013, PECO could have been required to post approximately $42 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.

BGE s full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE to post collateral.

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BGE s natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE 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, 2013, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of December 31, 2013, BGE could have been required to post approximately $85 million of collateral to its counterparties.

13. Debt and Credit Agreements (Exelon, Generation, ComEd, PECO and BGE)

Short-Term Borrowings

Exelon, ComEd and BGE 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, PECO and BGE had the following amounts of commercial paper borrowings at December 31, 2013 and 2012:

Commercial Paper Issuer	Maximum Program Size at December 31, 2013 [(a)]	2012 [(a)]	Outstanding Commercial Paper at December 31, 2013	2012	Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31, 2013	2012
Exelon Corporate	$ 500	$ 500	$	$	0.27%	0.47%
Generation	5,600	5,600			0.32%	0.45%
ComEd	1,000	1,000	184		0.40%	0.50%
PECO	600	600			n.a.	n.a.
BGE	600	600	135		0.31%	0.43%
Total	$ 8,300	$ 8,300	$ 319	$		

(a) Equals aggregate bank commitments under the revolving and bilateral credit agreements (with the exception of a $75 million bilateral agreement) that backstop the commercial paper program. 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 outstanding commercial paper does not reduce available capacity under a Registrant s credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit agreement.

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At December 31, 2013, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit agreements:

Borrower	Aggregate Bank Commitment (a)	Facility Draws	Outstanding Letters of Credit	Available Capacity at December 31, 2013 Actual	Available Capacity at December 31, 2013 To Support Additional Commercial Paper (b)
Exelon Corporate	$ 500	$	$ 2	$ 498	$ 498
Generation	5,675		1,413	4,262	4,187
ComEd	1,000			1,000	816
PECO	600		1	599	599
BGE	600			600	465
Total	$ 8,375	$	$ 1,416	$ 6,959	$ 6,565

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd s, PECO s and BGE s service territories. These facilities expire on October 17, 2014 and are solely for issuing letters of credit. As of December 31, 2013, letters of credit issued under these agreements totaled $20 million, $18 million, $21 million and $1 million for Generation, ComEd, PECO and BGE, respectively.

(b) Excludes $75 million bilateral credit facility that does not back Generation s commercial paper program.

For the year ended December 31, 2013, there were no borrowings under the Registrants credit facilities.

The following tables present the short-term borrowings activity for Exelon, Generation, ComEd, and BGE during 2013, 2012 and 2011. PECO did not have any short-term borrowings outstanding during 2013, 2012 or 2011.

Exelon

	2013	2012	2011
Average borrowings	$ 254	$ 199	$ 218
Maximum borrowings outstanding	682	505	600
Average interest rates, computed on a daily basis	0.37%	0.48%	0.50%
Average interest rates, at December 31	0.35%	n.a.	0.44%

Generation

	2013	2012	2011
Average borrowings	$ 42	$ 4	$ 51

Maximum borrowings outstanding	291	165	304
Average interest rates, computed on a daily basis	0.32%	0.45%	0.48
Average interest rates, at December 31	n.a.	n.a.	n.a.

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ComEd

	2013	2012	2011
Average borrowings	$ 203	$ 110	$ 36
Maximum borrowings outstanding	446	366	407
Average interest rates, computed on a daily basis	0.40%	0.50%	0.71%
Average interest rates, at December 31	0.37%	n.a.	n.a.

BGE

	2013	2012	2011
Average borrowings	$ 35	$ 6	$ 26
Maximum borrowings outstanding	135	76	190
Average interest rates, computed on a daily basis	0.31%	0.43%	0.38%
Average interest rates, computed at December 31	0.31%	n.a.	n.a.

Credit Agreements

On January 23, 2013, Generation entered into a two year $75 million bilateral letter of credit facility with a bank. The credit agreement expires in January 2015. This facility will solely be utilized by Generation to issue letters of credit.

On March 14, 2013, ComEd extended its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2018, and ComEd may request another one-year extension of that term. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any such extension or increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

On August 10, 2013, Exelon Corporate, Generation, PECO and BGE amended and extended their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively. The new covenants are substantially consistent with existing covenants. Costs incurred to amend and extend the facilities for Exelon Corporate, Generation, PECO and BGE were not material.

Effective August 10, 2013, Exelon and ComEd entered into amendments to each of their respective revolving credit facilities (the Amendments). The Amendments relate to the IRS s challenge to the position taken by Exelon on its 1999 federal income tax return with respect to the sale of ComEd s fossil generating assets in a like-kind exchange tax position. The Amendments are intended to exclude the non-cash impact of the like-kind exchange tax position from the calculation of the interest coverage ratio under each of Exelon and ComEd s respective credit facilities. See Note 12 Income Taxes for additional information.

On January 27, 2014 ComEd began the process of extending its unsecured syndicated revolving credit facility, with aggregate bank commitments of $1.0 billion. The transaction is expected to close and become effective in March 2014, with a maturity of five years from the close of the transaction. No changes are expected to be made to the facility other than extension of the term for an additional one year period.

Generally, it is expected that costs incurred to extend the facility will be amortized over the newly extended life of the facility.

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Borrowings under Exelon Corporate s, Generation s, ComEd s, PECO s and BGE s credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular registrant s credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 27.5, 0.0 and 7.5 basis points for prime based borrowings and 127.5, 127.5, 127.5, 100.0 and 107.5 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of the borrower.

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.

On October 18, 2013, Generation, ComEd, PECO and BGE refinanced their respective minority and community bank credit facility agreements in the amounts of $50 million, $34 million, $34 million and $5 million, respectively. These facilities, which expire in October 2014, are solely utilized to issue letters of credit.

Each credit facility 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, 2013:

	Exelon	Generation	ComEd	PECO	BGE
Credit facility threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At December 31, 2013, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	7.67	11.45	5.20	8.29	7.85

Accounts Receivable Agreement

PECO was party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its accounts receivable designated under the agreement in exchange for proceeds of $210 million, which was classified as a short-term note payable on Exelon s and PECO s Consolidated Balance Sheets as of December 31, 2012. The agreement terminated on August 30, 2013 and PECO paid down the outstanding principal of $210 million. The financial institution no longer has an undivided interest in the accounts receivable designated under the agreement. As of December 31, 2012, the financial institution s undivided interest in Exelon s and PECO s gross accounts receivable was equivalent to $289 million, which represented the financial institution s interest in PECO s eligible receivables as calculated under the terms of the agreement. The agreement required PECO to maintain eligible receivables at least equivalent to the financial institution s undivided interest.

Combined Notes to Consolidated Financial Statements (Continued)

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

Willis Tower Capital Lease

In the second quarter of 2013, ComEd entered into a 20-year capital lease for distribution substation space at Willis Tower in Chicago, Illinois. Exelon and ComEd recorded $8 million on their Consolidated Balance Sheets within property plant and equipment and long-term debt at the inception of the lease. ComEd will make lease payments of less than $1 million annually in 2013-2017 and approximately $7 million in aggregate thereafter.

Long-Term Debt

The following tables present the outstanding long-term debt at Exelon, Generation, ComEd, PECO and BGE as of December 31, 2013 and 2012:

Exelon

	Rates		Maturity Date	December 31, 2013	December 31, 2012
Long-term debt					
First Mortgage Bonds [(a)(b)] :					
Fixed rates	1.20%	7.63%	2013-2043	$ 7,746	$ 7,397
Unsecured bonds	2.80%	6.35%	2013-2036	1,750	1,850
Rate stabilization bonds	5.68%	5.82%	2016-2017	265	332
Senior unsecured notes	2.00%	7.60%	2014-2042	7,571	8,021
Pollution control notes:					
Fixed rates	4.10%		2014	20	20
Non-recourse debt:					
Fixed rates	2.33%	5.50%	2031-2037	1,077	238
Variable rates	1.96%	2.77%	2013-2053	150	262
Notes payable and other [(c)]	4.50%	7.83%	2014-2053	181	177
Total long-term debt				18,760	18,297
Unamortized debt discount and premium, net				(19)	(17)
Fair value adjustment				384	448
Fair value hedge carrying value adjustment, net				7	17
Long-term debt due within one year				(1,509)	(1,047)
Long-term debt				$ 17,623	$ 17,698
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
Subordinated debentures to BGE Trust		6.20%	2043	258	258

Total long-term debt to financing trusts	$ 648	$ 648

(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.

Combined Notes to Consolidated Financial Statements (Continued)

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

(c) Includes capital lease obligations of $41 million and $30 million at December 31, 2013 and 2012, respectively. Lease payments of $4 million, $4 million, $4 million, $5 million, $5 million and $19 million will be made in 2014, 2015, 2016, 2017, 2018 and thereafter, respectively.

(d) Amounts owed to these financing trusts are recorded as debt to financing trusts within Exelon s Consolidated Balance Sheets.

Generation

	Rates		Maturity Date	December 31, 2013	December 31, 2012
Long-term debt					
Senior unsecured notes	2.00%	7.60	2014-2042	$ 6,271	$ 6,721
Social Security Administration	2.93%		2015	1	
Pollution control notes:					
Fixed rates	4.10%		2014	20	20
Non-recourse debt:					
Fixed rates	2.33%	5.50%	2031-2037	1,077	238
Variable rates	1.96%	2.77%	2014-2030	150	262
Notes payable and other [(a)]	4.50%	7.83%	2014-2022	33	30
Total long-term debt				7,552	7,271
Fair value adjustment				166	199
Unamortized debt discount and premium, net				11	13
Long-term debt due within one year				(561)	(28)
Long-term debt				$ 7,168	$ 7,455

(a) Includes Generation s capital lease obligations of $33 million and $30 million at December 31, 2013 and 2012, respectively. Generation will make lease payments of $4 million, $4 million, $4 million, $5 million, $5 million and $11 million in 2014, 2015, 2016, 2017, 2018 and thereafter, respectively.

During January 2014, Generation redeemed its $20 million 4.10% pollution control revenue bonds due July 1, 2014 and its $500 million 5.35% senior unsecured notes at maturity.

ComEd

	Rates		Maturity Date	December 31, 2013	December 31, 2012
Long-term debt					
First Mortgage Bonds [(a)(b)]:					
Fixed rates	1.63%	7.63%	2013-2043	$ 5,546	$ 5,447
Notes payable and other [(c)]	6.95%	7.49%	2014-2053	148	140
Total long-term debt				5,694	5,587

Unamortized debt discount and premium, net			(19)	(20)
Long-term debt due within one year			(617)	(252)
Long-term debt			$ 5,058	$ 5,315
Long-term debt to financing trust [(d)]				
Subordinated debentures to ComEd Financing III	6.35%	2042	$ 206	$ 206

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Combined Notes to Consolidated Financial Statements (Continued)

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

(a) Substantially all of ComEd s assets other than expressly excepted property are subject to the lien of its mortgage indenture.
(b) Includes First Mortgage Bonds issued under the ComEd mortgage indenture securing pollution control bonds and notes.
(c) Includes ComEd s capital lease obligations of $8 million at December 31, 2013. Lease payments of less than $1 million will be made from 2014 through expiration at 2053.
(d) Amount owed to this financing trust is recorded as debt to financing trust within ComEd s Consolidated Balance Sheets.

On January 10, 2014, ComEd issued $300 million aggregate principal amount of its First Mortgage 2.150% Bonds, Series 115, due January 15, 2019, and $350 million aggregate principal amount of its First Mortgage 4.700% Bonds, Series 116, due January 15, 2044. The proceeds of the Bonds were used by ComEd to refinance the $17 million outstanding principal amount of its First Mortgage 5.850% Bonds, Pollution Control Series 1994C, due January 15, 2014, and the $600 million outstanding principal amount of its First Mortgage 1.625% Bonds, Series 110, due January 15, 2014, and to fund other general corporate purposes in 2014.

PECO

	Rates		Maturity Date	December 31, 2013	December 31, 2012
Long-term debt					
First Mortgage Bonds [a][b]:					
Fixed rates	1.20%	5.95%	2013-2043	$ 2,200	$ 1,950
Total long-term debt				2,200	1,950
Unamortized debt discount and premium, net				(3)	(3)
Long-term debt due within one year				(250)	(300)
Long-term debt				$ 1,947	$ 1,647
Long-term debt to financing trusts [c]					
Subordinated debentures to PECO Trust III		7.38%	2028	$ 81	$ 81
Subordinated debentures to PECO Trust IV		5.75%	2033	103	103
Long-term debt to financing trusts				$ 184	$ 184

(a) Substantially all of PECO s assets are subject to the lien of its mortgage indenture.
(b) Includes First Mortgage Bonds issued under the PECO mortgage indenture securing pollution control bonds and notes.
(c) Amounts owed to this financing trust are recorded as debt to financing trusts within PECO s Consolidated Balance Sheets.

BGE

December 31,

	Rates		Maturity Date	2013	2012
Long-term debt					
Unsecured bonds	2.80%	6.35%	2013-2036	$ 1,750	$ 1,850
Rate stabilization bonds	5.68%	5.82%	2016-2017	265	$ 332
Total long-term debt				2,015	2,182
Unamortized debt discount and premium, net				(4)	(4)
Long-term debt due within one year				(70)	(467)
Long-term debt				$ 1,941	$ 1,711
Long-term debt to financing trusts [(a)]					
Subordinated debentures to BGE Capital Trust II		6.20%	2043	$ 258	$ 258

(a) Amount owed to this financing trust is recorded as debt to financing trust within BGE s Consolidated Balance Sheets.

Combined Notes to Consolidated Financial Statements (Continued)

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

Long-term debt maturities at Exelon, Generation, ComEd, PECO and BGE in the periods 2014 through 2018 and thereafter are as follows:

Year	Exelon	Generation	ComEd	PECO	BGE
2014	$ 1,428	$ 561	$ 617	$ 250	$
2015	1,615	555	260		
2016	1,346	81	665	300	300
2017	1,396	706	425		265
2018	1,345	5	840	500	
Thereafter	12,278[a]	5,644	3,093[b]	1,334[c]	1,708[d]
Total	$ 19,408	$ 7,552	$ 5,900	$ 2,384	$ 2,273

(a) Includes $648 million due to ComEd, PECO and BGE financing trusts.
(b) Includes $206 million due to ComEd financing trust.
(c) Includes $184 million due to PECO financing trusts.
(d) Includes $258 million due to BGE financing trust.

Non-Recourse Debt

The following are descriptions of activity with respect to certain indebtedness of Exelon s project subsidiaries that is outstanding as of December 31, 2013. The indebtedness described below is specific to certain generating facilities pledged as collateral with a net book value of approximately $1.9 billion at December 31, 2013, and all associated project financing liabilities are non-recourse to Exelon and Generation.

Continental Wind. On September 30, 2013, Continental Wind, LLC (Continental Wind), an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $613 million aggregate principal amount of Continental Wind s 6.00% senior secured notes due February 28, 2033. Continental Wind owns and operates a portfolio of wind farms in Idaho, Kansas, Michigan, Oregon, New Mexico and Texas with a total net capacity of 667 MW. The net proceeds were distributed to Generation for its general business purposes. In connection with this non-recourse project financing, Exelon terminated existing interest rate swaps with a total notional amount of $350 million during the third quarter of 2013, and realized a total gain of $26 million upon termination. The gain on the interest rate swaps was recorded within OCI and will reduce the effective interest rate over the life of the debt for Exelon. See Note 12 Derivative Financial Instruments for additional information on the interest rate swaps.

In addition, Continental Wind entered into a $131 million letter of credit facility and $10 million working capital revolver facility. Continental Wind has issued letters of credit to satisfy certain of its credit support and security obligations. As of December 31, 2013, the Continental Wind letter of credit facility had $93 million in letters of credit outstanding related to the project.

ExGen Renewables Energy I LLC. On February 6, 2014, ExGen Renewables I, LLC (EGR), an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $300 million aggregate principal amount of EGR s LIBOR plus 425 bps non-recourse senior secured loan, due February 6, 2021. EGR indirectly owns Continental Wind LLC (Continental).

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

Combined Notes to Consolidated Financial Statements (Continued)

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

completed in the first half of 2014. The loan will mature on January 5, 2037. Interest rates on the loan are fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity.

In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2013, Generation had $334 million in letters of credit outstanding related to the project The letters of credit balance is expected to decline over time as scheduled equity contributions for the project are made.

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. As Generation received additional loan advances, it subsequently entered into a series of fixed-to-floating interest rate swaps to offset portions of the original interest rate hedge. See Note 12 Derivative Financial Instruments for additional information regarding interest rate swaps associated with Antelope Valley.

Sacramento PV Energy. In July, 2011, a subsidiary of Generation entered into a $41 million non-recourse project financing for a 30MW solar facility in Sacramento, California. As of December 31, 2013, $37 million was outstanding. Borrowings under the facility bear interest at a variable rate, payable quarterly, and are secured by equity interests and assets of the subsidiary. As of December 31, 2013, the subsidiary had interest rate swaps with a notional value of $29 million in order to convert the variable interest payments to fixed payments on 75% of the $41 million facility. See Note 12 Derivative Financial Instruments for additional information regarding interest rate swaps.

Constellation Solar Horizons Financing. In September 2012, a subsidiary of Generation entered into an 18-year $38 million non-recourse variable interest note to recover capital used to build a 16 MW solar facility in Emmitsburg, Maryland. Interest is payable quarterly, and the note is secured by the equity interests and assets of the subsidiary. As of December 31, 2013, $36 million was outstanding. The subsidiary also executed interest rate swaps for a notional amount of $29 million in order to convert the variable interest payments to fixed payments on 75% of the $38 million facility amount. See Note 12 Derivative Financial Instruments for additional information regarding interest rate swaps.

Secured Solar Credit Lending Agreement. In December 2013, a Generation subsidiary, Constellation Solar, LLC, paid off the remaining balance of the three-year senior secured credit facility that is designed to support the growth of solar operations in the amount of $94 million and terminated the facility. The facility was scheduled to mature in June of 2014.

Other Solar Project Financings. Generation has the following amounts outstanding under solar project loan agreements:

- $7 million fully amortizing by June 30, 2031 related to a solar project at the Denver International Airport, and
- $10 million fully amortizing by December 31, 2031 related to a solar project in Holyoke, Massachusetts.

Upstream Gas Property Asset-Based Lending Agreement

Generation has a five year asset-based lending agreement associated with certain upstream gas properties that it owns. The borrowing base committed under the facility is $110 million and can increase to a total of $500 million if the assets support a higher borrowing base and Generation is able

Combined Notes to Consolidated Financial Statements (Continued)

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

to obtain additional commitments from lenders. The facility was amended and extended through January 2019. Borrowings under this facility are secured by the upstream gas properties, and the lenders do not have recourse against Exelon or Generation in the event of a default. As of December 31, 2013, $77 million was outstanding under the facility with interest payable quarterly. The facility includes a provision that requires the Generation entities owning the upstream gas properties subject to the agreement to maintain a current ratio of one-to-one. As of December 31, 2013, Generation was in compliance with this provision.

14. Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

Income tax expense (benefit) from continuing operations is comprised of the following components:

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 744	$ 250	$ 160	$ 126	$ 9
Deferred	140	360	(27)	23	100
Investment tax credit amortization	(15)	(11)	(2)	(1)	(1)
State					
Current	181	50	50	16	
Deferred	(6)	(34)	(29)	(2)	26
Total	$ 1,044	$ 615	$ 152	$ 162	$ 134

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 37	$ 104	$ (40)	$ 88	$ (97)
Deferred	701	326	237	25	101
Investment tax credit amortization	(11)	(6)	(2)	(2)	(1)
State					
Current	(25)	(12)	6	4	
Deferred	(75)	88	38	12	4
Total	$ 627	$ 500	$ 239	$ 127	$ 7

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 1	$ 431	$ (329)	$ (71)	$ (71)
Deferred	1,200	435	544	223	130
Investment tax credit amortization	(12)	(7)	(3)	(2)	(1)
State					
Current	(3)	74	(123)	(37)	
Deferred	271	123	161	33	17

Total	$ 1,457	$ 1,056	$ 250	$ 146	$ 75

Combined Notes to Consolidated Financial Statements (Continued)

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

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	4.7	1.6	3.4	1.6	4.9
Qualified nuclear decommissioning trust fund income	3.7	6.1			
Tax exempt income	(0.2)	(0.3)			
Health care reform legislation	0.1		0.7		0.2
Amortization of investment tax credit, net deferred taxes	(1.9)	(3.0)	(0.6)	(0.1)	
Production tax credits and other credits	(2.1)	(3.4)	(0.1)		
Plant basis differences	(1.6)		(0.8)	(7.1)	(0.2)
Other	(0.1)	0.7	0.3	(0.3)	(0.9)
Effective income tax rate	37.6%	36.7%	37.9%	29.1%	39.0%

For the Year Ended December 31, 2012	Exelon [(a)]	Generation [(a)]	ComEd	PECO	BGE [(b)]
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	(3.6)	4.7	4.6	2.0	24.3
Qualified nuclear decommissioning trust fund income	5.4	9.1			
Tax exempt income	(0.2)	(0.4)			
Health care reform legislation	0.1		0.4		11.6
Amortization of investment tax credit, net deferred taxes	(1.1)	(1.3)	(0.4)	(0.3)	(8.6)
Production tax credits and other credits	(2.2)	(3.7)			
Plant basis differences	(2.4)		(0.3)	(11.5)	(9.0)
Merger expenses [(c)]	2.4				24.2
Fines and Penalties	2.6	4.4			
Other	(1.1)	(0.5)	(0.6)	(0.2)	(13.9)
Effective income tax rate	34.9%	47.3%	38.7%	25.0%	63.6%

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE [(b)]
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	4.4	4.5	3.6	(0.5)	5.2
Qualified nuclear decommissioning trust fund income	0.5	0.7			
Domestic production activities deduction	(0.3)	(0.4)			
Tax exempt income	(0.2)	(0.2)			
Health care reform legislation	(0.2)		(1.0)		(0.5)
Amortization of investment tax credit	(0.3)	(0.3)	(0.4)	(0.3)	(0.5)
Production tax credits	(0.9)	(1.2)			
Plant basis differences	(1.0)		(0.3)	(6.9)	(2.0)
Other	(0.2)	(0.7)	0.6		(1.7)
Effective income tax rate	36.8%	37.4%	37.5%	27.3%	35.5%

Combined Notes to Consolidated Financial Statements (Continued)

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

(a) Exelon activity for the twelve months ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012 December 31, 2012. Generation activity for the twelve months ended December 31, 2012 includes the results of Constellation for March 12, 2012 December 31, 2012.
(b) BGE activity represents the activity for the twelve months ended December 31, 2012 and 2011.
(c) Prior to the close of the merger, the Registrants recorded the applicable taxes on merger transaction costs assuming the merger would not be completed. Upon closing of the merger, the Registrants reversed such taxes for those merger transaction costs that were determined to be non tax-deductible upon successful completion of a merger.

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2013 and 2012 are presented below:

For the Year Ended December 31, 2013	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Plant basis differences	$ (11,612)	$ (3,879)	$ (3,523)	$ (2,573)	$ (1,538)
Accrual based contracts	(214)	(214)			
Derivatives and other financial instruments	(509)	(505)	(4)		
Deferred pension and post-retirement obligation	1,489	(362)	(522)		(74)
Nuclear decommissioning activities	(647)	(646)			
Deferred debt refinancing costs	173	79	(21)	(3)	(5)
Regulatory	(1,611)		(241)	42	(253)
Tax loss carryforward	252	76	47	11	52
Tax credit carryforward	534	534			
Investment in CENG	(541)	(541)			
Other, net	804	67	154	122	26
Deferred income tax liabilities (net)	$ (11,882)	$ (5,391)	$ (4,110)	$ (2,401)	$ (1,792)
Unamortized investment tax credits	(490)	(454)	(22)	(3)	(6)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$ (12,372)	$ (5,845)	$ (4,132)	$ (2,404)	$ (1,798)

For the Year Ended December 31, 2012	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Plant basis differences	$ (10,689)	$ (3,545)	$ (3,537)	$ (2,437)	$ (1,553)
Accrual based contracts	(389)	(389)			
Derivatives and other financial instruments	(392)	(479)	(4)		
Deferred pension and post-retirement obligation	2,356	(439)	(598)	(11)	(12)
Nuclear decommissioning activities	(604)	(604)			
Deferred debt refinancing costs	(537)	163	(25)	(4)	(4)
Regulatory	(1,857)		(116)	50	(253)
Tax loss carryforward	421	226	32	14	105
Tax credit carryforward	226	226			
Investment in CENG	(405)	(419)			
Other, net	701	9	83	100	67
Deferred income tax liabilities (net)	$ (11,169)	$ (5,251)	$ (4,165)	$ (2,288)	$ (1,650)
Unamortized investment tax credits	(251)	(216)	(24)	(3)	(6)
	$ (11,420)	$ (5,467)	$ (4,189)	$ (2,291)	$ (1,656)

Total deferred income tax liabilities (net) and unamortized investment tax credits

Combined Notes to Consolidated Financial Statements (Continued)

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

The following table provides the Registrants carryforwards and any corresponding valuation allowances as of December 31, 2013.

	Exelon	Generation	ComEd	PECO	BGE
Federal					
Federal net operating loss	$ 377[(a)]	$ 36	$ 139	$	$ 31
Deferred taxes on Federal net operating loss	132	13	49		11
Federal general business credits carryforward	556[(b)]	556			
State					
State net operating losses and other credit carryforwards	3,061[(c)]	1,498[(d)]		167[(e)]	768[(f)]
Deferred taxes on state tax attributes (net)	161	82		11	41
Valuation allowance on state tax attributes	13	11			1

(a) Exelon s federal net operating loss will expire beginning in 2031
(b) Exelon s federal general business credit carryforwards will expire beginning in 2032
(c) Exelon s state net operating losses and other carryforwards, which are presented on a post-apportioned basis, will expire beginning in 2014
(d) Generation s state net operating losses and other carryforwards, which are presented on a post-apportioned basis, will expire beginning in 2014
(e) PECO s state net operating losses will expire beginning in 2031
(f) BGE s state net operating losses will expire beginning in 2026

Tabular reconciliation of unrecognized tax benefits

The following table provides a reconciliation of the Registrants unrecognized tax benefits as of December 31, 2013, 2012 and 2011:

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2013	$ 1,024	$ 876	$ 67	$ 44	$
Increases based on tax positions related to 2013	19	19			
Change to positions that only affect timing	649	36	257		
Increases based on tax positions prior to 2013	493	493			
Decreases based on tax positions prior to 2013	(6)	(5)			
Decreases from expiration of statute of limitations	(4)	(4)			
Unrecognized tax benefits at December 31, 2013	$ 2,175	$ 1,415	$ 324	$ 44	$

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2012	$ 807	$ 683	$ 70	$ 48	$ 11
Merger Balance Transfer	195	183			
Increases based on tax positions related to 2012	34	3			
Change to positions that only affect timing	(88)	(69)	(3)	(4)	(11)
Increases based on tax positions prior to 2012	91	91			
Decreases based on tax positions prior to 2012	(6)	(6)			
Decreases related to settlements with taxing authorities	(2)	(2)			
Decreases from expiration of statute of limitations	(7)	(7)			

Unrecognized tax benefits at December 31, 2012	$ 1,024	$	876	$	67	$	44	$

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Combined Notes to Consolidated Financial Statements (Continued)

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

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2011	$ 787	$ 664	$ 72	$ 44	$ 73
Increases based on tax positions related to 2011	5	1		4	
Change to positions that only affect timing	21	24	(2)		(62)
Decreases based on tax positions prior to 2011	(3)	(3)			
Decrease from expiration of statute of limitations	(3)	(3)			
Unrecognized tax benefits at December 31, 2011	$ 807	$ 683	$ 70	$ 48	$ 11

Included in Exelon s unrecognized tax benefits balance at December 31, 2013 and 2012 are approximately $1,387 million and $730 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 $788 million and $768 million, respectively, of unrecognized tax benefits at December 31, 2013 that, if recognized, would decrease the effective tax rate. Exelon and Generation had $294 million and $263 million, respectively, of unrecognized tax benefits at December 31, 2012 that, if recognized, would decrease the effective tax rate.

Reasonably possible that total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Nuclear Decommissioning Liabilities (Exelon and Generation)

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. Generation filed a complaint in the United States Court of Federal Claims on February 20, 2009 to contest this determination. During the first and second quarters of 2013, AmerGen and the DOJ completed and filed cross motions for summary judgment. On September 17, 2013, the Court granted the government s motion denying AmerGen s claims for refund. Exelon is expecting to appeal this decision to the United States Court of Appeals for the Federal Circuit during 2014.

Due to the possibility of final resolution through an appellate decision, Generation continues to believe that it is reasonably possible that the total amount of unrecognized tax benefits will significantly decrease in the next twelve months.

Settlement of Income Tax Audits and Litigation

As of December 31, 2013, Exelon and Generation had approximately $256 million of other federal and state unrecognized tax benefits that could significantly increase or decrease within the 12 months

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

after the reporting date as a result of completing federal and state audits and expected statute of limitation expirations that if recognized would decrease the effective tax rate. In January 2014, certain of these unrecognized tax benefits were effectively settled and thus will result in reduced tax expense of $33 million at Generation in the first quarter of 2014.

See Other Tax Matters Like Kind Exchange section below for information regarding the amount of unrecognized tax benefits associated with this matter that could change significantly within the next 12 months.

Total amounts of interest and penalties recognized

The following table represents the net interest receivable (payable), including interest related to uncertain tax positions reflected in the Registrants Consolidated Balance Sheets. Prior to the merger legacy Constellation recorded interest related to uncertain tax positions as a tax and not interest.

Net interest receivable (payable) as of	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
December 31, 2013	$ (349)	$ (37)	$ (174)	$ 3	$
December 31, 2012	31	(20)	107	2	

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. The Registrants have not accrued any penalties with respect to uncertain tax positions. Prior to the merger legacy Constellation recorded interest related to uncertain tax positions as a tax and not interest.

Net interest expense (income) for the years ended	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
December 31, 2013	$ 391	$ 17	$ 281	$ (1)	$
December 31, 2012	(1)	11	(20)	(1)	9
December 31, 2011	(56)	(40)	(14)	(1)	(3)

Description of tax years that remain open to assessment by major jurisdiction

Taxpayer	**Open Years**
Exelon (and predecessors) and subsidiaries consolidated Federal income tax returns	1999-2012
Constellation and subsidiaries consolidated Federal income tax returns	2009-March 2012
Exelon and subsidiaries Illinois unitary income tax returns	2007-2012
Constellation combined New York corporate income tax returns	2008-2012
Various separate company Pennsylvania corporate net income tax returns	2008-2012
BGE Maryland Corporate net income tax returns	2004-2007, 2009-2012
Various other (Non-BGE) Maryland Corporate net income tax returns	2009-2012

Other Tax Matters

Like-Kind Exchange

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately $2.8 billion of tax gain on the sale of ComEd s fossil generating assets. 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

Combined Notes to Consolidated Financial Statements (Continued)

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

Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. The IRS disagreed with this position and asserted that the entire gain of approximately $2.8 billion was taxable in 1999.

Exelon has been unable to reach agreement with the IRS regarding the dispute over the like kind exchange position. The IRS has 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. The IRS has also asserted a penalty of approximately $87 million for a substantial understatement of tax.

Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Although Exelon has been and remains willing to settle the disagreement on terms commensurate with the hazards of litigation, Exelon does not believe a settlement is possible. Because Exelon believed, as of December 31, 2012, that it was more-likely-than-not that Exelon would prevail in litigation, Exelon and ComEd had no liability for unrecognized tax benefits with respect to the like-kind exchange position.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit reversed the U.S. Court of Federal Claims and reached a decision for the government in Consolidated Edison v. United States. The Court disallowed Consolidated Edison s deductions stemming from its participation in a LILO transaction that the IRS also has characterized as a tax shelter.

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon s current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it is no longer more-likely-than-not that its position will be sustained. As a result, in the first quarter of 2013, Exelon recorded a non-cash charge to earnings of approximately $265 million, which represents the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013 that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $170 million was recorded at ComEd. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd s equity. As such, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a $172 million receivable and non-cash equity contributions from Exelon. Exelon and ComEd will continue to accrue interest on the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. In addition ComEd will continue to record non-cash equity contributions from Exelon in the amount of the net after-tax interest charges attributable to ComEd in connection with the like-kind exchange position. Exelon continues to believe that it is unlikely that the $87 million penalty assertion will ultimately be sustained and therefore no liability for the penalty has been recorded.

On September 30, 2013, the Internal Revenue Service issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue. The litigation could take three to five years including appeals, if necessary. Decisions in the Tax Court are not controlled by the Federal Circuit s decision in Consolidated Edison.

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

As of December 31, 2013, in the event of a fully successful IRS challenge to Exelon s like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $840 million, of which approximately $305 million would be attributable to ComEd after consideration of Exelon s agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash impacts would likely change by a material amount.

Accounting for Generation Repairs (Exelon and Generation)

On April 30, 2013, the IRS issued Revenue Procedure 2013-24 providing guidance for determining the appropriate tax treatment of costs incurred to repair electric generation assets. Generation expects to change its method of accounting for deducting repairs in accordance with this guidance beginning with its 2014 tax year. Generation has estimated that adoption of the new method will result in a cash tax detriment of approximately $100 - $120 million.

Accounting for Electric Transmission and Distribution Property Repairs (Exelon, Generation, ComEd, PECO and BGE)

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 and PECO adopted the safe harbor in the Revenue Procedure for the 2011 and 2010 tax years, respectively. 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 domestic production activities 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 resulted in a cash tax benefit at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million, $95 million respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million related to a decreased domestic production activities deduction.

BGE adopted the safe harbor for the short period 2012 pre-merger tax year. For the year ended December 31, 2012, the adoption of the safe harbor resulted in a cash tax benefit at BGE in the amount of $27 million.

See Note 3 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.

Accounting for Gas Distribution Property Repairs (Exelon, PECO and BGE).

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The change to the newly adopted method for the 2011 tax year and 2012 resulted in a tax benefit of $26 million at Exelon, of which $29 million in tax benefit is recorded at PECO, partially offset by an expense recorded at Generation to reflect a reduction in its domestic production activities deduction. BGE changed its method of accounting for gas distribution repairs for the 2008 tax year. The IRS is expected to issue industry guidance in the near future. Exelon, PECO and BGE will then determine the financial statement impacts of the gas distribution repair costs accounting method changes after guidance is issued.

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

Accounting for Final Tangible Property Regulations (Exelon, Generation, ComEd, PECO, and BGE)

On September 19, 2013, the Treasury Department and the IRS published final regulations regarding the tax treatment of costs incurred to acquire, produce, or improve tangible property. The Registrants have assessed the financial impact of this guidance and do not expect it to have a material impact. Any changes in method of accounting required to conform to the final regulations will be made for the Registrant s 2014 taxable year.

2011 Illinois State Tax Rate Legislation (Exelon, Generation and ComEd)

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 re-evaluated 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)

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. 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, resulting in recording 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.

As a result of the merger with Constellation, Exelon and Generation re-evaluated their long-term state tax apportionment in the first quarter of 2012. The total effect of revising the long-term state tax apportionment resulted in the recording of a deferred state tax asset of $72 million (net of Federal taxes) for Exelon. Of this, a benefit in the amount of $116 million and $14 million (net of Federal taxes) was recorded for Exelon and Generation, respectively, for the three months ended March 31, 2012. Further, Exelon and Generation recorded deferred state tax liabilities of $44 million and $14 million (net of Federal taxes), respectively, as part of purchase accounting during the three months ended March 31, 2012. The long-term state tax apportionment also was updated in the fourth quarter of 2012, resulting in the recording of a deferred state tax benefit of

$3 million (net of Federal taxes) for Exelon, and a deferred state tax expense of $7 million (net of Federal taxes) for Generation. There was no change to the long-term state tax apportionment for BGE, ComEd and PECO.

The long-term state tax apportionment was revised in the fourth quarter of 2013 pursuant to its long-term state tax apportionment policy, resulting in the recording of amounts that are immaterial for Exelon and Generation, respectively.

Allocation of Tax Benefits (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE 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 2013, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $26 million and $27 million, respectively. During 2013, ComEd and BGE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of ComEd s and BGE s 2013 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010. During 2012, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $48 million and $9 million, respectively. During 2012, ComEd and BGE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of ComEd s and BGE s 2012 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010.

ComEd received a non-cash contribution to equity from Exelon in 2012 of $11, related to tax benefits associated with capital projects constructed by ComEd on behalf of Exelon and Generation.

15. Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

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 for financial accounting and reporting purposes, 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. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

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

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon s and Generation s Consolidated Balance Sheets, from January 1, 2012 to December 31, 2013:

	Exelon and Generation
Nuclear decommissioning ARO at January 1, 2012	$ 3,680
Accretion expense	231
Net increase due to changes in, and timing of, estimated future cash flows	833
Costs incurred to decommission retired plants	(3)
Nuclear decommissioning ARO at December 31, 2012 [(a)]	4,741
Accretion expense	259
Net decrease due to changes in, and timing of, estimated future cash flows	(140)
Costs incurred to decommission retired plants	(5)
Nuclear decommissioning ARO at December 31, 2013 [(a)]	$ 4,855

(a) Includes $9 million and $10 million as the current portion of the ARO at December 31, 2013 and 2012, respectively, which is included in Other current liabilities on Exelon s and Generation s Consolidated Balance Sheets.

During 2013, Generation s ARO increased by approximately $114 million. The increase is largely driven by an increase in the estimated costs to decommission the Limerick and Three Mile Island nuclear units resulting from the completion of updated decommissioning costs studies received during 2013 and an increase for accretion of the obligation. These increases in the ARO were offset by decreases to the ARO due to changes in long-term escalation rates, primarily for labor and energy costs, as well as changes in the timing of the future nominal cash flows coupled with the fact that cash flows affected by this change in timing are re-measured and discounted at current credit adjusted risk free rates (CARFRs), which have increased from the prior year. The decrease in the ARO due to the changes in, and timing of, estimated cash flows were entirely offset by decreases in Property, plant and equipment within Exelon s and Generation s Consolidated Balance Sheets.

During 2012, Generation s ARO increased by $1,061 million. The increase in the ARO was largely driven by four factors: i) changes in the timing of the future nominal cash flows resulting from an assumed five year deferral to 2025 of the acceptance date of spent nuclear fuel by the DOE coupled with the fact that; ii) cash flows affected by this change in timing are re-measured and discounted at current CARFRs, which had dramatically decreased given the lower interest rate environment; iii) an increase in the estimated costs to decommission the Quad Cities, Dresden and Clinton nuclear units resulting from the completion of updated decommissioning costs studies received during 2012; and iv) accretion of the obligation. The increase in the ARO due to the changes in, and timing of, estimated cash flows resulted in $10 million of expense, which is included in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generating station unit to satisfy Generation s nuclear decommissioning obligations. Generally, 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 is authorized to collect funds, in

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

revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO s calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual collections of approximately $24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. 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, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third-party (see Zion Station Decommissioning below). 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, and likewise Generation 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. The 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 all 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 funds after decommissioning.

During 2012, the NDT fixed income portfolio completed its transition from solely core fixed income investments to a blend of Treasury Inflation Protected Securities (TIPS), investment-grade corporate credit and middle market lending. There was no change in the equity investment strategy. At December 31, 2013, approximately 48% of the funds were invested in equity securities and 52% were invested in fixed income securities. At December 31, 2012, approximately 47% of the funds were invested in equity securities and 53% were invested in fixed income securities.

At December 31, 2013, and 2012, Exelon and Generation had NDT fund investments totaling $8,071 million and $7,248 million, respectively.

The following table provides unrealized gains (losses) on NDT funds for 2013, 2012 and 2011:

	Exelon and Generation For the Years Ended December 31,		
	2013	**2012**	**2011**
Net unrealized gains (losses) on decommissioning trust funds Regulatory Agreement Units[a]	$ 406	$ 386	$ (74)
Net unrealized gains (losses) on decommissioning trust funds Non-Regulatory Agreement Units[b][c]	146	105	(4)

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

(a) Net unrealized gains (losses) related to Generation s NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon s Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation s Consolidated Balance Sheets.
(b) Excludes $7 million, $73 million and $48 million of net unrealized gains related to the Zion Station pledged assets in 2013, 2012 and 2011, respectively. Net unrealized gains related to Zion Station pledged assets are included in the Payable for Zion Station decommissioning on Exelon s and Generation s Consolidated Balance Sheets.
(c) Net unrealized gains (losses) related to Generation s NDT funds with Non-Regulatory Agreement Units are included within Other, net in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units are eliminated within Other, net in Exelon s and Generation s Consolidated Statement of Operations and Comprehensive Income.

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 are expected to 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 and Generation s Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability. Should the expected value of the NDT fund for any former ComEd unit fall below the amount of the expected 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. As of December 31, 2013, the NDT funds of each of the former ComEd units are expected to exceed the related decommissioning obligation for each of the units. For the purposes of making this determination, the decommissioning obligation referred to is different, as described below, 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 are expected to exceed or fall short of the total estimated decommissioning obligation, decommissioning-related activities are generally offset within Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, PECO has recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability. Any changes to the PECO regulatory agreements could impact Exelon s and Generation s ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon s and Generation s results of operations and financial position could be material.

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The decommissioning-related activities related to the Clinton, Oyster Creek and Three Mile Island nuclear plants (the former AmerGen units) and the portions of the Peach Bottom nuclear plants that are not subject to regulatory agreements with respect to the NDT funds are reflected in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income, as there are no regulatory agreements associated with these units.

Refer to Note 3 Regulatory Matters and Note 25 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.

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, excluding the obligation to dispose of SNF, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. During 2013, EnergySolutions entered a definitive acquisition agreement and was acquired by another Company. Generation reviewed the acquisition as it relates to the ASA to decommission Zion Station. Based on that review, Generation determined that the acquisition will not adversely impact decommissioning activities under the ASA.

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. On July 20, 2012, ZionSolutions and Bank of New York Mellon filed a motion to dismiss the amended complaint for failing to state a claim. On July 29, 2013, United States District Court for the Northern District of Illinois dismissed the amended complaint. On August 26, 2013, the plaintiffs filed a notice of appeal with the United States Court of Appeals for the Seventh Circuit. On January 31, 2014, the United States Court of Appeals for the Seventh Circuit dismissed the appeal.

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 Generation s and 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 Generation s and 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. Generation has retained its obligation to the SNF following ZionSolutions completion of its contractual obligations, to transfer the SNF at Zion Station to the DOE for ultimate disposal, and to complete all remaining decommissioning activities associated with the SNF

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

storage facility. Generation has a liability of approximately $82 million, which is included within the nuclear decommissioning ARO at December 31, 2013. Generation also has retained NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payable to ZionSolutions, and withdrawals by ZionSolutions at December 31, 2013 and 2012:

	Exelon and Generation	
	2013	**2012**
Carrying value of Zion Station pledged assets	$ 458	$ 614
Payable to Zion Solutions [(a)]	414	564
Current portion of payable to Zion Solutions [(b)]	109	132
Withdrawals by Zion Solutions to pay decommissioning costs [(c)]	498	335

(a) Excludes a liability recorded within Exelon s and Generation s Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(b) Included in Other current liabilities within Exelon s and Generation s Consolidated Balance Sheets.
(c) Cumulative withdrawals since September 1, 2010.

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.

NRC Minimum Funding Requirements. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded on Generation s and Exelon s Consolidated Balance Sheets primarily due to differences in the type 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, 2013 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

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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, 2013 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 5% 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 5.9% to 6.7% (as compared to a historical 5-year annual average pre-tax return of approximately 11.7%).

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 April 1, 2013, Generation submitted its NRC-required biennial decommissioning funding status report as of December 31, 2012. As of December 31, 2012, Generation provided adequate funding assurance for all of its units, including Limerick Unit 1, where Generation has in place a $115 million parent guarantee to cover the NRC minimum funding assurance requirements. On October 2, 2013, the NRC issued summary findings from the NRC Staff s review of the 2013 decommissioning funding status reports for all 104 operating reactors, including the Generation operating units. Based on that review, the NRC Staff determined that Generation provided decommissioning funding assurance under the NRC regulations for all of its operating units, including Limerick Unit 1.

On January 31, 2013, Generation received a letter from the NRC indicating that the NRC has identified potential apparent violations of its regulations because of alleged inaccuracies in the Decommissioning Funding Status reports for 2005, 2006, 2007, and 2009. The NRC asserted that Generation s status reports deliberately reflected cost estimates for decommissioning its nuclear plants that were less than what the NRC says are the minimum amounts required by NRC regulations. Generation met with the NRC on April 30, 2013 for a pre-decisional enforcement conference to provide additional information to explain why Generation believes that it complied with the regulatory requirements and did not deliberately or otherwise provide incomplete or inaccurate information in its decommissioning funding status reports. While Generation does not believe that any sanction is appropriate, the ultimate outcome of this proceeding including the amount of a potential fine or sanction, if any, is uncertain. The January 31, 2013 letter from the NRC does not take issue with

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Generation s current funding status, and as reflected in Generation s April 1, 2013 decommissioning funding status report referenced above, Generation continues to provide adequate funding assurance for each of its units. In the normal course of NRC review, Generation has received a series of data requests that are unrelated to the potential apparent violations and the pre-decisional enforcement conference. Generation continues to cooperate with the NRC and provide the requested information. Generation does not have a definite date on which it will receive a response from the NRC.

In addition, on June 24, 2013, Exelon received a subpoena from the SEC requesting that Exelon provide the SEC with certain documents generally relating to Exelon and Generation s reporting and funding of the future decommissioning of Exelon s nuclear power plants. Exelon and Generation are cooperating with the SEC and providing the requested documents.

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.

Non-Nuclear Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

Generation has AROs for plant closure costs associated with its fossil and renewable generating facilities, 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, PECO and BGE have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1 Significant Accounting Policies for additional information on the Registrants accounting policy for AROs.

The following table provides a rollforward of the non-nuclear AROs reflected on the Registrants Consolidated Balance Sheets from January 1, 2012 to December 31, 2013:

	Exelon	Generation	ComEd	PECO	BGE
Non-nuclear AROs at January 1, 2012	$ 209	$ 92	$ 89	$ 28	$ 1
Net increase due to changes in, and timing of, estimated future cash flows [(a)]	27	18	8	1	7
Development projects	47	47			
Accretion expense [(b)]	13	8	4	1	
Merger with Constellation [(c)]	58	50			
Payments	(11)	(8)	(2)	(1)	
Non-nuclear AROs at December 31, 2012	343	207	99	29	8
Net increase due to changes in, and timing of, estimated future cash flows [(a)]	1	(11)			12
Development projects	2	2			
Accretion expense [(b)]	18	13	4	1	

Payments	(13)	(10)	(2)		(1)
Non-nuclear AROs at December 31, 2013 [d]	$ 351	$ 201	$ 101	$ 30	$ 19

(a) During the year ended December 31, 2013, Generation recorded an increase in operating and maintenance expense of $13 million. ComEd and PECO did not record any adjustments in operating and maintenance expense for the year ended December 31, 2013. During the year ended December 31, 2012, Generation recorded a reduction in operating and maintenance expense of $8 million. ComEd, PECO, and BGE did not record any reductions in operating and maintenance expense for the year ended December 31, 2012.

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(b) For ComEd, PECO, and BGE, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.
(c) Exelon s ARO includes $8 million of BGE costs incurred prior to the closing of Exelon s merger with Constellation. Refer to Note 4 Merger and Acquisitions for additional information.
(d) Includes $2 million, $1 million, and $0 million as the current portion of the ARO at December 31, 2013 for ComEd, PECO, and BGE, respectively, which is included in other current liabilities on Exelon s and each of the respective utilities Consolidated Balance Sheets.

16. Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

As of December 31, 2013, Exelon sponsored defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. In connection with the acquisition of Constellation in March 2012, Exelon assumed Constellation s benefit plans and its related assets. The table below shows the pension and postretirement benefit plans in which each operating company participated at December 31, 2013.

	Operating Company				
Name of Plan:	**Generation**	**ComEd**	**PECO**	**BGE**	**BSC**
Qualified Pension Plans:					
Exelon Corporation Retirement Program	X	X	X		X
Exelon Corporation Cash Balance Pension Plan	X	X	X		X
Exelon Corporation Pension Plan for Bargaining Unit Employees	X	X			X
Exelon New England Union Employees Pension Plan	X				
Exelon Employee Pension Plan for Clinton, TMI and Oyster Creek	X	X			X
Pension Plan of Constellation Energy Group, Inc.	X			X	X
Constellation Mystic Power, LLC Union Employees Pension Plan Including Plan A and Plan B	X				
Non-Qualified Pension Plans:					
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan	X	X	X		X
Exelon Corporation Supplemental Management Retirement Plan	X	X	X		X
Constellation Energy Group, Inc. Senior Executive Supplemental Plan	X			X	X
Constellation Energy Group, Inc. Supplemental Pension Plan	X			X	X
Constellation Energy Group, Inc. Benefits Restoration Plan	X			X	X
Baltimore Gas & Electric Company Executive Benefit Plan	X			X	X
Baltimore Gas & Electric Company Manager Benefit Plan	X			X	X
Other Postretirement Benefit Plans:					
PECO Energy Company Retiree Medical Plan	X		X		X
Exelon Corporation Health Care Program	X	X			X
Exelon Corporation Employees Life Insurance Plan	X	X	X		X
Constellation Energy Group, Inc. Retiree Medical Plan	X			X	X
Constellation Energy Group, Inc. Retiree Dental Plan	X			X	X
Constellation Energy Group, Inc. Employee Life Insurance Plan and Family Life Insurance Plan	X			X	X
Constellation Mystic Power, LLC Post-Employment Medical Account Savings Plan	X				
Exelon New England Union Post-Employment Medical Savings Account Plan	X				

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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 (liabilities), in accordance with the applicable authoritative guidance. The measurement date for the plans is December 31.

During the first quarter of 2013, Exelon received an updated valuation of its legacy pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2013. This valuation resulted in an increase to the pension obligation of $8 million and a decrease to the other postretirement benefit obligation of $39 million. Additionally, accumulated other comprehensive loss decreased by approximately $75 million (after tax) and regulatory assets increased by approximately $93 million. During the second quarter of 2013, Exelon received the updated valuation for the legacy Constellation pension and other postretirement obligations to reflect actual census data as of January 1, 2013. This valuation resulted in an increase to the pension obligation of $23 million and a decrease to the other postretirement benefit obligation of $12 million. Additionally, accumulated other comprehensive loss increased by approximately $2 million (after tax) and regulatory assets increased by approximately $14 million.

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	
	2013	2012	2013	2012
Change in benefit obligation:				
Net benefit obligation at beginning of year	$ 16,800	$ 13,538	$ 4,820	$ 4,062
Service cost	317	280	162	156
Interest cost	650	698	194	205
Plan participants contributions			34	34
Actuarial loss (gain)	(1,363)	1,520	(551)	313
Plan amendments	1		15	(103)
Acquisitions/divestitures		1,880		362
Curtailments		(10)		(8)
Settlements [(a)]	(69)	(169)		
Contractual termination benefits		15		6
Gross benefits paid	(877)	(952)	(223)	(219)
Federal subsidy on benefits paid				12
Net benefit obligation at end of year	$ 15,459	$ 16,800	$ 4,451	$ 4,820

Combined Notes to Consolidated Financial Statements (Continued)

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

	Pension Benefits		Other Postretirement Benefits	
	2013	**2012**	**2013**	**2012**
Change in plan assets:				
Fair value of net plan assets at beginning of year	$ 13,357	$ 11,302	$ 2,135	$ 1,797
Actual return on plan assets	821	1,484	209	197
Employer contributions	339	149	83	325
Plan participants contributions			34	34
Benefits paid [b]	(877)	(952)	(223)	(218)
Acquisitions/divestitures		1,543		
Settlements [a]	(69)	(169)		
Fair value of net plan assets at end of year	$ 13,571	$ 13,357	$ 2,238	$ 2,135

(a) Represents cash settlements only.
(b) Exelon s other postretirement benefits paid for the year ended December 31, 2012 are net of $1.3 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. In 2013, the Program was no longer accepting applications for reimbursement.

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

	Pension Benefits		Other Postretirement Benefits	
	2013	**2012**	**2013**	**2012**
Other current liabilities	$ 12	$ 15	$ 23	$ 23
Pension obligations	1,876	3,428		
Non-pension postretirement benefit obligations			2,190	2,662
Unfunded status (net benefit obligation less net plan assets)	$ 1,888	$ 3,443	$ 2,213	$ 2,685

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 a PBO or ABO in excess of plan assets.

	PBO in excess of plan assets	
	2013	**2012**

Projected benefit obligation	$ 15,452	$ 16,800
Fair value of net plan assets	13,564	13,357

	ABO in excess of plan assets	
	2013	**2012**
Projected benefit obligation	$ 15,452	$ 16,796
Accumulated benefit obligation	14,552	15,657
Fair value of net plan assets	13,564	13,353

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On a PBO basis, the plans were funded at 88% at December 31, 2013 compared to 80% at December 31, 2012. On an ABO basis, the plans were funded at 93% at December 31, 2013 compared to 85% at December 31, 2012. 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 presents the components of Exelon s net periodic benefit costs for the years ended December 31, 2013, 2012 and 2011. The table reflects an increase in 2012 and a reduction in 2011 of net periodic postretirement benefit costs of approximately $(17) million and $28 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.

The 2013 pension benefit cost for all plans is calculated using an expected long-term rate of return on plan assets of 7.50% and a discount rate of 3.92%. Certain plans were remeasured during the year using a discount rate of 4.21%. The 2013 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.45% for funded plans and a discount rate of 4.00% for all plans. Certain plans were remeasured during the year using a discount rate of 4.66%. Certain other postretirement benefit plans are not funded. A portion of the net periodic benefit cost is capitalized within the Consolidated Balance Sheets.

	Pension Benefits			Other Postretirement Benefits		
	2013	**2012**	**2011**	**2013**	**2012**	**2011**
Components of net periodic benefit cost:						
Service cost	$ 317	$ 280	$ 212	$ 162	$ 156	$ 142
Interest cost	650	698	649	194	205	207
Expected return on assets	(1,015)	(988)	(939)	(132)	(115)	(111)
Amortization of:						
Transition obligation					11	9
Prior service cost (credit)	14	15	14	(19)	(17)	(38)
Actuarial loss	562	450	331	83	81	66
Curtailment benefits					(7)	
Settlement charges	9	31				
Contractual termination benefits [(a)]		14			6	
Net periodic benefit cost	$ 537	$ 500	$ 267	$ 288	$ 320	$ 275

(a) ComEd and BGE established regulatory assets of $1 million and $4 million, respectively, for their portion of the contractual termination benefit charge in 2012.

Through Exelon s postretirement benefit plans, the Registrants provide retirees with prescription drug coverage. The Medicare Modernization Act, enacted on December 8, 2003, introduced a prescription drug benefit under Medicare as well as a Federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the Medicare prescription drug benefit. Management believes the prescription drug benefit provided under Exelon s postretirement benefit plans meets the requirements for the subsidy. In December 2011, the Company decided that beginning in 2013, it will no longer elect to take the direct Part D subsidy. Beginning in 2013, eligible employees are offered an Employee Group Waiver Plan, a Medicare Part D Plan, with a supplemental wrap that closely matches the current prescription drug plan design. See the *Health*

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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, 2013, 2012 and 2011 included in the consolidated financial statements was as follows:

	2013	2012	2011
Amortization of the actuarial experience loss	$	$ (17)	$ 3
Reduction in current period service cost			9
Reduction in interest cost on the APBO			16
Total effect of subsidy on net periodic postretirement benefit cost	$	$ (17)	$ 28

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 (liabilities) for the years ended December 31, 2013, 2012 and 2011 for all plans combined.

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):						
Current year actuarial (gain) loss	$ (1,169)	$ 1,693	$ 744	$ (628)	$ 304	$ 74
Amortization of actuarial gain (loss)	(562)	(450)	(331)	(83)	(81)	(66)
Current year prior service (credit) cost		1		15	(109)	
Amortization of prior service (cost) credit	(14)	(15)	(14)	19	17	38
Current year transition (asset) obligation					1	
Amortization of transition asset (obligation)					(11)	(9)
Curtailments		(10)			(1)	
Settlements	(8)	(31)				
Total recognized in AOCI and regulatory assets (liabilities) [(a)]	$ (1,753)	$ 1,188	$ 399	$ (677)	$ 120	$ 37

(a) Of the $1,753 million gain related to pension benefits, $1,071 million and $682 million were recognized in AOCI and regulatory assets, respectively, during 2013. Of the $677 million gain related to other postretirement benefits, $352 million and $325 million were recognized in AOCI and regulatory assets (liabilities), respectively, during 2013. Of the $1,188 million loss related to pension benefits, $283 million and $904 million were recognized in AOCI and regulatory assets, respectively, during 2012. Of the $120 million loss related to other postretirement benefits, $39 million and $81 million were recognized in

AOCI and regulatory assets, respectively, during 2012. Of the $399 million loss related to pension benefits, $181 million and $218 million were recognized in AOCI and regulatory assets, respectively, during 2011. Of the $37 million loss related to other postretirement benefits, $13 million and $24 million were recognized in AOCI and regulatory assets, respectively, during 2011.

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The following table provides the components of Exelon s gross accumulated other comprehensive loss and regulatory assets (liabilities) that have not been recognized as components of periodic benefit cost at December 31, 2013 and 2012, respectively, for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2013	**2012**	**2013**	**2012**
Prior service cost (credit)	$ 62	$ 76	$ (73)	$ (107)
Actuarial loss	6,192	7,931	474	1,185
Total [(a)]	$ 6,254	$ 8,007	$ 401	$ 1,078

(a) Of the $6,254 million related to pension benefits, $3,523 million and $2,731 million are included in AOCI and regulatory assets, respectively, at December 31, 2013. Of the $401 million related to other postretirement benefits, $161 million and $240 million are included in AOCI and regulatory assets (liabilities), respectively, at December 31, 2013. Of the $8,007 million related to pension benefits, $4,594 million and $3,413 million are included in AOCI and regulatory assets, respectively, at December 31, 2012. Of the $1,078 million related to other postretirement benefits, $514 million and $564 million are included in AOCI and regulatory assets, respectively, at December 31, 2012.

The following table provides the components of Exelon s AOCI and regulatory assets at December 31, 2013 (included in the table above) that are expected to be amortized as components of periodic benefit cost in 2014. 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, 2014 and actual claims activity as of December 31, 2013. The valuation is expected to be completed in the first quarter of 2014 for legacy Exelon plans and in the second quarter of 2014 for legacy Constellation plans.

	Pension Benefits	Other Postretirement Benefits
Prior service cost (credit)	$ 14	$ (16)
Actuarial loss	427	32
Total [(a)]	$ 441	$ 16

(a) Of the $441 million related to pension benefits at December 31, 2013, $232 million and $209 million are expected to be amortized from AOCI and regulatory assets in 2013, respectively. Of the $16 million related to other postretirement benefits at December 31, 2013, $7 million and $9 million are expected to be amortized from AOCI and regulatory assets in 2013, 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 participating in cash balance 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.

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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, 2013, 2012 and 2011. 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		
	2013	2012	2011	2013	2012	2011
Discount rate	4.80%	3.92%	4.74%	4.90%	4.00%	4.80%
Rate of compensation increase	(a)	(b)	3.75%	(a)	(b)	3.75%
Mortality table	IRS required mortality table for 2014 funding valuation	IRS required mortality table for 2013 funding valuation	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2014 funding valuation	IRS required mortality table for 2013 funding valuation	IRS required mortality table for 2012 funding valuation
Health care cost trend on covered charges	N/A	N/A	N/A	6.00% decreasing to ultimate trend of 5.00% in 2017	6.50% decreasing to ultimate trend of 5.00% in 2017	6.50% decreasing to ultimate trend of 5.00% in 2017

(a) 3.25% for 2014-2018 and 3.75% thereafter.
(b) 3.25% for 2013-2017 and 3.75% thereafter.

The following assumptions were used to determine the net periodic benefit costs for all the plans for the years ended December 31, 2013, 2012 and 2011:

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Discount rate	3.92%[(a)]	4.74%[(b)]	5.26%	4.00%[(a)]	4.80%[(b)]	5.30%
Expected return on plan assets	7.50%[(c)]	7.50%[(c)]	8.00%[(c)]	6.45%[(c)]	6.68%[(c)]	7.08%[(c)]
Rate of compensation increase	(d)	3.75%	3.75%	(d)	3.75%	3.75%
Mortality table	IRS required mortality	IRS required mortality	IRS required mortality	IRS required mortality	IRS required mortality	IRS required mortality

	table for 2013 funding valuation	table for 2012 funding valuation	table for 2011 funding valuation	table for 2013 funding valuation	table for 2012 funding valuation	table for 2011 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	6.50% decreasing to ultimate trend of 5.00% in 2017	7.00% decreasing to ultimate trend of 5.00% in 2015

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(a) The discount rates above represent the initial discount rates used to establish Exelon s pension and other postretirement benefits costs for the year ended December 31, 2013. Certain of the benefit plans were remeasured during the year using discount rates of 4.21% and 4.66% for pension and other postretirement benefits, respectively. Costs for the year ended December 31, 2013 reflect the impact of these remeasurements.
(b) The discount rates above represent the initial discounts rates used to establish Exelon s pension and other postretirement benefits costs for 2012. Certain of the benefit plans were remeasured during the year due to the Constellation merger, plan settlement and curtailment events, and plan changes using discount rates of 3.71% and 3.72% for pension and other postretirement benefits, respectively. Costs for the year ended December 31, 2012 reflect the impact of these remeasurements.
(c) Not applicable to pension and other postretirement benefit plans that do not have plan assets.
(d) 3.25% for 2013-2017 and 3.75% thereafter.

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 2013 total service and interest cost components	$ 90
on postretirement benefit obligation at December 31, 2013	858
Effect of a one percentage point decrease in assumed health care cost trend:	
on 2013 total service and interest cost components	(62)
on postretirement benefit obligation at December 31, 2013	(607)

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, the Registrants were required to recognize the full accounting impact in their financial statements in the period in which the legislation was enacted. As a result, in the first quarter of 2010, Exelon recorded total after-tax charges of approximately $65 million to income tax expense to reverse deferred tax assets previously established. Generation, ComEd, PECO and BGE recorded charges of $24 million, $11 million, $9 million and $3 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 has made a change in the manner in which it will receive prescription drug subsidies beginning in 2013.

Additionally, 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.

Combined Notes to Consolidated Financial Statements (Continued)

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

Contributions

The following table provides contributions made by Generation, ComEd, PECO, BGE and BSC to the pension and other postretirement benefit plans:

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011 [c]	2013 [a]	2012 [a]	2011 [a]
Generation	$ 119	$ 48	$ 954	$ 30	$ 135	$ 121
ComEd	118	25	873	4	119	108
PECO	11	13	110	20	33	28
BGE [b]				24	12	
BSC	91	63	157	5	24	20
Exelon	$ 339	$ 149	$ 2,094	$ 83	$ 323	$ 277

(a) The Registrants present the cash contributions above net of Federal subsidy payments received on each of their respective Consolidated Statements of Cash Flows. Exelon, Generation, ComEd, PECO, and BGE received Federal subsidy payments of $10 million, $5 million, $4 million, $1 million and $2 million, respectively, in 2012, and $11 million, $5 million, $4 million, $1 million and $3 million, respectively, in 2011. Effective January 1, 2013, Exelon is no longer receiving this subsidy.

(b) BGE s pension benefit contributions for 2012 and 2011 exclude $0 million and $54 million, respectively, of pension contributions made by BGE prior to the closing of Exelon s merger with Constellation on March 12, 2012. BGE s other postretirement benefit payments for 2012 and 2011 exclude $4 million and $13 million, respectively, of other postretirement benefit payments made by BGE prior to the closing of Exelon s merger with Constellation on March 12, 2012. These pre-merger contributions are not included in Exelon s financial statements but are reflected in BGE s financial statements.

(c) The increase in 2011 pension contributions was related to Exelon s $2.1 billion contribution to its pension plans as a result of accelerated cash benefits associated with the Tax Relief Act of 2010.

Exelon plans to contribute $264 million to its qualified pension plans in 2014, of which Generation, ComEd, PECO and BGE will contribute $118 million, $119 million, $11 million and $0 million, respectively. Unlike the qualified pension plans, Exelon s non-qualified pension plans are not funded. Exelon plans to make non-qualified pension plan benefit payments of $12 million in 2014, of which Generation, ComEd, PECO and BGE will make payments of $5 million, $1 million, $0 million and $1 million, respectively. 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). Additionally, for Exelon s largest qualified pension plan, the projected contributions reflect a funding strategy of contributing the greater of $250 million, which approximates service cost, or the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower minimum pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law were applied in 2012 while others were applied in 2013. The estimated impacts of the law are reflected in the projected pension contributions.

Unlike the qualified pension plans, other postretirement plans are not subject to statutory minimum contribution requirements. Exelon s management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and

Combined Notes to Consolidated Financial Statements (Continued)

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

best assure continued rate recovery). In 2014, Exelon anticipates funding its other postretirement benefit plans based on the funding considerations discussed above, with the exception of those plans which remain unfunded. Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $430 million in 2014, of which Generation, ComEd, PECO, and BGE expect to contribute $168 million, $197 million, $19 million, and $17 million, respectively.

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2013 were:

	Pension Benefits	Other Postretirement Benefits
2014	$ 929	$ 204
2015	851	210
2016	873	219
2017	902	228
2018	1,015	238
2019 through 2023	5,257	1,383
Total estimated future benefit payments through 2023	$ 9,827	$ 2,482

Allocation to Exelon Subsidiaries

Generation, ComEd, PECO, and BGE account for their participation in Exelon s pension and other postretirement benefit plans by applying multiemployer accounting. Employee-related assets and liabilities, including both pension and postretirement liabilities, for the legacy Exelon plans were allocated by Exelon to its subsidiaries based on the number of active employees as of January 1, 2001 as part of Exelon s corporate restructuring. Exelon allocates the components of pension and other postretirement costs to the subsidiaries in the legacy Exelon plans based upon several factors, including the measures of active employee participation in each participating unit. The obligation for Generation, ComEd and PECO reflects the initial allocation and the cumulative costs incurred and contributions made since January 1, 2001. Pension and postretirement benefit contributions are allocated to legacy Exelon subsidiaries in proportion to active service costs recognized and total costs recognized, respectively. For legacy CEG plans, components of pension and other postretirement benefit costs and contributions are allocated to the subsidiaries based on employee participation (both active and retired).

The amounts below were included in capital expenditures and operating and maintenance expense for the years ended December 31, 2013, 2012 and 2011, respectively, for Generation s, ComEd s, PECO s, BSC s and BGE s allocated portion of the pension and postretirement benefit plan costs. These amounts include the recognized contractual termination benefit charges, curtailment gains, and settlement charges:

For the Year Ended December 31,	Generation	ComEd	PECO	BSC [a]	BGE [b][c]	Exelon
2013	$ 347	$ 309	$ 43	$ 71	$ 55	$ 825
2012	341	282	50	99	60	820
2011	249	213	32	48	51	542

Combined Notes to Consolidated Financial Statements (Continued)

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

(a) These amounts primarily represent amounts billed to Exelon s subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO or BGE amounts above. As of December 31, 2012, ComEd and BGE each reported a regulatory asset of $1 million related to their BSC-billed portion of the second quarter 2012 contractual termination benefit charge.
(b) The amounts included in capital and operating and maintenance expense for the years ended December 31, 2012 and 2011 include $12 million and $51 million, respectively, in costs incurred prior to the closing of Exelon s merger with Constellation on March 12, 2012. These amounts are not included in Exelon s capital expenditures and operating and maintenance expense for the years ended December 31, 2012 and 2011.
(c) BGE s pension and other postretirement benefit costs for the year ended December 31, 2012 include a $3 million contractual termination benefit charge, which was recorded as a regulatory asset as of December 31, 2012.

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.

Exelon has developed and implemented a liability hedging investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. 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. Trust assets for Exelon s other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

Exelon used an EROA of 7.00% and 6.59% to estimate its 2014 pension and other postretirement benefit costs, respectively.

Exelon s pension and other postretirement benefit plan target asset allocations and December 31, 2013 and 2012 asset allocations were as follows:

Pension Plans

		Percentage of Plan Assets at December 31,	
Asset Category	**Target Allocation**	**2013**	**2012**
Equity securities	31%	35%	35%
Fixed income securities	38%	37	40
Alternative investments [(a)]	31%	28	25
Total		100%	100%

Other Postretirement Benefit Plans

		Percentage of Plan Assets at December 31,	
Asset Category	**Target Allocation**	**2013**	**2012**
Equity securities	41%	45%	46%
Fixed income securities	39%	37	40
Alternative investments [(a)]	20%	18	14
Total		100%	100%

Combined Notes to Consolidated Financial Statements (Continued)

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

(a) Alternative investments include private equity, hedge funds and real estate.

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, 2013. 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, 2013, 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, 2013 and 2012:

At December 31, 2013 [(a)]	Level 1	Level 2	Level 3	Total
Pension plan assets				
Equity securities:				
Individually held	3,090		2	3,092
Commingled funds		1,167		1,167
Mutual funds	270			270
Equity securities subtotal	3,360	1,167	2	4,529
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	908	9		917
Debt securities issued by states of the United States and by political subdivisions of the states		88		88
Foreign debt securities		205		205
Corporate debt securities		2,927	41	2,968
Federal agency mortgage-backed securities		90		90
Non-Federal agency mortgage-backed securities		26		26
Commingled funds		558		558
Mutual funds	5	315		320
Derivative instruments [(b)]:				
Assets		7		7
Liabilities		(134)		(134)
Fixed income securities subtotal	913	4,091	41	5,045
Private equity			806	806
Hedge funds		1,266	1,039	2,305
Real estate:				
Individually held	264			264

Commingled funds		2		2
Real estate funds			582	582
Real estate subtotal	264	2	582	848
Pension plan assets subtotal	4,537	6,526	2,470	13,533

Combined Notes to Consolidated Financial Statements (Continued)

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

At December 31, 2013 [a]	Level 1	Level 2	Level 3	Total
Other postretirement benefit plan assets				
Cash equivalents	51			51
Equity securities:				
Individually held	286			286
Commingled funds		515		515
Mutual funds	164			164
Equity securities subtotal	450	515		965
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	17	1		18
Debt securities issued by states of the United States and by political subdivisions of the states		149		149
Foreign debt securities		2		2
Corporate debt securities		50		50
Federal agency mortgage-backed securities		45		45
Non-Federal agency mortgage-backed securities		7		7
Commingled funds		218		218
Mutual funds	305			305
Fixed income securities subtotal	322	472		794
Private equity			2	2
Hedge funds		295	4	299
Real estate:				
Individually held	8			8
Real estate funds		5	109	114
Real estate subtotal	8	5	109	122
Other postretirement benefit plan assets subtotal	831	1,287	115	2,233
Total pension and other postretirement benefit plan assets [c]	$ 5,368	$ 7,813	$ 2,585	$ 15,766

Combined Notes to Consolidated Financial Statements (Continued)

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

At December 31, 2012 [(a)]	Level 1	Level 2	Level 3	Total
Pension plan assets				
Cash equivalents	$ 1	$	$	$ 1
Equity securities:				
Individually held	2,562			2,562
Commingled funds		1,111		1,111
Mutual funds	323			323
Equity securities subtotal	2,885	1,111		3,996
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,037			1,037
Debt securities issued by states of the United States and by political subdivisions of the states		108		108
Foreign debt securities		252		252
Corporate debt securities		3,330		3,330
Federal agency mortgage-backed securities		117		117
Non-Federal agency mortgage-backed securities		28		28
Commingled funds		274		274
Mutual funds	4	291		295
Derivative instruments [(b)]:				
Assets		9		9
Liabilities		(21)		(21)
Fixed income securities subtotal	1,041	4,388		5,429
Private equity			754	754
Hedge funds		1,080	1,235	2,315
Real estate:				
Individually held	280			280
Commingled funds		75		75
Real estate funds			426	426
Real estate subtotal	280	75	426	781
Pension plan assets subtotal	4,207	6,654	2,415	13,276

Combined Notes to Consolidated Financial Statements (Continued)

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

At December 31, 2012 [(a)]	Level 1	Level 2	Level 3	Total
Other postretirement benefit plan assets				
Cash equivalents	44			44
Equity securities:				
Individually held	198			198
Commingled funds		530		530
Mutual funds	230			230
Equity securities subtotal	428	530		958
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	18			18
Debt securities issued by states of the United States and by political subdivisions of the states		125		125
Foreign debt securities		3		3
Corporate debt securities		50		50
Federal agency mortgage-backed securities		52		52
Non-Federal agency mortgage-backed securities		6		6
Commingled funds		271		271
Mutual funds	295	2		297
Fixed income securities subtotal	313	509		822
Private equity			1	1
Hedge funds		188	12	200
Real estate:				
Individually held	7			7
Commingled funds		2		2
Real estate funds		6	95	101
Real estate subtotal	7	8	95	110
Other postretirement benefit plan assets subtotal	792	1,235	108	2,135
Total pension and other postretirement benefit plan assets [(c)]	$ 4,999	$ 7,889	$ 2,523	$ 15,411

(a) See Note 11 Fair Value of Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) Derivative instruments have a total notional amount of $2,651 million and $2,498 million at December 31, 2013 and 2012, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company s exposure to credit or market loss.
(c) Excludes net assets of $43 million and $81 million at December 31, 2013 and 2012, respectively, which are required to reconcile to the fair value of net plan assets. These items consist primarily of receivables related to pending securities sales, interest and dividends receivable, and payables related to pending securities purchases.

Combined Notes to Consolidated Financial Statements (Continued)

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

The following table presents the reconciliation of Level 3 assets and liabilities measured at fair value for pension and other postretirement benefit plans for the years ended December 31, 2013 and 2012:

	Hedge funds	Private equity	Real estate	Debt securities	Preferred stock	Total
Pension Assets						
Balance as of January 1, 2013	$ 1,235	$ 754	$ 426	$	$	$ 2,415
Actual return on plan assets:						
Relating to assets still held at the reporting date	143	86	63			292
Relating to assets sold during the period	3		(4)			(1)
Purchases, sales and settlements:						
Purchases	360	123	226	41	2	752
Sales	(76)		(91)			(167)
Settlements [(a)]	(3)	(157)	(38)			(198)
Transfers into (out of) Level 3 [(b)]	(623)					(623)
Balance as of December 31, 2013	$ 1,039	$ 806	$ 582	$ 41	$ 2	$ 2,470
Other Postretirement Benefits						
Balance as of January 1, 2013	$ 12	$ 1	$ 95	$	$	$ 108
Actual return on plan assets:						
Relating to assets still held at the reporting date	1		11			12
Relating to assets sold during the period						
Purchases, sales and settlements:						
Purchases		1	3			4
Sales	(1)					(1)
Settlements [(a)]	(4)					(4)
Transfers into (out of) Level 3 [(b)]	(4)					(4)
Balance as of December 31, 2013	$ 4	$ 2	$ 109	$	$	$ 115

Combined Notes to Consolidated Financial Statements (Continued)

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

	Hedge funds	Private equity	Real estate	Debt securities	Preferred stock	Total
Pension Assets						
Balance as of January 1, 2012	$ 1,525	$ 672	$ 229	$	$	$ 2,426
Actual return on plan assets:						
Relating to assets still held at the reporting date	138	55	24			217
Purchases, sales and settlements:						
Purchases	447	108	134			689
Sales	(6)					(6)
Settlements [(a)]	(4)	(128)	(28)			(160)
Transfers into (out of) Level 3 [(c)(d)(e)]	(865)	47	67			(751)
Balance as of December 31, 2012	$ 1,235	$ 754	$ 426	$	$	$ 2,415
Other Postretirement Benefits						
Balance as of January 1, 2012	$ 157	$ 1	$ 7	$	$	$ 165
Actual return on plan assets:						
Relating to assets still held at the reporting date	11		3			14
Purchases, sales and settlements:						
Purchases	32		91			123
Sales						
Settlements [(a)]			(1)			(1)
Transfers into (out of) Level 3 [(c)(d)(e)]	(188)		(5)			(193)
Balance as of December 31, 2012	$ 12	$ 1	$ 95	$	$	$ 108

(a) Represents cash settlements only.

(b) As of December 31, 2012, hedge fund investments that contained redemption restrictions limiting Exelon s ability to redeem the investments within a reasonable period of time were classified as Level 3 investments. As of December 31, 2013, restrictions for certain investments no longer applied, therefore allowing redemption within a reasonable period of time from the measurement date at NAV. As such, these hedge fund investments are reflected as transfers out of Level 3 to Level 2 of $627 million in 2013.

(c) In connection with the acquisition of Constellation in March 2012, Exelon assumed Constellation s pension plan assets resulting in transfers into Level 3 of $141 million.

(d) In 2012, Exelon refined its policy over the criteria that hedge fund investments must meet in order to be categorized within Level 2 and Level 3 of the fair value hierarchy. Therefore, certain hedge fund investments that were categorized within Level 3 in prior periods have been re-categorized as Level 2 investments as of December 31, 2012. The re-categorization of these hedge fund investments is reflected as transfers out of Level 3 of $1.1 billion.

(e) In 2012, the liquidity terms of a certain real estate investment changed to allow redemption within a reasonable period of time from the redemption date which led to a transfer out of Level 3 to Level 2 of $5 million.

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. The fair values are based on observable market prices and, therefore, 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

Combined Notes to Consolidated Financial Statements (Continued)

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

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. Certain private placement equity securities are categorized as Level 3 because they are not publicly traded and are priced using significant unobservable inputs.

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 mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. 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, which consist primarily of corporate debt securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, commingled funds, mutual funds and derivative instruments, 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. Certain private placement fixed income securities have been categorized as Level 3 because they are priced using certain significant unobservable inputs and are typically illiquid. The fair values of fixed income securities, excluding U.S. Treasury securities and privately placed fixed income 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.

Derivative instruments consisting primarily of interest rate swaps to manage risk are recorded at fair value. Derivative instruments are valued based on external price data of comparable securities and have been categorized as Level 2.

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 mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. 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.

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

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 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 or a gate. For Exelon s investments that have terms that allow redemption within a reasonable period of time from the measurement date, the hedge fund investments are categorized as Level 2. For investments that have restrictions that may limit Exelon s ability to redeem the investments at the measurement date or within a reasonable period of time, the hedge fund investments are categorized 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, these real estate funds have been categorized as Level 3.

Defined Contribution Savings Plan (Exelon, Generation, ComEd, PECO and BGE)

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents matching contributions to the savings plan for the years ended December 31, 2013, 2012 and 2011:

For the Year Ended December 31,	Exelon	Generation	ComEd	PECO	BGE [(a)]	BSC [(b)]
2013	$ 85	$ 40	$ 22	$ 8	$ 8	$ 7
2012	67	30	19	7	7	5
2011	78	40	22	9	7	7

(a) BGE s matching contributions for the years ended December 31, 2012 and 2011 include $1 million and $7 million of costs, respectively, incurred prior to the closing of Exelon s merger with Constellation on March 12, 2012. These costs are not included in Exelon s matching contributions for the years ended December 31, 2012 and 2011.

(b) These amounts primarily represent amounts billed to Exelon s subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO, or BGE amounts above.

17. Severance (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. The Registrants record a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan (one-time termination benefits), the Registrants measure the obligation and record the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

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

Merger-Related Severance

Upon closing the merger with Constellation, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. The majority of these positions are corporate and Generation support positions. Since then, Exelon has identified specific employees to be severed pursuant to the merger-related staffing and selection process as well as employees that were previously identified for severance but have since accepted another position within Exelon and are no longer receiving a severance benefit. Exelon adjusts its accrual each quarter to reflect its best estimate of remaining severance costs. In addition, certain employees identified during the staffing and selection process also receive pension and other postretirement benefits that are deemed contractual termination benefits, which the Registrants recorded during the second quarter of 2012.

The amount of severance expense associated with the post-merger integration recognized for the year ended December 31, 2013 for Exelon and Generation was $6 million and $6 million, respectively. For Generation, $5 million represents amounts billed by BSC through intercompany allocations. There was no severance expense associated with post-merger integration recognized for the year ended December 31, 2013 for ComEd, PECO and BGE. Estimated costs to be incurred after December 31, 2013 are not material.

For the year ended December 31, 2012, the Registrants recorded the following severance benefit costs associated with the identified job reductions within operating and maintenance expense in their Consolidated Statements of Operations, except for those costs that were capitalized as regulatory assets related to ComEd and BGE:

Year Ended December 31, 2012

Severance Benefits [(a)]	**Exelon** [(b)]	**Generation**	**ComEd** [(b)]	**PECO**	**BGE** [(b)]
Severance charges	$ 124	$ 80	$ 14	$ 7	$ 17
Stock compensation	7	4	1		1
Other charges	7	4	1		1
Total severance benefits	$ 138	$ 88	$ 16	$ 7	$ 19

(a) The amounts above include $46 million at Generation, $14 million at ComEd, $7 million at PECO, and $7 million at BGE, for amounts billed by BSC through intercompany allocations for the year ended December 31, 2012.

(b) Exelon, ComEd and BGE established regulatory assets of $35 million, $16 million and $19 million, respectively, for severance benefits costs for the year ended December 31, 2012. The majority of these costs are expected to be recovered over a five-year period.

Combined Notes to Consolidated Financial Statements (Continued)

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

Amounts included in the table below represent the severance liability recorded by Exelon, Generation, ComEd, PECO and BGE for employees of those Registrants and exclude amounts billed through intercompany allocations:

Severance liability	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Balance at December 31, 2011	$	$	$	$	$
Severance charges [(a)]	124	38	2		11
Stock compensation	7	2			
Other charges [(b)]	7	2			1
Payments	(27)	(9)	(1)		(1)
Balance at December 31, 2012	$ 111	$ 33	$ 1	$	$ 11
Severance charges	5	1			
Stock compensation	1				
Payments	(64)	(24)	(1)		(5)
Balance at December 31, 2013	$ 53	$ 10	$	$	$ 6

(a) Includes salary continuance and health and welfare severance benefits. Amounts primarily represent benefits provided for under Exelon s ongoing severance plan. One-time termination benefits were not material for the years ended December 31, 2012 and December 31, 2013.
(b) Primarily includes life insurance, employer payroll taxes, educational assistance, and outplacement services.

Cash payments under the plan began in the second quarter of 2012. Substantially all cash payments under the plan are expected to be made by the end of 2016.

Ongoing Severance Plans

The Registrants provide severance and health and welfare benefits under Exelon s ongoing severance benefit plans to terminated employees in the normal course of business, which were not directly related to the merger with Constellation. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

For the years ended December 31, 2013, 2012, and 2011, the Registrants recorded the following severance costs associated with these ongoing severance benefits within operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income:

Severance Benefits [(a)]	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Severance charges 2013	$ 18	$ 16	$ 2	$	$
Severance charges 2012	19	14	2	1	3
Severance charges 2011	5	5			4

(a) The amounts above for Generation include $2 million, $0 million, and $1 million for amounts billed by BSC through intercompany allocations for the years ended December 31, 2013, December 31, 2012, and December 31, 2011, respectively. Amounts billed by BSC to ComEd, PECO and BGE were not material.

The severance liability balances associated with these ongoing severance benefits as of December 31, 2013 and 2012 are not material.

Combined Notes to Consolidated Financial Statements (Continued)

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

18. Preferred and Preference Securities (Exelon, ComEd, PECO and BGE)

At December 31, 2013 and 2012, 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, 2013 and 2012, 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, 2012, 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. On May 1, 2013, PECO redeemed all of its outstanding preferred securities. PECO had $87 million of cumulative preferred securities that were redeemable at its option at any time for the redemption price established when each series was issued. The redemption premium is treated as a reduction to Net income to arrive at Net income attributable to common shareholders utilized in the calculation of the earnings per share for Exelon.

		December 31,			
	Redemption Price [(a)]	2013	2012	2013	2012
		Shares Outstanding		Dollar Amount	
Series (without mandatory redemption)					
$4.68 (Series D)	$ 104.00		150,000	$	$ 15
$4.40 (Series C)	112.50		274,720		27
$4.30 (Series B)	102.00		150,000		15
$3.80 (Series A)	106.00		300,000		30
Total preferred securities			874,720	$	$ 87

(a) Redeemable, at the option of PECO, at the indicated dollar amounts per share, plus accrued dividends.

At December 31, 2013 and 2012, BGE cumulative preference stock, $100 par value, consisted of 6,500,000 shares authorized and the outstanding amounts set forth below. Shares of BGE preference stock have no voting power except for the following:

The preference stock has one vote per share on any charter amendment which would create or authorize any shares of stock ranking prior to or on a parity with the preference stock as to either dividends or distribution of assets, or which would substantially adversely affect the contract rights, as expressly set forth in BGE s charter, of the preference stock, each of which requires the affirmative vote of two-thirds of all the shares of preference stock outstanding; and

Whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.

Combined Notes to Consolidated Financial Statements (Continued)

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

	Redemption Price [a]	December 31, 2013	2012	2013	2012
		Shares Outstanding		Dollar Amount	
Series (without mandatory redemption)					
7.125%, 1993 Series	$ 100.00	400,000	400,000	$ 40	$ 40
6.97%, 1993 Series	100.00	500,000	500,000	50	50
6.70%, 1993 Series	100.34	400,000	400,000	40	40
6.99%, 1995 Series	100.70	600,000	600,000	60	60
Total preference stock		1,900,000	1,900,000	$ 190	$ 190

(a) Redeemable, at the option of BGE, at the indicated dollar amounts per share, plus accrued and unpaid dividends.

19. Common Stock (Exelon, Generation, ComEd, PECO and BGE)

The following table presents common stock authorized and outstanding as of December 31, 2013 and 2012:

	Par Value	Shares Authorized	December 31, 2013	2012
			Shares Outstanding	
Common Stock				
Exelon	no par value	2,000,000,000	857,290,484	854,781,389
ComEd	$12.50	250,000,000	127,016,896	127,016,761
PECO	no par value	500,000,000	170,478,507	170,478,507
BGE	no par value	175,000,000	1,000	1,000

ComEd had 73,709 and 74,182 warrants outstanding to purchase ComEd common stock at December 31, 2013 and 2012, 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, 2013 and 2012, 24,570 and 24,727 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. In 2008, Exelon management decided to defer indefinitely any share repurchases. Any shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon s management. Under the share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion at December 31, 2013. During 2013, 2012 and 2011, Exelon had no common stock repurchases.

Combined Notes to Consolidated Financial Statements (Continued)

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

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes stock options, restricted stock units and performance share awards. At December 31, 2013, there were approximately 16 million shares authorized for issuance under the LTIP. For the years ended December 31, 2013, 2012 and 2011, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

The Compensation Committee of Exelon s Board of Directors changed the mix of awards granted under the LTIP in 2013 by eliminating stock options in favor of the use of full value shares, consisting of performance shares and restricted stock. The performance share awards granted in 2013 will cliff vest at the end of a three-year performance period. The performance share awards granted in 2012 and earlier had a one-year performance period and vested ratably over three years. To address the reduction in annual award opportunity resulting from the transition to a three-year cliff vesting performance period, the Compensation Committee also approved a one-time grant of performance share transition awards in 2013, which will vest one-third after one year, with the remaining balance vesting over a two-year performance period.

The following table presents the stock-based compensation expense included in Exelon s Consolidated Statements of Operations for the years ended December 31, 2013, 2012 and 2011:

Components of Stock-Based Compensation Expense	**Year Ended December 31, 2013**	**2012**	**2011**
Performance share awards	$ 48	$ 46	$ 26
Restricted stock units	61	50	31
Stock options	3	15	8
Other stock-based awards	6	4	4
Total stock-based compensation expense included in operating and maintenance expense	118	115	69
Income tax benefit	(44)	(44)	(27)
Total after-tax stock-based compensation expense	$ 74	$ 71	$ 42

The following table presents stock-based compensation expense (pre-tax) for the years ended December 31, 2013, 2012 and 2011:

Subsidiaries	**Year Ended December 31, 2013**	**2012 (a)**	**2011 (d)**
Generation	$ 48	$ 42	$ 31
ComEd	9	11	5
PECO	5	5	5
BGE	6	5	6
BSC (b)	50	52	28

Total [c]	$ 118	$ 115	$ 69

(a) BGE s stock-based compensation expense (pre-tax) for December 31, 2012 excludes $2 million of cost incurred in 2012 prior to the closing of Exelon s merger with Constellation on March 12, 2012. This amount is not included in Exelon s stock-based compensation expense for the year ended December 31, 2012 shown in the tables titled Components of Stock-Based Compensation Expense and Subsidiaries above.

Combined Notes to Consolidated Financial Statements (Continued)

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

(b) These amounts primarily represent amounts billed to Exelon s subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO and BGE amounts above.

(c) The stock-based compensation expense (pre-tax) for December 31, 2013 reflects the impact of changes to the retirement eligibility requirements for employees participating in the LTIP. In addition, the stock-based compensation expense at ComEd does not reflect the impact of the ComEd Key Manager Long-Term Performance Program in 2013 for certain employees, which is not considered stock-based compensation expense under the applicable authoritative guidance. In 2012, these employees participated in the Exelon Restricted Stock Award Program.

(d) The total stock-based compensation expense (pre-tax) for December 31, 2011 of $69 million does not include the $6 million expense for BGE as those costs were incurred prior to the closing of Exelon s merger with Constellation on March 12, 2012.

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2013, 2012 and 2011.

Exelon receives a tax deduction based on the intrinsic value of the award on the exercise date for stock options and the 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, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Realized tax benefit when exercised/distributed:			
Stock options	$	$ 3	$ 2
Restricted stock units	11	11	8
Performance share awards	11	7	7
Stock deferral plan	1		1
Excess tax benefits included in other financing activities of Exelon s			
Consolidated Statements of Cash Flows:			
Stock options	$	$ 2	$ 1

Stock Options

Non-qualified stock options to purchase shares of Exelon s common stock are granted under the LTIP. The exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. The vesting period of stock options is generally four years. All stock options expire ten years from the date of grant.

There were no stock options granted in 2013. The Compensation Committee eliminated stock option grants by changing the mix of long-term incentives for senior vice presidents (SVPs) and higher officers from 75% performance shares and 25% stock options to 67% performance shares and 33% restricted stock units.

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.

Combined Notes to Consolidated Financial Statements (Continued)

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

Historically, Exelon has granted most of its stock options in the first quarter of each year. Stock options granted during the remaining quarters of 2012 and 2011 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 2012 and 2011:

	Year Ended December 31,	
	2012	**2011**
Dividend yield	5.28%	4.84%
Expected volatility	23.20%	24.40%
Risk-free interest rate	1.30%	2.65%
Expected life (years)	6.25	6.25
Weighted average grant date fair value (per share)	$ 4.18	$ 6.22

The assumptions above relate to Exelon stock options granted during the periods presented and therefore do not include stock options that were converted in connection with the merger with Constellation during the year ended 2012.

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, 2013:

	Shares	**Weighted Average Exercise Price (per share)**	**Weighted Average Remaining Contractual Life (years)**	**Aggregate Intrinsic Value**
Balance of shares outstanding at December 31, 2012	21,903,781	$ 45.91		
Options reinstated	751,122	38.60		
Options exercised	(670,957)	28.02		
Options forfeited	(54,743)	39.36		
Options expired	(893,758)	49.08		

Balance of shares outstanding at December 31, 2013	21,035,445	$	46.07	4.72	$ 10
Exercisable at December 31, 2013 (a)	20,188,327	$	46.31	4.58	$ 10

(a) Includes stock options issued to retirement eligible employees.

Combined Notes to Consolidated Financial Statements (Continued)

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

The following table summarizes additional information regarding stock options exercised for the years ended December 31, 2013, 2012 and 2011:

		Year Ended December 31,	
	2013	**2012**	**2011**
Intrinsic value [(a)]	$ 4	$ 19	$ 5
Cash received for exercise price	19	47	13

(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, 2013:

	Shares	Weighted Average Exercise Price (per share)
Nonvested at December 31, 2012 (a)	1,960,665	$ 40.56
Vested	(1,058,804)	40.89
Forfeited	(54,743)	39.36
Nonvested at December 31, 2013 (a)	847,118	$ 40.22

(a) Excludes 1,348,913 and 2,647,536 of stock options issued to retirement-eligible employees as of December 31, 2013 and December 31, 2012, respectively, as they are fully vested.

At December 31, 2013, $2 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 1.6 years.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued.

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, 2013:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2012 (a)	2,029,161	$ 42.12
Granted	2,828,187	31.06
Vested	(842,439)	42.90
Forfeited	(108,199)	36.37
Undistributed vested awards (b)	(520,013)	32.62
Nonvested at December 31, 2013 (a)	3,386,697	$ 34.10

Combined Notes to Consolidated Financial Statements (Continued)

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

(a) Excludes 931,628 and 686,121 of restricted stock units issued to retirement-eligible employees as of December 31, 2013 and December 31, 2012, respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2013.

The weighted average grant date fair value (per share) of restricted stock units granted for the years ended December 31, 2013, 2012 and 2011 was $31.06, $39.94 and $43.33, respectively. At December 31, 2013 and 2012, Exelon had obligations related to outstanding restricted stock units not yet settled of $77 million and $58 million, respectively, which are included in common stock in Exelon s Consolidated Balance Sheets. For the years ended December 31, 2013, 2012 and 2011, Exelon settled restricted stock units with fair value totaling $28 million, $25 million and $19 million, respectively. At December 31, 2013, $64 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.5 years.

Performance Share Awards

Performance share awards are granted under the LTIP. The 2013 and 2012 performance share awards are being settled 50% in common stock and 50% in cash at the end of the three-year performance period except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. The performance shares granted prior to 2012 generally vest and settle over a three-year period with the holders receiving shares of common stock and/or cash annually during the vesting period.

The one-time 2013 performance share transition awards, which provide an opportunity to earn an award contingent on company performance, will be settled 50% in common stock and 50% in cash, except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. One-third of the award vests and is payable after a one-year performance period while the remaining two-thirds vests and is payable after a two-year performance period.

The payout of the 2013 performance share awards and one-time performance share transition awards are based on the Company s performance against specific operational and financial goals set annually during the respective performance periods. As a result, the 2013 performance share awards have been divided into equal tranches for the purpose of expense recognition as though the respective award were multiple awards; with each tranche representing a corresponding fiscal year. The one-time performance share transition awards have also been divided into multiple tranches for the purpose of expense recognition. One tranche reflects the one-third of the awards that vests and are payable after a one-year period. The two-thirds of the one-time performance share transition awards that are subject to a two-year performance period have also been divided into equal tranches; with each tranche representing a corresponding fiscal year. The grant date for each tranche of the 2013 performance share and one-time performance share transition awards is the date in which the performance goals for that fiscal year are approved and communicated, which typically occurs at the corresponding January Compensation Committee meeting.

The 2013 performance share awards and one-time performance share transition awards are recorded at fair value at the grant dates for each tranche, with the estimated grant date fair value based on the expected payout of the award, which may range from 50% to 150% of the payout target. The 2013 performance share awards also include a total shareholder return modifier (TSR) that may increase or decrease the award up to 25% and an individual performance modifier (IPM) that can

Combined Notes to Consolidated Financial Statements (Continued)

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

decrease the award by up to 50% or increase the award by up to 10% for SVPs and higher officers or up to 20% for vice presidents. The one-time performance share transition award is not affected by either TSR or the IPM.

The common stock portion of the performance share and one-time performance share transition awards is considered an equity award being valued based on Exelon s stock price on the grant date. The cash portion of the awards is considered a liability award which is remeasured each reporting period based on Exelon s current stock price. As the value of the common stock and cash portions of the awards are based on Exelon s stock price during the performance period, coupled with changes in the total shareholder return modifier and expected payout of the award, the compensation costs are subject to volatility until payout is established.

The 2012 performance share awards are recorded at fair value at the date of grant with the estimated grant date fair value based on the expected payout of the award, which may range from 75% to 125% of the payout target. The common stock portion is considered an equity award with the 75% payout floor being valued based on Exelon s stock price on the grant date. The cash portion of the award is considered a liability award with the 75% payout floor being remeasured each reporting period based on Exelon s current stock price. The expected payout in excess of the 75% floor for the equity and liability portions are remeasured each reporting period based on Exelon s current stock price and changes in the expected payout of the award; therefore these portions of the award are subject to volatility until the payout is established.

For nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method. For performance share and one-time performance share transition awards granted to retirement-eligible employees, the value of the performance shares in 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, 2013:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2012 (a)	1,312,734	$ 40.08
Granted	2,629,171	31.55
Vested	(612,624)	40.13
Forfeited	(24,451)	32.17
Undistributed vested awards (b)	(1,290,640)	34.28
Nonvested at December 31, 2013 (a)	2,014,190	$ 32.74

(a) Excludes 1,411,824 and 204,643 of performance share awards issued to retirement-eligible employees as of December 31, 2013 and December 31, 2012, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2013.

The weighted average grant date fair value (per share) of performance share awards granted during the years ended December 31, 2013, 2012 and 2011 was $31.55, $39.71, and $43.52, respectively. During the years ended December 31, 2013, 2012 and 2011, Exelon settled performance shares with a fair value totaling $26 million, $23 million and $22 million, respectively, of which $12 million, $3 million and $10 million was paid in cash, respectively. As of December 31, 2013, $34 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.7 years.

Combined Notes to Consolidated Financial Statements (Continued)

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

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

	December 31,	
	2013	2012
Current liabilities [a]	$ 13	$ 7
Deferred credits and other liabilities [b]	24	11
Common stock	32	35
Total	$ 69	$ 53

(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.

20. Earnings Per Share and Equity (Exelon)

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,		
	2013	2012	2011
Net income attributable to common shareholders	$ 1,719	$ 1,160	$ 2,495
Weighted average common shares outstanding basic	856	816	663
Assumed exercise and/or distributions of stock-based awards	4	3	2
Weighted average common shares outstanding diluted	860	819	665

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 20 million in 2013, 14 million in 2012 and 9 million in 2011.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of December 31, 2013. In 2008, Exelon management decided to defer indefinitely any share repurchases.

Preferred Securities Redemption (Exelon and PECO)

On May 1, 2013, PECO redeemed all of its outstanding preferred securities. PECO had $87 million of cumulative preferred securities that were redeemable at its option at any time for the redemption price established when each series of securities were issued. The redemption premium of $6 million is treated as a reduction to Net income to arrive at Net income attributable to common shareholders utilized in the calculation of earnings per share for Exelon for the year ending December 31, 2013. As a result of the redemption, PECO is now indirectly, wholly-owned by Exelon.

Combined Notes to Consolidated Financial Statements (Continued)

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

21. Changes in Accumulated Other Comprehensive Income (Exelon, Generation, and PECO)

The following table presents changes in accumulated other comprehensive income (loss) (AOCI) by component for the year ended December 31, 2013:

	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon [a]						
Beginning balance	$ 368	$	$ (3,137)	$	$ 2	$ (2,767)
OCI before reclassifications	29	2	669	(10)	101	791
Amounts reclassified from AOCI [b]	(277)		208		5	(64)
Net current-period OCI	(248)	2	877	(10)	106	727
Ending balance	$ 120	$ 2	$ (2,260)	$ (10)	$ 108	$ (2,040)
Generation [a]						
Beginning balance	$ 512	$	$	$	$ 1	$ 513
OCI before reclassifications	15	2		(10)	102	109
Amounts reclassified from AOCI [b]	(413)				5	(408)
Net current-period OCI	(398)	2		(10)	107	(299)
Ending balance	$ 114	$ 2	$	$ (10)	$ 108	$ 214
PECO [a]						
Beginning balance	$	$ 1	$	$	$	$ 1
OCI before reclassifications						
Amounts reclassified from AOCI [b]						
Net current-period OCI						
Ending balance	$	$ 1	$	$	$	$ 1

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.
(b) See next table for details about these reclassifications.

Combined Notes to Consolidated Financial Statements (Continued)

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

ComEd, PECO, and BGE did not have any reclassifications out of AOCI to Net Income during the year ended December 31, 2013. The following table presents amounts reclassified out of AOCI to Net Income for Exelon and Generation during the year ended December 31, 2013:

Details about AOCI components	**Items reclassified out of AOCI [(a)]**		**Affected line item in the statement where Net Income is presented**
	Exelon	**Generation**	
Gains and (losses) on cash flow hedges			
Energy related hedges	$ 464	$ 683	Operating revenues
Other cash flow hedges	(3)		Interest expense
	461	683	Total before tax
	(184)	(270)	Tax expense
	$ 277	$ 413	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs	$ (2)	$	(b)
Actuarial losses	(339)		(b)
Deferred compensation unit plan	(1)		(c)
	(342)		Total before tax
	134		Tax benefit
	$ (208)	$	Net of tax
Equity investments			
Capital activity	$ (8)	$ (8)	Equity in losses of unconsolidated affiliates
	(8)	(8)	Total before tax
	3	3	Tax benefit
	$ (5)	$ (5)	Net of tax
Total Reclassifications	$ 64	$ 408	Net of Tax

(a) Amounts in parenthesis represent a decrease in net income.
(b) This accumulated other comprehensive income component is included in the computation of net periodic pension and OPEB cost (see note 16 for additional details).
(c) Amortization of the deferred compensation unit plan is allocated to capital and operating and maintenance expense.

22. Commitments and Contingencies (Exelon, Generation, ComEd, PECO and BGE)

Nuclear Insurance

Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions.

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, 2013, the current liability limit per incident was $13.6 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

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every 5 years and the last inflation adjustment was made effective September 10, 2013. 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, 2013, 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 $13.2 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 $127.3 million, payable at no more than $19 million per reactor per incident per year. Exelon s maximum liability per incident is approximately $2.4 billion.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.6 billion limit for a single incident.

Generation is required each year to report to the NRC the current levels and sources of property 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 property 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. NEIL declared a distribution for 2013, of which Generation s portion was $18.5 million. The distribution was recorded as a reduction to Operating and maintenance expense within Exelon and Generation s Consolidated Statements of Operations and Comprehensive Income. No distributions were declared in 2011 or 2012. Premiums paid to NEIL by its members are subject to assessment for adverse loss experience (the retrospective premium obligation). 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, as of December 31, 2013, the current maximum aggregate annual retrospective premium obligation for Generation is approximately $287 million.

NEIL provides all risk 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. As of December 31, 2013, 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 $229 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

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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 $58 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.

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.

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. On November 19, 2013, the United States Court of Appeals for the District of Columbia Circuit ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. On January 3, 2014, the DOE filed a petition for rehearing. On the same date, as ordered by the court, the DOE submitted a proposal to Congress to reduce the current SNF disposal fee to zero, subject to any further judicial decision. The DOE s submitted proposal becomes effective after the 90-days of continuous session of the Congress unless there is Congressional action contrary to the DOE proposal. However, if the court grants the petition for rehearing, the proposal to eliminate the fee (and the review period) will be held in suspense until after the court rules. Until such time as a new fee structure is in effect, Generation must continue to pay the current SNF disposal fees.

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 devised a new strategy for long-term SNF management. A Blue Ribbon Commission (BRC) on America s Nuclear

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Future, appointed by the U.S. Energy Secretary, released a report 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.

In early 2013, the DOE issued an updated Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste in response to the BRC recommendations. This strategy included a consolidated interim storage facility that is planned to be operational in 2025.

Generation uses the 2025 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, Clinton, Limerick, Oyster Creek, Peach Bottom, Byron, Braidwood, LaSalle and Quad Cities stations.

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, 2013, totaling approximately $712 million ($601 million after considering amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek). As of December 31, 2013, the amount of SNF storage costs for which reimbursement will be requested from the DOE under the settlement agreement is $71 million, which is recorded within Accounts receivable, other. Of this amount, $18 million represents amounts owed to the co-owners of the Peach Bottom and Quad Cities generating facilities.

CENG entered into settlement agreements with the DOE during 2011 and 2012 to recover damages caused by the DOE s failure to comply with legal and contractual obligations to dispose of spent nuclear fuel related to the Ginna, Calvert Cliffs and Nine Mile Point nuclear power plants. At December 31, 2012, Generation had approximately $22 million recorded as a receivable from CENG with respect to costs incurred by Constellation prior to the formation of the CENG joint venture for the Nine Mile Point and Calvert Cliffs nuclear power plants. CENG received the funds for the Nine Mile Point and Calvert Cliffs settlement from the DOE in January 2013 and February 2013, respectively, and remitted the $22 million to Generation.

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, 2013, the unfunded SNF liability for the one-time fee with interest was $1,021 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, 2013, was 0.051%. The liabilities for SNF disposal costs, including the one-time fee, were transferred to Generation as part of Exelon s 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 11 Fair Value of Assets and Liabilities for additional information.

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Energy Commitments

Generation s customer facing activities include the physical delivery and marketing of power obtained through its generation capacity, and long-, intermediate- and short-term contracts. Generation maintains an effective supply strategy through ownership of generation assets and power purchase and lease agreements. 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. In addition to physical contracts, Generation uses financial contracts for economic hedging purposes and, to a lesser extent, as part of proprietary trading 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 market participants who primarily focus on the resale of energy products for delivery. Generation provides for delivery of its energy to these customers through firm transmission.

As part of reaching a comprehensive agreement with EDF in October 2010, the existing power purchase agreements with CENG were modified to be unit-contingent through the end of their original term in 2014. Under these agreements, CENG has the ability to fix the energy price on a forward basis by entering into monthly energy hedge transactions for a portion of the future sale, while any unhedged portions will be provided at market prices by default. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, Generation agreed to purchase 50.01% of the nuclear plant output owned by CENG at market prices. Generation discloses in the table below commitments to purchase from CENG at fixed prices. All commitments to purchase at market prices, which include all purchases subsequent to December 31, 2014, are excluded from the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 5 Investment in Constellation Energy Nuclear Group, LLC and Note 25 Related Party Transactions for more details on this arrangement.

At December 31, 2013, Generation s short- and long-term commitments, relating to the purchases from unaffiliated utilities and others of energy, capacity and transmission rights, are as indicated in the following tables:

	Net Capacity Purchases [(a)]	REC Purchases [(b)]	Transmission Rights Purchases [(c)]	Purchased Energy from CENG	Total
2014	$ 412	$ 117	$ 25	$ 824	$ 1,378
2015	367	110	13		490
2016	284	76	2		362
2017	223	25	2		250
2018	112	3	2		117
Thereafter	414	3	32		449

Total	$ 1,812	$ 334	$ 76	$ 824	$ 3,046

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

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation s expected payments under these arrangements at December 31, 2013, net of fixed capacity payments expected to be received by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. Expected payments include certain fixed capacity charges which may be reduced based on plant availability.
(b) The table excludes renewable energy purchases 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 purchases its expected energy requirements through an ICC approved competitive bidding process administered by the IPA and spot market purchases. See Note 3 Regulatory Matters for further information.

Since 2009, PECO has 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 2016. See Note 3 Regulatory Matters for further information regarding the DSP Programs.

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 established by the AEPS Act. BGE is subject to requirements established by the Public Utilities Article in Maryland related to the use of alternative energy resources; however, the wholesale suppliers that supply power to BGE through SOS procurement auctions have the obligation, by contract with BGE, to meet the RPS requirement. BGE has entered into contracts with curtailment services providers in accordance with the March 2009 MDPSC order. See Note 3 Regulatory Matters for additional information relating to electric generation procurement, alternative energy resources and energy efficiency programs.

ComEd s, PECO s and BGE s electric supply procurement, curtailment services, REC and AEC purchase commitments as of December 31, 2013 are as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
ComEd							
Electric supply procurement [(a)]	$ 736	$ 323	$ 136	$ 137	$ 140	$	$
Renewable energy and RECs [(b)]	1,589	72	74	76	77	83	1,207
PECO							
Electric supply procurement [(c)]	681	590	91				
AECs [(d)]	14	2	2	2	2	2	4
BGE							
Electric supply procurement [(e)]	1,256	783	400	73			
Curtailment services [(f)]	132	45	40	34	13		

(a)

ComEd entered into various contracts for the procurement of electricity that started to expire in 2012, and will continue to expire through 2017. ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. See Note 3 Regulatory Matters for additional information.

(b) ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC s Order on December 19, 2012, ComEd s commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC s December 18, 2013 order approved the reduction of ComEd s commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Note 3 Regulatory Matters for additional information.

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

(c) PECO entered into various contracts for the procurement of electric supply to serve its default service customers that expire between 2014 and 2015. PECO is permitted to recover its electric supply procurement costs from default service customers with no mark-up in accordance with its PAPUC-approved DSP Programs. See Note 3 Regulatory Matters for additional information.
(d) PECO is subject to requirements related to the use of alternative energy resources established by the AEPS Act. See Note 3 Regulatory Matters for additional information.
(e) BGE entered into various contracts for the procurement of electricity beginning 2013 through 2016. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 3 Regulatory Matters for additional information.
(f) BGE has entered into various contracts with curtailment services providers related to transactions in PJM s capacity market. See Note 3 Regulatory Matters 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. PECO and BGE have commitments to purchase natural gas, related transportation, storage capacity and services to serve customers in their gas distribution service territory. As of December 31, 2013, these net commitments were as follows:

		Expiration within					
	Total	**2014**	**2015**	**2016**	**2017**	**2018**	**2019 and beyond**
Generation	$ 8,490	$ 1,212	$ 1,256	$ 1,040	$ 1,044	$ 763	$ 3,175
PECO	507	179	112	98	37	15	66
BGE	609	129	59	57	57	51	256

Other Purchase Obligations

The Registrants other purchase obligations as of December 31, 2013, which primarily represent commitments for services, materials and information technology, are as follows:

		Expiration within					
	Total	**2014**	**2015**	**2016**	**2017**	**2018**	**2019 and beyond**
Exelon	$ 262	$ 61	$ 34	$ 32	$ 31	$ 26	$ 78
Generation	504	170	131	45	42	30	86
ComEd [(a)]	122	88	5	5	5	5	14
PECO [(a)]	40	30	1	1	1	1	6
BGE [(a)]	53	44	2	5	2		

(a) Purchase obligations include commitments related to smart meter installation. See Note 3 - Regulatory Matters for additional information.

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Commercial Commitments

Exelon s commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

				Expiration within			
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) [(a)]	$ 1,520	$ 1,217	$ 298	$	$ 5	$	$
Surety bonds [(b)]	339	301	2	6	4	1	25
Performance guarantees [(c)]	1,107	350					757
Energy marketing contract guarantees [(d)]	3,161	3,161					
Lease guarantees [(e)]	44						44
Nuclear insurance premiums [(f)]	3,529						3,529
Total commercial commitments	$ 9,700	$ 5,029	$ 300	$ 6	$ 9	$ 1	$ 4,355

(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.

(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, including $211 million issued on behalf of CENG nuclear generating facilities for credit support, $200 million of Trust Preferred Securities of ComEd Financing III, $178 million of Trust Preferred Securities of PECO Trust III and IV and $250 million of Trust Preferred Securities of BGE Capital Trust II.

(d) Energy marketing contract guarantees Guarantees issued to ensure performance under energy commodity contracts. Amount includes approximately $3 billion of guarantees previously issued by Constellation on behalf of its Generation and NewEnergy business to allow it the flexibility needed to conduct business with counterparties without having to post other forms of collateral. The majority of these guarantees contain evergreen provisions that require the guarantee to remain in effect until cancelled. Exelon s estimated net exposure for obligations under commercial transactions covered by these guarantees is approximately $463 million at December 31, 2013, which represents the total amount Exelon could be required to fund based on December 31, 2013 market prices.

(e) Lease guarantees Guarantees issued to ensure payments on building leases.

(f) Nuclear insurance premiums Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation s nuclear insurance premiums.

Generation s commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

				Expiration within			
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) [(a)]	$ 1,477	$ 1,174	$ 298	$	$ 5	$	$
Performance guarantees [(b)]	357	343					14
Energy marketing contract guarantees [(c)]	832	832					
Nuclear insurance premiums [(d)]	3,529						3,529

Total commercial commitments	$ 6,195	$ 2,349	$ 298	$	$ 5	$	$ 3,543

(a) Letters of credit (non-debt) Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.
(b) Performance guarantees Guarantees issued to ensure performance under specific contracts including $211 million issued on behalf of CENG nuclear generating facilities for credit support.

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

(c) Energy marketing contract guarantees Guarantees issued to ensure performance under energy commodity contracts. Amount includes approximately $749 million of guarantees previously issued by Constellation on behalf of its Generation and NewEnergy business to allow it the flexibility needed to conduct business with counterparties without having to post other forms of collateral. The majority of these guarantees contain evergreen provisions that require the guarantee to remain in effect until cancelled. Generation s estimated net exposure for obligations under commercial transactions covered by these guarantees is approximately $0.2 billion at December 31, 2013, which represents the total amount Generation could be required to fund based on December 31, 2013 market prices.

(d) 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 Nuclear Insurance section within this note for additional details on Generation s nuclear insurance premiums.

ComEd s commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

				Expiration within			
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) [(a)]	$ 19	$ 19	$	$	$	$	$
Surety bonds [(b)]	9	9					
Performance guarantees [(c)]	200						200
Total commercial commitments	$ 228	$ 28	$	$	$	$	$ 200

(a) Letters of credit (non-debt) ComEd maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantees Reflects full and unconditional guarantee of Trust Preferred Securities of ComEd Financing III which is a 100% owned finance subsidiary of ComEd.

PECO s commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

				Expiration within			
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) [(a)]	$ 22	$ 22	$	$	$	$	$
Surety bonds [(b)]	3	3					
Performance guarantees [(c)]	178						178
Total commercial commitments	$ 203	$ 25	$	$	$	$	$ 178

(a) Letters of credit (non-debt) PECO maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantees Reflects full and unconditional guarantee of Trust Preferred Securities of PECO Trust III and IV, which are 100% owned finance subsidiaries of PECO.

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BGE s commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) [(a)]	$ 1	$ 1	$	$	$	$	$
Surety bonds [(b)]	9	9					
Performance guarantees [(c)]	250						250
Total commercial commitments	$ 260	$ 10	$	$	$	$	$ 250

(a) Letters of credit (non-debt) BGE maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bond Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantee Reflects full and unconditional guarantee of Trust Preferred Securities of BGE Capital Trust which is an unconsolidated VIE of BGE.

Construction Commitments

Generation has committed to the construction of the Antelope Valley solar PV facility in Los Angeles County, California. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013 and an expectation of full commercial operation in the first half of 2014. Generation s estimated remaining commitment for the project is $110 million.

On July 3, 2013, Generation executed a Turbine Supply Agreement to expand its Beebe wind project in Michigan. The estimated remaining commitment under the contract is $50 million and achievement of commercial operations is expected in 2014.

On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland generation site with 120 MW of new natural gas-fired generation to satisfy certain merger commitments. The estimated remaining commitment under the contract is $80 million and achievement of commercial operation is expected in 2015. See 4 Merger and Acquisitions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the merger.

On December 27, 2013, Generated executed a Turbine Supply Agreement for construction of the 32.5MW Fourmile Wind project in western Maryland. The estimated remaining commitment under the contract is $26 million and achievement of commercial operations is expected in 2014. See 4 Merger and Acquisitions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the merger.

Refer to Note 3 Regulatory Matters for information on investment programs associated with regulatory mandates, such as ComEd s Infrastructure Investment Plan under EIMA, PECO s Smart Meter Procurement and Installation Plan, and BGE s comprehensive smart grid initiative.

Constellation Merger Commitments

Exelon s commercial and construction commitments shown above do not include the merger commitments made to the State of Maryland in conjunction with the Constellation merger. See Note 4 Merger and Acquisitions for additional information on the mergers commitments.

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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, 2013 were:

	Exelon	Generation	ComEd [b]	PECO [b]	BGE [b][c]
2014	$ 103	$ 49	$ 13	$ 13	$ 12
2015	91	50	11	3	11
2016	89	49	11	3	9
2017	82	48	7	3	8
2018	63	40	2	3	7
Remaining years	398	336	3		14
Total minimum future lease payments	$ 826[a]	$ 572[a]	$ 47	$ 25	$ 61

(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, ComEd, PECO and BGE have excluded these payments from the remaining years, as such amounts would not be meaningful. ComEd s, PECO s, and BGE s annual obligation for these arrangements, included in each of the years 2014 2018, was $1 million, $3 million, and $1 million respectively.
(c) Includes all future lease payments on a 99 year real estate lease that expires in 2105.

The following table presents the Registrants rental expense under operating leases for the years ended December 31, 2013, 2012 and 2011:

For the Year Ended December 31,	Exelon	Generation [a]	ComEd	PECO	BGE
2013	$ 806	$ 744	$ 15	$ 21	$ 11
2012	930	872	18	27	12
2011	711	659	18	28	15

(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 $694 million, $801 million and $630 million during 2013, 2012 and 2011, respectively.

For information regarding capital lease obligations, see Note 13 Debt and Credit Agreements.

Indemnifications Related to Sale of Sithe (Exelon and Generation)

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).

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, 2013. Generation believes that it is remote that it will be required to make any additional payments under the guarantee, and currently has no recorded liabilities associated with this guarantee. Generation expects that the exposure covered by this guarantee will expire in 2014. The guarantee is included above in the Commercial Commitments table under performance guarantees.

Combined Notes to Consolidated Financial Statements (Continued)

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

Indemnifications Related to Sale of TEG and TEP (Exelon and Generation)

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 was required to perform in the event that TII did not pay any obligation covered by the guarantee that was not otherwise subject to a dispute resolution process. Portions of the exposures covered by this guarantee expired in 2008, and the remaining guarantee expired in the third quarter of 2013. Generation was not required to make payments under the guarantee, and therefore, has no further obligation related to this guarantee as of December 31, 2013.

Environmental Matters

General. The Registrants operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property currently or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

ComEd, PECO and BGE have identified sites where former MGP activities have or may have resulted in actual site contamination. For many of these sites, ComEd, PECO or BGE is one of several PRPs that may be responsible for ultimate remediation of each location.

ComEd has identified 42 sites, 16 of which have been approved for cleanup by the Illinois EPA or the U.S. EPA and 26 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2016.

PECO has identified 26 sites, 16 of which have been approved for cleanup by the PA DEP and 10 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2020.

BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor s acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. One gas purification site is in the initial stages of investigation at the direction of the MDE.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. BGE is authorized to and is currently recovering environmental costs for the remediation of former MGP facility sites from customers; however, while BGE does not have a rider for

MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. ComEd, PECO and BGE have recorded regulatory assets for the recovery of these

Combined Notes to Consolidated Financial Statements (Continued)

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costs. During the third quarter of 2013, ComEd and PECO 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 less than $1 million and $6 million, respectively. BGE assessed its currently and formerly owned gas manufacturing and purification sites quarterly in 2013 and determined that a loss was not probable at ten of its sites as of December 31, 2013. As discussed above, the remediation costs at two of BGE s MGP sites are not considered material. Furthermore, an estimate of a range of possible loss, if any, related to BGE s gas purification site under investigation cannot be determined as of December 31, 2013 given that the site is in the early stages of investigation and the extent of contamination is currently unknown. See Note 3 Regulatory Matters for additional information regarding the associated regulatory assets.

The historical nature of the MGP sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial action. Management determines its best estimate of remediation costs based on probabilistic modeling and deterministic estimates using all available information at the time of each study and the remediation standards currently required by the U.S. EPA. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

As of December 31, 2013 and 2012, the Registrants have accrued the following undiscounted amounts for environmental liabilities in other current liabilities and other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

December 31, 2013	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 338	$ 273
Generation	56	
ComEd	234	229
PECO	47	44
BGE	1	

December 31, 2012	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 351	$ 298
Generation	42	
ComEd	261	254
PECO	47	44
BGE	1	

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

Water Quality

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

Combined Notes to Consolidated Financial Statements (Continued)

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Generation s and CENG 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 by changes to the existing regulations. For Generation, those facilities are Clinton, Dresden, Eddystone, Fairless Hills, Gould Street, Handley, Mountain Creek, Mystic 7, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. For CENG, those facilities are Calvert Cliffs, Nine Mile Point Unit 1 and R.E. Ginna.

On March 28, 2011, the U.S. 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 proposed rule also imposes limits on impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or another 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.

In June 2012, the U.S. EPA published two Notices of Data Availability (NODA) seeking public comment on alternate compliance technologies for impingement and the use of a public opinion survey to calculate the so-called non-use benefits of the rule. Exelon filed comments for each NODA, supporting the additional flexibility afforded by the impingement NODA, and opposing the NODA relating to calculation of non-use benefits due to its inaccurate and unreliable methodologies that would artificially inflate the benefits of proposed technologies that would otherwise not be cost-effective. On June 27, 2013, the U.S. EPA agreed to amend the court approved Settlement Agreement to extend the deadline to issue a final rule until November 4, 2013 and on October 30, 2013 the U.S. EPA invoked the *force majeure* provision of the Settlement Agreement to extend the final rule deadline until January 14, 2014 due to the early October 2013 federal government shutdown. The U.S. EPA and the plaintiffs have again agreed to extend the date for issuance of the final rule until April 17, 2014. Until the rule is finalized, the state permitting agencies will continue to apply their best professional judgment to address impingement and entrainment.

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.

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

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, as well as CENG s, 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 and CENG.

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 and CENG s generating facilities and its future results of operations, cash flows and financial position.

Groundwater Contamination. In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third-party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a $1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. Prior to the Merger, Constellation recorded in its Consolidated Balance Sheets total liabilities of approximately $30 million to comply with the consent decree with an additional $3 million recognized through purchase accounting. During third quarter of 2013, Generation increased its reserve by $2 million based on an update of future estimated remediation costs. The remaining liability as of December 31, 2013, is approximately $14 million. In addition, a private party asserted claims relating to groundwater contamination. Generation has reached an agreement in principle to resolve these claims. The amount of the settlement is not material to the financial condition of Generation.

Alleged Conemaugh Clean Streams Act Violation. The PA DEP has alleged that GenOn Northeast Management Company (GenOn), the operator of Conemaugh Generating Station, violated the Pennsylvania Clean Streams Law. GenOn reached agreement with PA DEP on a proposed Consent Decree that was approved by the Commonwealth Court of Pennsylvania on December 4, 2012. Under the Consent Decree, GenOn is obligated to pay a civil penalty of $0.5 million, of which Generation s responsibility was approximately $0.2 million. Generation made the final payment in January 2014 and is complying with the Consent Decree.

Air Quality

Cross-State Air Pollution Rule (CSAPR). 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 7, 2011, the U.S. EPA published the final rule, known as the CSAPR. The CSAPR requires 28 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.

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. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA

has exceeded its authority in certain material aspects of the CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. The Court s order was appealed to the U.S. Supreme Court, where oral argument was held on December 10, 2013. A decision is expected sometime during 2014.

Under the CSAPR, generation units were to receive allowances based on historic heat input and intrastate, and limited interstate, trading of allowances was permitted. The CSAPR restricted entirely the use of pre-2012 allowances. Existing SO_2 allowances under the ARP would remain available for use under ARP. As of December 31, 2013, Generation had \$56 million of emission allowances carried at the lower of weighted average cost or market.

EPA Mercury and Air Toxics Standards (MATS). The MATS rule became final on April 16, 2012. The MATS rule reduces emissions of toxic air pollutants, and finalized the new source performance standards for fossil fuel-fired electric utility steam generating units (EGUs). The MATS rule requires coal-fired EGUs 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 require 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, April 16, 2015, with specific guidelines for an additional one or two years in limited cases. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon was granted permission by the Court to intervene in support of the rule. A decision by the Court is expected sometime during 2014. The outcome of the appeal, and its impact on power plant operators investment and retirement decisions, is uncertain.

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.

In addition, as of December 31, 2013, Exelon had a \$698 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, after the impairment recorded in the second quarter of 2013, final applications of the CSAPR and MATS 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.

National Ambient Air Quality Standards (NAAQS). The U.S. EPA previously announced that it would complete a review of all NAAQS by 2014. Oral argument in the litigation (*State of Miss. v. EPA*) of the final 2008 ozone standard occurred in the D.C. Circuit Court in November 2012 and a final Court decision was issued on July 23, 2013 with the 2008 primary ozone standard upheld, but the secondary standard remanded to EPA for reconsideration. Concurrent with litigation of the 2008 ozone standard, the U.S. EPA continues its regular, periodic review of the ozone NAAQS and is expected to propose revisions in the fall of 2014, with preliminary indications that the U.S. EPA will likely propose a tightened standard. It is unclear at this point in time whether the U.S. EPA will be able to respond to the Court remand of the secondary 2008 ozone standard on a timeframe that would be any quicker than

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that of the U.S. EPA s current, periodic review schedule. In December 2012, the U.S. EPA issued its final revisions to the Agency s particulate matter (PM) NAAQS. In its final rule, the U.S. EPA lowered the annual PM2.5 standard, but declined to issue a new secondary NAAQS to improve urban visibility. The U.S. EPA indicated in its final rule that by 2020 it expects most areas of the country will be in attainment of the new PM2.5 NAAQS based on currently expected regulations, such as the MATS regulation. It is unclear if the vacatur of the CSAPR, one of the regulations that the U.S. EPA is relying on to assist with future PM reduction, would alter the U.S. EPA s view since either CAIR or a finalized CSAPR regulation would be in effect leading up to 2020. In March 2013, a number of industry coalitions filed a joint lawsuit challenging the new PM2.5 standard. Also during early 2013, the D.C. Circuit remanded several rules for implementation of earlier PM2.5 NAAQS to the U.S. EPA for revision of certain aspects of the rules, with a requirement that the U.S. EPA re-promulgate regulations in conformance with the correct subparts of the Clean Air Act.

In addition to these NAAQS, the U.S. EPA also finalized nonattainment designations for certain areas in the United States for the 2010 one-hour SO_2 standard on August 5, 2013, and indicated that additional nonattainment areas will be designated in a future rulemaking. U.S. EPA will require states to submit state implementation plans (SIPs) for nonattainment areas by April 2015. With regard to Texas and Maryland, no nonattainment areas were identified in U.S. EPA s final designation rule. With regard to Illinois and Pennsylvania, several counties, or portions of counties, in each state were identified as nonattainment. The U.S. EPA will follow the approach outlined in a February 2013 U.S. EPA strategy document that establishes a process and timeline for the Agency to address additional designations in states counties under a future rulemaking. Nonattainment county compliance with the one-hour SO_2 standard is required by October 2018. While significant SO_2 reductions will occur as a result of MATS compliance in 2015, Exelon is unable to predict the requirements of pending states SIPs to further reduce SO_2 emissions in support of attainment of the one hour SO_2 standard.

Notices and Finding of Violations and Midwest Generation Bankruptcy. In December 1999, ComEd sold several generating stations to Midwest Generation, LLC (Midwest Generation), a subsidiary of Edison Mission Energy (EME). Under the terms of the sale agreement, Midwest Generation and EME assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance by the stations with environmental laws before their purchase by Midwest Generation. Midwest Generation and EME additionally agreed to indemnify and hold ComEd and its affiliates harmless from claims, fines, penalties, liabilities and expenses arising from third-party claims against ComEd resulting from or arising out of the environmental liabilities assumed by Midwest Generation and EME under the terms of the agreement governing the sale. In connection with Exelon s 2001 corporate restructuring, Generation assumed ComEd s rights and obligations with respect to its former generation business, including its rights and obligations under the sale agreement with Midwest Generation and EME.

On December 17, 2012 (Petition Date), EME and certain of its subsidiaries, including Midwest Generation, filed for protection under Chapter 11 of the U.S. Bankruptcy Code.

In 2012, the Bankruptcy Court approved the rejection of a coal rail car lease under which Midwest Generation had agreed to reimburse ComEd for all obligations. The rejection left Generation as the party responsible to make remaining payments under the lease. In January 2013, Generation made the final $10 million payment due under the lease agreement which had been accrued at December 31, 2012.

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

During the second quarter of 2013, Exelon filed proofs of claim of $21 million with the Bankruptcy Court for amounts owed by EME and Midwest Generation for the coal rail car lease, ComEd utility payments and certain legal costs. Further, Exelon filed an environmental claim with an unspecified amount that listed the indemnifications that were in place pre-Petition Date and other factors associated with the remediation. As of December 31, 2013, Exelon has not recorded a receivable for the filed proofs of claim because recovery of any amount cannot be assured at this point in the bankruptcy. Exelon will not record claim recoveries unless and until they are realized.

Certain environmental laws and regulations subject current and prior owners of properties or generators of hazardous substances at such properties to liability for remediation costs of environmental contamination. As a prior owner of the generating stations, ComEd (and Generation, through its agreement in Exelon s 2001 corporate restructuring to assume ComEd s rights and obligations associated with its former generation business) could face liability (along with any other potentially responsible parties) for environmental conditions at the stations requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors, including the impact of Midwest Generation s bankruptcy. On January 17, 2014, Midwest Generation filed a plan supplement to its bankruptcy filing that included a request to reject the sale agreement, including the environmental indemnity. ComEd and Generation have reviewed available public information as to potential environmental exposures regarding the Midwest Generation station sites. Midwest Generation publicly disclosed in its quarter ending September 30, 2013 Form 10-Q that (i) it has accrued a probable amount of approximately $8 million for estimated environmental investigation and remediation costs under CERCLA, or similar laws, for the investigation and remediation of contaminated property at four Midwest Generation plant sites, (ii) it has identified stations for which a reasonable estimate for investigation and/ or remediation cannot be made and (iii) it and the Illinois EPA entered into Compliance Commitment Agreements outlining specified environmental remediation measures and groundwater monitoring activities to be undertaken at its Crawford, Powerton, Joliet, Will County and Waukegan generating stations. At this time, however, ComEd and Generation do not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted. For these reasons, ComEd and Generation are unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to the generating stations and as a result no liability has been recorded as of December 31, 2013. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

Under a supplemental agreement reached in 2003, Midwest Generation agreed to reimburse ComEd and Generation for 50% of the specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. In addition to the sale agreement, Midwest Generation also requested to reject this supplemental agreement in the January 17, 2014 plan supplement to its bankruptcy filing. Exelon and Generation had previously expected Midwest Generation or its successor would remain responsible for asbestos personal injury claims filed post-Petition Date, and as a result had not recorded a liability for such amounts. Exelon and Generation now believe that the rejection of the 1999 sale and supplemental agreements is probable, and as a result, Generation has increased its reserve for asbestos-related bodily injury claims at December 31, 2013 by $25 million. The increase in the reserve was estimated using actuarial assumptions and analyses available to Generation. Generation s exposure could differ to the extent new information is received or made available. Midwest Generation publicly disclosed in its quarter ending September 30, 2013 Form 10-Q that they had $53 million recorded related to asbestos bodily injury claims under the contractual indemnity with ComEd. If the agreements are rejected, Exelon and

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Generation may be entitled to damages associated with the agreement terminations. These amounts are considered to be contingent gains and would not be recognized until realized.

On October 18, 2013, NRG Energy entered into an agreement to buy EME s portfolio of generation subject to regulatory approvals. Exelon continues to monitor all aspects of the bankruptcy; the proposed purchase by NRG has not impacted any accounting conclusions as of December 31, 2013.

In May 2010, the United States and State of Illinois initiated a lawsuit against Midwest Generation, ComEd and EME alleging Clean Air Act violations relating to the modification and/or operation of six (coal) electric generation plants in Northern Illinois, which ComEd sold to Midwest Generation/EME in 1999. The government parties sought injunctive relief and civil penalties against all defendants, although not all of the claims specifically pertained to ComEd. On March 16, 2011, the District Court granted ComEd s motion to dismiss the May 2010 complaint in its entirety as it relates to ComEd. On January 3, 2012, upon leave of the District Court, the government parties appealed the dismissal of ComEd to the U.S. Circuit Court of Appeals for the Seventh Circuit. On July 8, 2013, the Circuit Court affirmed the District Court s dismissal of the complaint against ComEd. On September 19, 2013, the Circuit Court denied the petition for a rehearing filed by the governmental parties. The government parties did not seek United States Supreme Court review of the Seventh Circuit s decision. The deadline for seeking such review was in December 2013. In light of the Circuit Court decision resolving this matter in favor of ComEd, no reserve has been established.

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 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 complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. In June 2012, the U.S. EPA requested that the PRPs perform additional analysis and groundwater sampling as part of the supplemental feasibility study that could take up to one year to complete, and subsequently requested additional analysis sampling and modeling to be conducted into 2014. In light of these additional requests, it is unknown when the U.S EPA will propose a remedy for public comment. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. A complete 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 a complete 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

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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 1969 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 $90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2014 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.

On February 28, 2012, and April 12, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 15 and 14 defendants, respectively, including Exelon, Generation and ComEd (the Exelon defendants) and Cotter. The suits allege that individuals living in the North St. Louis area developed some form of cancer due to the defendants negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. On May 30, 2012, the plaintiffs filed voluntary motions to dismiss the Exelon defendants from both lawsuits which were subsequently granted. Since May 30, 2012, several related lawsuits have been filed in the same court on behalf of various plaintiffs against Cotter and other defendants, but not Exelon. The allegations in these related lawsuits mirror the initially filed lawsuits. In the event of a finding of liability, it is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. On March 27, 2013, the U.S. District Court dismissed all state common law actions brought under the initial two lawsuits; and also found that the plaintiffs had not properly brought the actions under the Price-Anderson Act. On July 8, 2013, the plaintiffs filed amended complaints under the Price-Anderson Act. Cotter moved to dismiss the amended complaints and has motions currently pending before the court. At this stage of the litigation, Exelon cannot estimate a range of loss, if any.

68th Street Dump. In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The PRPs submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the U.S. EPA are still subject to U.S. EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of $50 million to $64 million. On September 30, 2013, U.S. EPA issued the Record of Decision identifying its preferred remedial alternative for the site. The estimated cost for the alternative chosen by U.S. EPA is consistent with the PRPs estimated range of costs noted above. Based on Exelon s preliminary review, it appears probable that Exelon has liability and has established an appropriate accrual for its share of the estimated clean-up costs. BGE is indemnified by a wholly owned subsidiary of Generation for most of the costs related to this settlement and clean-up of the site.

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

Rossville Ash Site. The Rossville Ash Site is a 32-acre property located in Rosedale, Baltimore County, Maryland, which was used for the placement of fly ash from 1983-2007. The property is owned by Constellation Power Source Generation, LLC(CPSG). In 2008, CPSG investigated and remediated the property by entering it into the Maryland Voluntary Cleanup Program (VCP) to address any historic environmental concerns and ready the site for appropriate future redevelopment. The site was accepted into the program in 2010 and is currently going through the process to remediate the site and receive closure from MDE. Exelon currently estimates the cost to close the site to be approximately $6 million, which has been fully reserved as of December 31, 2013.

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, Maryland. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the U.S. EPA is seeking recovery from the PRPs of $1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRP s signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which requires the PRP s to conduct a Remedial Investigation and Feasibility Study at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE s reasonably possible loss, if any, cannot be determined.

Climate Change Regulation. Exelon is subject to climate change regulation or legislation at the 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 (the Tailoring Rule) 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. On July 2, 2012 the U.S. EPA declined to lower GHG permit thresholds in its final Step 3 Tailoring Rule update. The U.S. EPA will review permit thresholds again in a 2015 rulemaking process. On June 26, 2012, the United States Court of Appeals for the District of Columbia, in a *per curium* decision, dismissed industry and state petitions challenging the U.S. EPA s Tailpipe Rule for cars and light duty trucks, the endangerment finding for GHG s from stationary sources, and the Tailoring Rule. On October 15, 2013 the U.S. Supreme Court granted industry petitions to review one aspect of the PSD permitting regulations. Under the PSD 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. Generation could be significantly affected by the regulations if it were to build new plants or modify existing plants.

On June 25, 2013, President Obama announced The President s Climate Action Plan, a summary of executive branch actions intended to: reduce carbon emissions; prepare the United States

Combined Notes to Consolidated Financial Statements (Continued)

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

for the impacts of climate change; and lead international efforts to combat global climate change and prepare for its impacts. Concurrent with the announcement of the Administration s plan, the President also issued a Memorandum for the Administrator of the Environmental Protection Agency that focused on power generation sector carbon reductions under the Section 111 New Source Performance Standards (NSPS) section of the federal Clean Air Act. The memorandum directs the U.S. EPA Administrator to issue two sets of proposed rulemakings with regard to power plant carbon emissions under Section 111 of the Clean Air Act.

The first rulemaking, under Section 111(b) of the Clean Air Act is to focus on establishing carbon regulations for new fossil-fuel power plants. This rulemaking was proposed on September 20, 2013 and is to be finalized in a timely fashion. In the proposed rule U.S.EPA sets separate standards for fossil-fuel fired utility boilers and natural gas fired stationary combustion turbines.

The second rulemaking, under Section 111(d) of the Clean Air Act is to focus on modified, reconstructed and existing fossil power plants. The rulemaking is to be proposed no later than June 1, 2014, be finalized no later than June 1, 2015, and require that states submit to U.S. EPA their implementation plans no later than June 30, 2016. In developing this rulemaking, U.S. EPA is directed to consider a number of factors, including options to reduce costs, options to ensure the continued use of a range of energy sources and technologies, options that are consistent with reliable and affordable power, and options that allow for the use of market-based instruments, performance standards and other regulatory flexibilities.

To the extent that the final Section 111(d) rule results in emission reductions from fossil fuel fired plants, and thereby imposes some form of direct or indirect price of carbon in competitive electricity markets, Exelon s overall low-carbon generation portfolio results could benefit.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims (Exelon, Generation, PECO and BGE).

Exelon and Generation. Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The reserve is recorded on an undiscounted basis and excludes the estimated legal costs associated with handling these matters, which could be material.

At December 31, 2013 and 2012, Generation had reserved approximately $90 million and $63 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2013, approximately $19 million of this amount related to 224 open claims presented to Generation, while the remaining $71 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.

On November 22, 2013, the Supreme Court of Pennsylvania held that the Pennsylvania Workers Compensation Act does not apply to an employee s disability or death resulting from occupational disease, such as diseases related to asbestos exposure, which manifests more than 300 weeks after the employee s last employment-based exposure, and that therefore the exclusivity provision of the Act does not apply to preclude such employee from suing his or her employer in court. The Supreme

Combined Notes to Consolidated Financial Statements (Continued)

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

Court s ruling reverses previous rulings by the Pennsylvania Superior Court precluding current and former employees from suing their employers in court, despite the fact that the same employee was not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee s last employment-based exposure to asbestos. Currently, Exelon, Generation and PECO are unable to predict whether and to what extent they may experience additional claims in the future as a result of this ruling; as such no increase to the asbestos-related bodily injury liability has been recorded as of December 31, 2013. Increased claims activity resulting from this ruling could have a material adverse impact on Exelon, Generation s and PECO s future results of operations and cash flows.

BGE. Since 1993, BGE and certain Constellation (now Generation) subsidiaries have been involved in several actions concerning asbestos. The actions are based upon the theory of premises liability, alleging that BGE and Generation knew of and exposed individuals to an asbestos hazard. In addition to BGE and Generation, numerous other parties are defendants in these cases.

Approximately 486 individuals who were never employees of BGE or certain Constellation subsidiaries have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and certain Constellation subsidiaries in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or certain Constellation subsidiaries and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation s financial results.

Discovery begins in these cases after they are placed on the trial docket. At present, only two of the pending cases are set for trial. Given the limited discovery in these cases, BGE and Generation do not know the specific facts that are necessary to provide an estimate of the reasonably possible loss relating to these claims; as such, no accrual has been made and a range of loss is not estimable. The specific facts not known include:

- the identity of the facilities at which the plaintiffs allegedly worked as contractors;
- the names of the plaintiffs employers;
- the dates on which and the places where the exposure allegedly occurred; and
- the facts and circumstances relating to the alleged exposure.

Insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions.

Federal Energy Regulatory Commission Investigation (Exelon and Generation).

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 ISO-NY from September 2007 through December 2008. Prior to the merger, Constellation announced on March 9, 2012, that it had resolved the FERC investigation. Under the settlement, Constellation agreed to pay, and has paid, a $135 million civil penalty and $110 million in disgorgement.

During the year ended December 31, 2012, Generation recorded expense of $195 million in operating and maintenance expense with the remaining $50 million recorded as a Constellation pre-acquisition contingency. See Note 4 Merger and Acquisitions for additional information on the merger.

Combined Notes to Consolidated Financial Statements (Continued)

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

Continuous Power Interruption (ComEd)

Section 16-125 of the Illinois Public Utilities Act 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) more than 30,000 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.

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable for damage compensation to customers in connection with the July 11, 2011 storm system that produced multiple power interruptions that in the aggregate affected more than 900,000 customers in ComEd s service territory, as well as for five other storm systems that affected ComEd s customers during June and July 2011 (Summer 2011 Storm Docket). In addition, on September 29, 2011, ComEd sought from the ICC a determination that it was not liable for damage compensation related to the February 1, 2011 blizzard (February 2011 Blizzard Docket).

On June 5, 2013, the ICC approved a complete waiver of liability for five of the six summer storms and the February 2011 blizzard. However, the ICC held that for the July 11, 2011 storm, 34,559 interruptions were preventable and therefore no waiver should apply. As required by the ICC s Order, ComEd notified relevant customers that they may be entitled to seek reimbursement of incurred costs in accordance with a claims procedure established under ICC rules and regulations. In addition, the ICC found that ComEd did not systematically fail in its duty to provide adequate, reliable and safe service. As a result, the ICC rejected the Illinois Attorney General s request for the ICC to open an investigation into ComEd s infrastructure and storm hardening investments.

Following the ICC s June 26, 2013 denial of ComEd s request for rehearing, on June 27, 2013 ComEd filed an appeal of both the summer and winter storm dockets with the Illinois Appellate Court regarding the ICC s interpretation of Section 16-125 of the Illinois Public Utilities Act. ComEd cannot predict the outcome of appeals.

As a result of the ICC s June 5, 2013 ruling, ComEd established a liability, which was not material, for potential reimbursements for actual damages incurred by the 34,559 customers covered by the ICC s June 5, 2013 Order. The liability recorded represents the low end of a range of potential losses given that no amount within the range represents a better estimate. ComEd s ultimate liability will be based on actual claims eligible for reimbursement as well as the outcome of the appeal. Although reimbursements for actual damages will differ from the estimated accrual recorded, at this time ComEd does not expect the difference to be material to ComEd s results of operations or cash flows.

ComEd has not recorded an accrual for reimbursement of local governmental emergency and contingency expenses as a range of loss, if any, cannot be reasonably estimated at this time, but may be material to ComEd s results of operations and cash flows.

Telephone Consumer Protection Act Lawsuit (ComEd)

On November 19, 2013, a class action complaint was filed in Cook County on behalf of a single individual and a presumptive class that would include all customers in ComEd s service territory who

Combined Notes to Consolidated Financial Statements (Continued)

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

were enrolled by the Company in ComEd s Outage Alert text message program. The complaint alleges that ComEd violated the Telephone Consumer Protection Act (TCPA) by sending approximately 1.2 million text messages to customers without first obtaining their consent to receive such messages. The complaint seeks certification of a class along with statutory damages, attorneys fees, and an order prohibiting ComEd from sending additional text messages. Such statutory damages could range from $500 to $1,500 per text. However, ComEd is preparing a motion to dismiss this class action complaint and will vigorously contest the allegations of this suit. The ultimate outcome of this proceeding is uncertain, and an amount, if any, which might be asserted, cannot be reasonably estimated at this time, but may be material to ComEd s results of operations and cash flows. As a result, ComEd has not established a reserve for this complaint as of December 31, 2013.

Securities Class Action (Exelon)

Three federal securities class action lawsuits were filed in the United States District Courts for the Southern District of New York and the District of Maryland between September 2008 and November 2008 against Constellation. The cases were filed on behalf of a proposed class of persons who acquired publicly traded securities, including the Series A Junior Subordinated Debentures (Debentures), of Constellation between January 30, 2008 and September 16, 2008, and who acquired Debentures in an offering completed in June 2008. The securities class actions generally allege that Constellation, a number of its former officers or directors, and the underwriters violated the securities laws by issuing a false and misleading registration statement and prospectus in connection with Constellation s June 27, 2008 offering of the Debentures. The securities class actions also allege that Constellation issued false or misleading statements or was aware of material undisclosed information which contradicted public statements, including in connection with its announcements of financial results for 2007, the fourth quarter of 2007, the first quarter of 2008 and the second quarter of 2008 and the filing of its first quarter 2008 Form 10-Q. The securities class actions sought, among other things, certification of the cases as class actions, compensatory damages, reasonable costs and expenses, including counsel fees, and rescission damages.

The Southern District of New York granted the defendants motion to transfer the two securities class actions filed in Maryland to the District of Maryland, and the actions have since been transferred for coordination with the securities class action filed there. On May 9, 2013, the federal court in Maryland preliminarily approved the settlement of Constellation s 2008 Securities Class Action for a payment of $4 million, which will be paid by Constellation s insurer. Notice of the settlement was provided to class members in June 2013 and the court approved the final settlement on November 4, 2013. This settlement will resolve all of Constellation s litigation arising from the 2008 Securities Class Action lawsuit.

Fund Transfer Restrictions (Exelon, Generation, ComEd, PECO and BGE)

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;

Combined Notes to Consolidated Financial Statements (Continued)

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

(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. On May 1, 2013, PECO redeemed all outstanding preferred securities. As a result, the above ratio calculation is no longer applicable. 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.

BGE pays dividends on its common stock after its board of directors declares them. However, BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE s equity ratio would be below 48% as calculated pursuant to the MDPSC s ratemaking precedents or (b) BGE s senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE s preference stock have not been paid.

Baltimore City Franchise Taxes (BGE)

The City of Baltimore claims that BGE has maintained electric facilities in the City s public right-of-ways for over one hundred years without the proper franchise rights from the City. BGE is currently reviewing the merits of this claim. BGE has not recorded an accrual for payment of franchise fees for past periods as a range of loss, if any, cannot be reasonably estimated at this time. Franchise fees assessed in future periods may be material to BGE s results of operations and cash flows.

Combined Notes to Consolidated Financial Statements (Continued)

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

General (Exelon, Generation, ComEd, PECO and BGE).

The Registrants are 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. The Registrants 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.

Income Taxes

See Note 14 Income Taxes for information regarding the Registrants income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

23. Supplemental Financial Information (Exelon, Generation, ComEd, PECO and BGE)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants Consolidated Statements of Operations for the years ended December 31, 2013, 2012 and 2011.

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [(a)]	$ 449	$ 79	$ 241	$ 129	$ 82
Property	302	205	24	14	112
Payroll	159	89	27	13	15
Other	185	16	7	2	4
Total taxes other than income	$ 1,095	$ 389	$ 299	$ 158	$ 213

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [(a)]	$ 463	$ 82	$ 239	$ 141	$ 75
Property	227	189	22	13	111

Payroll	131	78	26	12	18
Other	198	20	8	(4)	4
Total taxes other than income	$ 1,019	$ 369	$ 295	$ 162	$ 208

Combined Notes to Consolidated Financial Statements (Continued)

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

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [(a)]	$ 443	$ 27	$ 243	$ 173	$ 79
Property	177	146	22	9	107
Payroll	123	71	25	13	17
Other	42	20	6	10	4
Total taxes other than income	$ 785	$ 264	$ 296	$ 205	$ 207

(a) Generation s utility tax represents gross receipts tax related to its retail operations and ComEd s, PECO s and BGE 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 the Registrants Consolidated Statements of Operations and Comprehensive Income.

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [(a)]					
Regulatory agreement units	$ 256	$ 256	$	$	$
Non-regulatory agreement units	77	77			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	406	406			
Non-regulatory agreement units	146	146			
Net unrealized gains on pledged assets					
Zion Station decommissioning	7	7			
Regulatory offset to decommissioning trust fund-related activities [(b)]	(546)	(546)			
Total decommissioning-related activities	346	346			
Investment income	8	(1)		(1)	9[(c)]
Long-term lease income	28				
Interest income related to uncertain income tax positions	24	4			
AFUDC Equity	22		11	4	7
Other	45	19	15	3	1
Other, net	$ 473	$ 368	$ 26	$ 6	$ 17

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [(a)]					
Regulatory agreement units	$ 189	$ 189	$	$	$
Non-regulatory agreement Units	102	102			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	386	386			
Non-regulatory agreement units	105	105			
Net unrealized gains on pledged assets					
Zion Station decommissioning	73	73			

Regulatory offset to decommissioning trust fund-related activities [b]	(530)	(530)
Total decommissioning-related activities	325	325

Combined Notes to Consolidated Financial Statements (Continued)

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

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Investment income	20	3	1	2	11[c]
Long-term lease income	29				
Interest income related to uncertain income tax positions	15	2	20		
AFUDC Equity	17		6	4	10
Credit facility termination fees	(85)	(85)			
Other	25	(6)	12	2	2
Other, net	$ 346	$ 239	$ 39	$ 8	$ 23

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a]					
Regulatory agreement units	$ 177	$ 177	$	$	$
Non-regulatory agreement units	45	45			
Net unrealized losses on decommissioning trust funds					
Regulatory agreement units	(74)	(74)			
Non-regulatory agreement units	(4)	(4)			
Net unrealized gains on pledged assets					
Zion Station decommissioning	48	48			
Regulatory offset to decommissioning trust fund-related activities [b]	(130)	(130)			
Total decommissioning-related activities	62	62			
Investment income	10	1	1	3	13[c]
Long-term lease income	28				
Interest income related to uncertain income tax positions	53	31	14	1	
AFUDC Equity	17		8	9	15
Bargain purchase gain related to Wolf Hollow acquisition	36	36			
Other	(3)	(8)	6	1	(2)
Other, net	$ 203	$ 122	$ 29	$ 14	$ 26

(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 15 Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(c) Relates to the cash return on BGE s rate stabilization deferral. See Note 3 Regulatory Matters for additional information regarding the rate stabilization deferral.

Combined Notes to Consolidated Financial Statements (Continued)

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

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011.

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$ 1,893	$ 813	$ 545	$ 219	$ 264
Regulatory assets	212		119	9	84
Amortization of intangible assets, net	48	43	5		
Amortization of energy contract assets and liabilities [(a)]	430	507			
Nuclear fuel [(a)]	921	921			
ARO accretion [(b)]	275	275			
Total depreciation, amortization, accretion and depletion	$ 3,779	$ 2,559	$ 669	$ 228	$ 348

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$ 1,712	$ 733	$ 525	$ 207	$ 245
Regulatory assets	129		80	10	53
Amortization of intangible assets, net	40	35	5		
Amortization of energy contract assets and liabilities [(a)]	1,110	1,110			
Nuclear fuel [(a)]	848	848			
ARO accretion [(b)]	240	240			
Total depreciation, amortization, accretion and depletion	$ 4,079	$ 2,966	$ 610	$ 217	$ 298

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization and accretion					
Property, plant and equipment	$ 1,284	$ 570	$ 502	$ 191	$ 224
Regulatory assets	63		52	11	50
Nuclear fuel [(a)]	755	755			
ARO accretion [(b)]	214	214			
Total depreciation, amortization and accretion	$ 2,316	$ 1,539	$ 554	$ 202	$ 274

(a) Included in revenues or fuel expense, or operating revenues on the Registrants Consolidated Statements of Operations and Comprehensive Income.
(b) Included in operating and maintenance expense on the Registrants Consolidated Statements of Operations and Comprehensive Income.

Combined Notes to Consolidated Financial Statements (Continued)

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

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 866	$ 291	$ 283	$ 95	$ 130
Income taxes (net of refunds)	112	(18)	33	70	42
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 825	$ 345	$ 308	$ 43	$ 56
Earnings from equity method investments	(10)	(10)			
Provision for uncollectible accounts	101	10	(15)	61	44
Provision for excess and obsolete inventory	9	9			
Stock-based compensation costs	120				
Other decommissioning-related activity [a]	(169)	(169)			
Energy-related options [b]	104	104			
Amortization of regulatory asset related to debt costs	12		9	3	
Amortization of rate stabilization deferral	66				66
Amortization of debt fair value adjustment	(34)	(34)			
Discrete impacts from EIMA [c]	(271)		(271)		
Amortization of debt costs	18	10	1	2	2
Impairment of investments in direct financing leases [e]	14				
Impairment charges [f]	149	149			
Other	(58)		(4)	(1)	(15)
Total other non-cash operating activities	$ 876	$ 414	$ 28	$ 108	$ 153
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 12	$	$ (35)	$ 9	$ 38
Other regulatory assets and liabilities	(64)		(43)	(16)	(71)
Other current assets	(165)	(151)	(2)	13	(8)
Other noncurrent assets and liabilities	322	15	268[g]	(12)	(23)
Total changes in other assets and liabilities	$ 105	$ (136)	$ 188	$ (6)	$ (64)

	Exelon	Generation	ComEd	PECO	BGE
Non-cash investing and financing activities:					
Change in ARC	$ (128)	$ (128)	$	$	$ 4
Change in capital expenditures not paid	(38)	(107)[h]	(8)	13	(48)
Consolidated VIE dividend to non-controlling interest	63	63			
Indemnification of like-kind exchange position [i]			176		

(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 15 Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.

(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 3 Regulatory Matters for more information.

(d) Relates to integration costs to achieve distribution synergies related to the merger transaction. See Note 3 Regulatory Matters for more information.

(e) Relates to an other than temporary decline in the estimated residual value of one of Exelon s direct financing leases. See Note 8 Impairment of Long-Lived Assets for more information.

(f) Relates to the cancellation of uprate projects and write down of certain wind projects at Generation. See Note 8 Impairment of Long-Lived Assets for more information.

Combined Notes to Consolidated Financial Statements (Continued)

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

(g) Relates primarily to interest payable related to like-kind exchange tax position. See Note 14 Income Taxes for discussion of the like-kind exchange tax position.
(h) Includes $55 million of changes in capital expenditures not paid between December 31, 2013 and 2012 related to Antelope Valley.
(i) See Note 14 Income Taxes for discussion of the like-kind exchange tax position.

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 761	$ 286	$ 288	$ 113	$ 136
Income taxes (net of refunds)	(171)	175	(42)	(64)	(112)
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 820	$ 341	$ 282	$ 50	$ 57
Loss in equity method investments	91	91			
Provision for uncollectible accounts	164	22	42	60	44
Provision for excess and obsolete inventory	6	6	1		
Stock-based compensation costs	94				
Other decommissioning-related activity [a]	(145)	(145)			
Energy-related options [b]	160	160			
Amortization of regulatory asset related to debt costs	18		13	3	2
Amortization of rate stabilization deferral	57				67
Amortization of debt fair value adjustment	(34)	(34)			
Merger-related commitments [d]	141	32			27
Severance costs	99	34			
Discrete impacts from EIMA [c]	(96)		(96)		
Amortization of debt costs	19	11	5	3	2
Other	(11)	19	5	9	(6)
Total other non-cash operating activities	$ 1,383	$ 537	$ 252	$ 125	$ 193
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 71	$	$ 28	$ 20	$ 26
Other regulatory assets and liabilities	(404)		(68)	18	(112)
Other current assets	213	(30)	(7)	(12)	(7)
Other noncurrent assets and liabilities	(248)	(98)	(95)	(10)	8
Total changes in other assets and liabilities	$ (368)	$ (128)	$ (142)	$ 16	$ (85)

	Exelon	Generation	ComEd	PECO	BGE
Non-cash investing and financing activities:					
Change in ARC	$ 781	$ 781	$ 2	$	$
Change in capital expenditures not paid	160	103[e]	15	26	(4)
Merger with Constellation, common stock issued	7,365	5,264			

(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 15 Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 3 Regulatory Matters for more information.

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Combined Notes to Consolidated Financial Statements (Continued)

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

(d) Relates to the integration costs to achieve distribution synergies related to the merger transaction. See Note 4 Mergers and Acquisitions for more information on merger-related commitments.
(e) Includes $127 million of changes in capital expenditures not paid between December 31, 2012 and 2011 related to Antelope Valley.

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 649	$ 158	$ 296	$ 128	$ 122
Income taxes (net of refunds)	(457)	347	(676)	(65)	(54)
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 542	$ 249	$ 213	$ 32	$ 51
Provision for uncollectible accounts	121		57	64	44
Stock-based compensation costs	67				
Other decommissioning-related activity [(a)]	16	16			