EXELON CORP
Form 10-K
February 13, 2015

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, 2014

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)**	23-2990190

10 South Dearborn Street

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
Corporate Units	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

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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. x

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, 2014 was as follows:

Exelon Corporation Common Stock, without par value	$31,319,710,373
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, 2015 was as follows:

Exelon Corporation Common Stock, without par value	859,833,343
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,950
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 2015 Annual Meeting of

Shareholders and the Commonwealth Edison Company 2015 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.
Antelope Valley, AVSR	Antelope Valley Solar Ranch One
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

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Other Terms and Abbreviations	
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
DC Circuit Court	United States Court of Appeals for the District of Columbia Circuit
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
EGR	ExGen Renewables I, LLC
EGS	Electric Generation Supplier
EGTP	ExGen Texas Power, LLC
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
GDP	Gross Domestic Product
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
Integrys	Integrys Energy Services, Inc.
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service

Other Terms and Abbreviations

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
LTIP	Long-Term Incentive Plan
MATS	U.S. EPA Mercury and Air Toxics Standard 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
NGS	Natural Gas Supplier
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 including the CENG units (Calvert Cliffs, Nine Mile Point, and R.E. Ginna),Clinton, Oyster Creek, Three Mile Island, Zion (a former ComEd unit), and portions of Peach Bottom (a former PECO unit)
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

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Other Terms and Abbreviations	
POR	Purchase of Receivables
PPA	Power Purchase Agreement
PPL	PPL Holtwood, LLC
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 including the former ComEd units (Braidwood, Byron, Dresden, LaSalle, Quad Cities) and the former PECO units (Limerick, Peach Bottom, Salem)
RES	Retail Electric Suppliers
RFP	Request for Proposal
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
SOA	Society of Actuaries
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
Upstream	Natural gas and oil exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

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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

This Report contains certain forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by a Registrants include those factors discussed herein, including those factors discussed 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 and (c) ITEM 8. Financial Statements and Supplementary Data: Note 22; and (d) other factors discussed in 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.

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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 the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities (Upstream). 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 electricity 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 electricity 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.

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BGE

BGE s energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity 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 natural 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 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on Exelon s operating segments.

Pending Merger with Pepco Holdings, Inc.

On April 29, 2014, Exelon and PHI signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. The merger is expected to be completed in the second or third quarter of 2015. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the pending 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. Constellation sells electricity and natural gas to both wholesale and retail customers. The retail sales include commercial, industrial and residential customers. 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. Generation s 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 challenging conditions emanating from competitive energy markets. Generation s customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities (Upstream).

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 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

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not limited to, third-party financings; review of mergers; dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility; affiliate transactions; intercompany financings and cash management arrangements; certain internal corporate reorganizations; and certain holding company acquisitions of public utility and holding company securities. 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.

Merger with Constellation Energy Group, Inc.

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. Since the merger transaction, Generation includes the former Constellation generation and customer supply operations. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the Constellation merger.

Constellation Energy Nuclear Group, Inc.

Generation 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 a total of five nuclear generating facilities on three sites, Calvert Cliffs, R.E. 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.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF s noncontrolling interest in CENG at fair value on Exelon s and Generation s Consolidated Balance Sheets. Refer to Note 5 Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for further information regarding the integration transaction.

Significant Acquisitions

Integrys Energy Services, Inc. On November 1, 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. (Integrys) for a purchase price of $332 million, including net working capital. The generation and solar asset businesses of Integrys are excluded from the transaction. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the above acquisition.

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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 242-MW solar project under development in northern Los Angeles County, California, from First Solar, Inc. The facility became fully operational in 2014. 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. Total capitalized costs for the facility incurred as of December 31, 2014 were approximately $1.1 billion.

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 704 MWs.

Significant Dispositions

Asset Divestitures. As of December 31, 2014, Generation sold or entered into agreements to divest certain generating assets with total expected pre-tax proceeds of $1.8 billion (after-tax proceeds of approximately $1.4 billion). The proceeds are expected to be used primarily to finance a portion of the acquisition of PHI.

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 with Constellation Energy Group, Inc. for net proceeds of approximately $371 million, which resulted in a pre-tax impairment charge of $272 million.

See Note 4 Mergers, Acquisitions, and Dispositions and Note 8 Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for additional information.

Generating Resources

At December 31, 2014, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets [(a)(b)]	
Nuclear	19,316
Fossil [(c)]	9,515
Renewable [(d)]	3,434
Owned generation assets	32,265
Long-term power purchase contracts	9,574
Total generating resources	41,839

(a) See Fuel for sources of fuels used in electric generation.
(b) Net generation capacity is stated at proportionate ownership share. See ITEM 2. PROPERTIES Generation for additional information.
(c) Comprised primarily of natural gas generating assets. Excludes Quail Run, which was sold on January 21, 2015.
(d) Includes hydroelectric, wind, and solar generating assets.

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 35% 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 38% of capacity).

New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont (approximately 7% 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 11% of capacity).

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

See Note 24 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers and revenues net of purchased power and fuel expense for each of Generation s reportable segments.

Nuclear Facilities

Generation has ownership interests in fourteen nuclear generating stations currently in service, consisting of 24 units with an aggregate of 19,316 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 and Generation s financial statements relative to its proportionate ownership interest in each unit. In addition, Generation owns a 50.01% interest, collectively, in the CENG generating stations (Calvert Cliff Nuclear Power Plant, Nine Mile Point Nuclear Station [excluding LIPA s 18% ownership interest in Nine Mile Point Unit 2] and R.E. Ginna) which are 100% consolidated on Exelon and Generation s financial statements as of April 1, 2014. See Note 5 Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for additional information.

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 2014, 2013, and 2012 electric supply (in GWh) generated from the nuclear generating facilities was 67%, 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.

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.

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During 2014 and 2013, the nuclear generating facilities operated by Generation achieved capacity factors of 94.3% and 94.1%, respectively. The capacity factors reflect ownership percentage of stations operated by Generation and include CENG as of April 1, 2014. 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 assesses unit performance indicators and inspection results, and communicates its assessment on a semi-annual basis. As of December 31, 2014, the NRC categorized Calvert Cliffs unit 2, Clinton, Limerick units 1 and 2, and Oyster Creek 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, 2014, which is the highest performance band. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures for nuclear generating facilities and/or increased operating costs of nuclear generating units.

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.

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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 Unit 1, Calvert Cliffs Units 1 and 2, Nine Mile Point Units 1 and 2, R.E. Ginna Unit 1, Three Mile Island Unit 1 and Limerick Units 1 and 2. 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
Calvert Cliffs (c)	1	1975	2034
	2	1977	2036
Clinton	1	1987	2026
Dresden (c)	2	1970	2029
	3	1971	2031
LaSalle (d)	1	1984	2022
	2	1984	2023
Limerick (c)	1	1986	2044
	2	1990	2049
Nine Mile Point (c)	1	1969	2029
	2	1988	2046
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
R.E. Ginna (c)	1	1970	2029
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) In May 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 renewed operating licenses.
(d) In December 2014, Generation submitted applications to the NRC to extend the operating licenses of LaSalle 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 currently has license renewal applications pending for Braidwood Units 1 and 2, Byron Units 1 and 2, and LaSalle Units 1 and 2. Generation has advised the NRC that any license renewal application for Clinton would not be filed until the first quarter of 2021. 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 operating 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.

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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 393 MWs of new nuclear generation at a cost of $1,193 million, which has been capitalized to property, plant and equipment on Exelon s and Generation s Consolidated Balance Sheets. At December 31, 2014, Generation has capitalized $122 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 139 MWs of new nuclear generation that is in the installation phase at one nuclear station, Peach Bottom in Pennsylvania. The remaining spend associated with this project is expected to be approximately $125 million through the end of 2016. Generation believes that it is probable that this project 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, 2014, Generation had approximately 73,800 SNF assemblies (18,300 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 Asset Retirement Obligations 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 are anticipated to 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 losing full core offload capability in 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 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

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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 ships its Class A LLRW, which represents 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 utilizes on-site storage capacity at its Peach Bottom and LaSalle stations to store Class B and Class C LLRW for all stations in Generation s nuclear fleet, as approved by the NRC. Generation has a contract through 2032 to ship Class B and Class C LLRW to a disposal facility in Texas. The agreement provides for disposal of all current Class B and Class C LLRW currently stored at the Peach Bottom and LaSalle stations as well as the Class B and Class C LLRW generated during the term of the agreement. However, because the production of LLRW from Generation s nuclear fleet will exceed the capacity at the Texas site (3.9 million curies for 15 years beginning in 2012), Generation will still be required to utilize on-site storage at its Peach Bottom and LaSalle stations for Class B and Class C LLRW. Generation currently has enough storage capacity to store all Class B and C LLRW for the life of all stations in Generation s nuclear fleet. Generation continues to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize cost impacts and on-site storage.

Nuclear Insurance. Generation is subject to liability, property damage and other risks associated with 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 Commitments and Contingencies 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 Note 3 Regulatory Matters, Note 11 Fair Value of Financial Assets and Liabilities and Note 15 Asset Retirement Obligations 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 liabilities to

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decommission Dresden Unit 1 and Peach Bottom Unit 1 as of December 31, 2014 were $188 million and $111 million, respectively. As of December 31, 2014, NDT funds set aside to pay for these obligations were $459 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 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning and see Note 2 Variable Interest Entities 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 12,949 MW of capacity in fossil and renewable generating facilities currently in service (excluding Quail Run, which was sold on January 21, 2015). Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) jointly owned facilities that include Wyman; (2) an ownership interest through an equity method investment in Sunnyside; and (3) certain wind project entities with minority interest owners, see Note 2 Variable Interest Entities 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 LaPorte, Sunnyside and Wyman, which are operated by third parties. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information relating to the sale of the Quail Run generating facility. In 2014 and 2013, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 13% and 15%, 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 Exelon Generation Company, LLC 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 Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively. Based on the FERC procedural schedule, the FERC licensing process was not completed prior to the expiration of Muddy Run s license on August 31, 2014, and the expiration of Conowingo s license on September 1, 2014. FERC is required to issue annual licenses for the facilities

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until the new licenses are issued. On September 10, 2014, FERC issued annual licenses for Conowingo and Muddy Run, effective as of the expiration of the previous licenses. If FERC does not issue new licenses prior to the expiration of annual licenses, the annual licenses will renew automatically. The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. Refer to Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements 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, unless required by financing agreements. 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 Exelon Generation Company, LLC.

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, 2014:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic	19	2015 - 2032	860
Midwest	7	2015 - 2022	1,734
New England	15	2015 - 2020	1,401
ERCOT	5	2020 - 2031	1,534
Other Regions	15	2015 - 2030	4,045
Total	61		9,574

	2015	2016	2017	2018	2019
Capacity Expiring (MW)	2,726	73	1,965	101	631

Fuel

The following table shows sources of electric supply in GWh for 2014 and 2013:

	Source of Electric Supply	
	2014	2013
Nuclear [(a)]	166,454	142,126
Purchases non-trading portfolio [(b)]	48,200	69,791
Fossil (primarily natural gas)	26,324	30,785

Renewable [c]	6,429	6,420
Total supply	247,407	249,122

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g., CENG). Nuclear generation for 2014 and 2013 includes physical volumes of 25,053 GWh and 0 GWh, respectively, for CENG.

(b) Purchased power for 2014 and 2013 includes physical volumes of 5,346 GWh and 24,232 GWh, respectively, as a result of the PPA with CENG. On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, 100% of CENG volumes are included in nuclear generation.

(c) Includes hydroelectric, wind, and solar generating assets.

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The fuel costs per MWh 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 2015. All of Generation s enrichment requirements have been contracted through 2020. 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 Derivative Financial Instruments 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, including tolling agreements, 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 also buy power to meet the energy demand of its customers. 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

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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. Additionally, Generation is involved in the development, exploration, and harvesting of oil, natural gas and natural gas liquids properties (Upstream).

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 commodity price risk in 2015 and beyond for portions of its electricity portfolio that are unhedged. Generation has been and will continue to be proactive in using hedging strategies to mitigate this risk in subsequent years. This strategy has not changed as a result of recent and pending asset divestitures. As of December 31, 2014, the percentage of expected generation hedged for the major reportable segments was 93%-96%, 61%-64% and 31%-34% for 2015, 2016, and 2017, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation (which reflects the divestiture impact of Quail Run). Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. 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. The corporate risk management group and Exelon s RMC monitor the financial risks of the wholesale and retail power marketing activities. Generation also uses financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of Generation s efforts. 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 limits, to manage exposure to market risk. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

At December 31, 2014, 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)]	Total
2015	$ 418	$ 152	$ 20	$ 590
2016	283	228	15	526
2017	222	121	15	358
2018	112	29	16	157
2019	117	5	16	138
Thereafter	279	1	35	315
Total	$ 1,431	$ 536	$ 117	$ 2,084

(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, 2014, net of fixed capacity payments expected to be received (Capacity offsets) by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. As of December 31, 2014, capacity offsets were $132 million, $133 million, $136 million, $137 million,$138 million, and $591 million for years 2015, 2016, 2017, 2018, 2019, and thereafter, respectively. Expected payments include certain fixed capacity charges which may be reduced based on plant availability.

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(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.

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 2015 are as follows:

(in millions)	
Nuclear fuel [(a)]	$ 1,250
Production plant	1,800
Renewable energy projects	225
Maryland commitments	225
Other	125
Total	$ 3,625

(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 electricity 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 2015 to 2066. ComEd anticipates working with the appropriate governmental bodies 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 16,515 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 number of retail customers participating in customer choice programs was 2,426,921, 2,630,185 and 1,627,150 at December 31, 2014, 2013 and 2012, respectively, representing 63.0%, 68% and 43% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 80%, 81% and 65% of ComEd s retail kWh sales for the years ended December 31, 2014, 2013 and 2012, respectively.

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 or ComEd s financial position. 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 Note 24 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers, net income and total assets.

Under Illinois law, ComEd is required to deliver electricity to all customers within ComEd s service territory. 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.

EIMA is scheduled to sunset, ending ComEd s performance based rate formula and investment commitment, at December 31, 2017, unless approved to continue through 2022 by the Illinois General Assembly. During the fourth quarter of 2014, the Illinois House and Senate each passed House Bill 3975 which extends the date of the EIMA sunset from 2017 to 2019. The bill was presented to the Governor on February 11, 2015. The Governor can either act on the bill or, after 60 days, the bill will automatically become law.

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. ComEd s allowed rate of return on common equity is the annual average rate on 30-year treasury notes plus 580 basis points, subject to a (collar) of plus or minus 50 basis points. The collar, therefore limits favorable and unfavorable impacts of weather and load on distribution revenue. In addition, ComEd s allowed 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 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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Procurement-Related Proceedings. ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. 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. Charges incurred for electric supply procured through contracts with Generation are included in Purchased power from affiliates on ComEd s Statement of operations and Comprehensive Income.

See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s procurement plans.

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

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 June 11, 2014, the ICC approved ComEd s request to accelerate the deployment, which allows for the installation of more than four million smart meters throughout ComEd s service territory by 2018, three years in advance of the originally scheduled 2021 completion date. To date, nearly 550,000 smart meters have been installed in the Chicago area by ComEd.

Energy Efficiency Programs. 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 January 2014, the ICC approved ComEd s third three-year Energy Efficiency and Demand Response Plan covering the period June 2014 through May 2017. The plans are designed to meet Illinois energy efficiency and demand response goals through May 2017, 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 through 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 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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Construction Budget

ComEd s business is capital intensive and requires significant investments, primarily in electricity transmission and electricity distribution facilities, to ensure the adequate capacity, reliability and efficiency of its system. Such investments include capital program and modernization pursuant to EIMA, and transmission upgrades and expansion including the Grand Prairie Gateway Transmission Line project, and PJM s RTEP. ComEd s most recent estimate of capital expenditures for electric plant additions and improvements for 2015 is $2,200 million.

See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional details. 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 electricity 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 4.0 million, including approximately 1.6 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 506,000 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, with all of such 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 7,166 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.

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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, 2014, there were 101 competitive electric generation suppliers serving PECO customers. At December 31, 2014, the number of retail customers purchasing energy from a competitive electric generation supplier was 546,900 representing approximately 34% of total retail customers. Retail deliveries purchased from competitive electric generation suppliers represented approximately 70% of PECO s retail kWh sales for the year ended December 31, 2014. 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 PECO s electric revenue net of purchased power expense or 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 revenue or purchased 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.

See Note 24 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers, net income and total assets.

Procurement-Related Proceedings. PECO s electric supply for its customers is procured through contracts executed in accordance with its PAPUC-approved DSP Programs.

On October 12, 2012, the PAPUC approved PECO s second DSP Program, which was filed with the PAPUC in January 2012. The plan outlined how PECO purchased electric supply for default service customers from June 1, 2013 through May 31, 2015. Pursuant to the second DSP Program, PECO procured 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. PECO entered into contracts with PAPUC approved bidders, including Generation, for its five competitive procurements. 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. By Order entered on January 24, 2014, the PAPUC approved PECO s plan, with modifications, to make CAP shopping available beginning April 15, 2014. On March 20, 2014, low-income advocacy groups filed an appeal and emergency request for a stay with the Pennsylvania Commonwealth Court, claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On March 28, 2014, the Commonwealth Court issued the requested stay, pending a full review of the appeal. Pending the Commonwealth Court s review, PECO will not implement CAP Shopping. The Commonwealth Court s decision is expected in 2015.

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On March 10, 2014, PECO filed its third DSP Program with the PAPUC. The program has a 24-month term from June 1, 2015 through May 31, 2017, and complies with electric generation procurement guidelines set forth in Act 129. On August 28, 2014, PECO filed a Joint Petition for Partial Settlement, which affirmed PECO s procurement plan for residential and small commercial customers. On December 4, 2014, the PAPUC approved PECO s third DSP Program, as modified by the Joint Petition for Partial Settlement, without modification or limitation. Separate from the Joint Petition for Partial Settlement, the PAPUC also approved other items related to the program. The plan outlines how PECO will purchase electric supply for default service customers. PECO will procure electric supply through four competitive procurements for fixed price full requirements contracts of two years or less for the residential classes and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load.

See Note 3 Regulatory Matters 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 was awarded $200 million, the maximum grant allowable under the program, for its SGIG project Smart Future Greater Philadelphia. As of December 31, 2014, PECO has received all of the $200 million, including $4 million for sub-recipients, in reimbursements. The SGIG funds have been used by PECO to offset the total impact to ratepayers of the smart meter deployment required by Act 129. 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. Under PECO s universal deployment plan, PECO will deploy all of the 1.7 million electric smart meters on an accelerated basis by the second quarter of 2015. In total, PECO currently expects to spend up to $583 million and $155 million on its smart meter and smart grid infrastructure, respectively, before considering the $200 million SGIG funds. As of December 31, 2014, PECO has spent $540 million and $119 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received.

See Note 3 Regulatory Matters 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 set forth how PECO would meet the required reduction targets established by Act 129 s EE&C provisions, which included a 3.0% 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. On March 20, 2014, the PAPUC issued its final report stating that PECO was in full compliance with all Phase I targets.

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 with a three-year cumulative consumption reduction target of 1,125,852 MWh.

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. In its February 20, 2014 Final Order, the PAPUC stated that it does not expect to

make a decision as to whether it will prescribe additional demand response obligations until 2015. Any decision reached would affect PECO s EE&C Plan subsequent to its Phase II Plan.

On February 28, 2014, 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, 2014 to May 31, 2016. PECO proposed to fund the estimated $10 million annual costs of the program by modifying incentive levels for other Phase II programs. The costs of the DLC program will be recovered through PECO s Energy Efficiency Program Charge along with other Phase II Plan costs. The PAPUC granted PECO s Petition in an Order that became final on May 5, 2014.

Pennsylvania Retail Electricity Market. The extreme weather experienced in early 2014 resulted in increased commodity costs causing certain shopping customers to receive unexpectedly high utility bills. In response to a significant number of customer complaints throughout Pennsylvania, on April 3, 2014, the PAPUC unanimously voted to adopt two rulemaking orders to address the issue. The first rulemaking order requires electric generation suppliers to provide more consumer education regarding their contracts. The second rulemaking order requires electric distribution companies to enable customers to switch suppliers within three business days (known as accelerated switching). The improved customer education and accelerated switching were to be in place within 30 days and six months of approval of the orders, respectively. The orders became final on June 14, 2014. On December 4, 2014, the PAPUC approved PECO s implementation plan (known as Bill on Supplier Switch), allowing PECO to implement accelerated switching by the December 15, 2014 deadline.

See Note 3 Regulatory Matters 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, 2014, the number of retail customers purchasing natural gas from a competitive natural gas supplier was 78,400, representing approximately 15% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 22% of PECO s mmcf sales for the year ended December 31, 2014. PECO provides distribution, billing, metering, installation, maintenance and emergency response services at regulated rates to all its customers in its service territory.

Procurement-Related 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 32 million dekatherms. Peak natural gas is provided by PECO s liquefied natural gas (LNG) facility and propane-air plant which provide 1.2 billion cubic feet and 181,441 dekatherms, respectively, on an annual basis. PECO also has under contract 21 million dekatherms of underground storage through service agreements. Natural gas from underground storage represents approximately 29% of PECO s 2014-2015 heating season planned supplies.

Gas Main Extension Program. On November 6, 2014, PECO filed a plan with the PAPUC requesting approval of three initiatives to provide more incentives to customers interested in switching to natural gas service. If approved, local customers would pay significantly less initially to have natural gas installed at their homes and businesses.

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See Note 3 Regulatory Matters 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. PECO s most recent estimate of capital expenditures for plant additions and improvements for 2015 is $550 million, which includes RTEP projects and capital expenditures related to the smart meter and smart grid project.

See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional details. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for further information.

BGE

BGE is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity 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 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 nonexclusive 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.

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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 commercial 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 are 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 BGE s electric revenue net of purchased power expense or financial position. At December 31, 2014, there were 59 competitive electric generation suppliers serving BGE customers. At December 31, 2014, the number of retail customers purchasing energy from a competitive electric generation supplier was approximately 364,000, representing 29% of total retail customers. Retail deliveries purchased from competitive electric generation suppliers represented approximately 60% of BGE s retail kWh sales for the year ended December 31, 2014.

See Note 24 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers, net income and total assets.

Procurement Related Proceedings. 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. Charges incurred for electric supply procured through contracts with Generation are included in Purchased power from affiliates on BGE s Statement of Operations and Comprehensive Income.

See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on BGE s procurement plan.

Electric Distribution Rate Case. On July 2, 2014, and as amended on September 15, 2014, BGE filed for an electric base rate increase with the MDPSC, ultimately requesting an increase of $99 million. On October 17, 2014, BGE filed with the MDPSC a unanimous settlement agreement (the

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Settlement Agreement) reached with all parties to the case under which it would receive an increase of $22 million in electric base rates. The Settlement Agreement establishes new depreciation rates which have the effect of decreasing annual electric depreciation expense by approximately $22 million. On December 4, 2014, the Public Utility Law Judge issued a proposed order approving the Settlement Agreement without modification, which became a final order on December 12, 2014. The approved electric distribution rate became effective for services rendered on or after December 15, 2014.

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

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 was awarded $200 million, the maximum grant allowable under the program, to support its Smart Grid, Peak Rewards and CC&B initiatives, of which BGE had been fully reimbursed for as of December 31, 2013. The SGIG funding significantly reduced the rate impact of those investments on BGE customers.

See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding BGE s Smart Meter Programs.

Energy Efficiency Programs. BGE s energy efficiency programs include a lighting program, retrofit programs, incentives for energy efficient new homes, rebates for heating and cooling systems, energy audits, an energy efficient appliance rebate and trade-in program, customer incentives for non-profit, educational, governmental and business customers, energy management programs and bill credits to help residential customers reduce energy demand during peak periods. The MDPSC initially approved a full portfolio of conservation programs in 2008 as well as a customer surcharge to recover the associated costs in 2009. This customer surcharge is updated annually. In December 2011, the MDPSC approved BGE s conservation programs for implementation in 2012 through 2014. On December 23, 2014, the MDPSC approved BGE s proposal for the 2015-2017 programs with minor modifications.

See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding BGE s Energy Efficiency Programs.

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. 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.

Customer choice program activity affects revenue collected from customers related to supplied natural gas; however, that activity has minimal impact on BGE s gas revenue net of purchased power expense or financial position. At December 31, 2014, there were 40 competitive natural gas suppliers serving BGE customers. At December 31, 2014, the number of retail customers purchasing fuel from a

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competitive natural gas supplier was approximately 161,000 representing 25% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 53% of BGE s retail mmcf sales for the year ended December 31, 2014.

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 354 mmcf per day.

BGE s current maximum storage entitlements are 312 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 Case. On July 2, 2014, and as amended on September 15, 2014, BGE filed for a gas base rate increase with the MDPSC, ultimately requesting an increase of $68 million. On October 17, 2014, BGE filed with the MDPSC the Settlement Agreement reached with all parties to the case under which it would receive an increase of $38 million in gas base rates. The Settlement Agreement establishes new depreciation rates which have the effect of increasing annual gas depreciation expense by approximately $2 million. On December 14, 2014, the Public Utility Law Judge issued a proposed order approving the Settlement Agreement without modification, which became a final order on December 12, 2014. The approved gas distribution rate became effective for services rendered on or after December 15, 2014.

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

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 BGE s most recent estimate of capital expenditures for plant additions and improvements for 2015 is approximately $700 million.

See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional details. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for further information.

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 PECO s 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 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding transmission services.

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Employees

As of December 31, 2014, Exelon and its subsidiaries had 28,993 employees in the following companies, of which 9,276 or 32% 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 (e)	1,690	96	2,353	4,139	14,370
ComEd	3,739			3,739	6,403
PECO		1,282		1,282	2,458
BGE					3,252
Other (d)	72		44	116	2,510
Total	5,501	1,378	2,397	9,276	28,993

(a) A separate CBA between ComEd and IBEW Local 15 covers approximately 55 employees in ComEd s System Services Group and expires in 2015. Generation s and ComEd s separate CBAs with IBEW Local 15 was renewed in 2014 and expires in 2019.
(b) 1,378 PECO craft and call center employees in the Philadelphia service territory are covered by CBAs with IBEW Local 614. The CBAs expire in 2019. Additionally, Exelon Power, an operating unit of Generation, has an agreement with IBEW Local 614, which expires in 2016 and covers 96 employees.
(c) During 2014, Generation finalized CBAs with TMI Local 777 and Oyster Creek Local 1289, expiring in 2019 and 2021, respectively and CENG finalized its CBA with Nine Mile Point which will expire in 2020. Additionally, during 2014, Generation finalized CBAs with the Security Officer unions at Dresden, LaSalle, Limerick and Quad Cities, which expire between 2017 and 2018. Lastly, during 2014, an agreement was negotiated with Las Vegas District Energy and IUOE Local 501, which will expire in 2018. During 2013, two other 3-year agreements were negotiated: 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 a CBA with the Security Officer unions at Braidwood, which expires in 2015.
(d) Other includes shared services employees at BSC.
(e) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the total includes CENG employees as of December 31, 2014.

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, 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.

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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 (SO2), nitrogen oxides (NOx), 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.

See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information regarding clean air regulation in the forms of the CSAPR, 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. 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.

Section 316(b) of the Clean Water Act. Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation s 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 October 14, 2014, the U.S. EPA s final Section 316(b) rule became effective. The rule requires that a series of studies and analyses be performed to determine the best technology available, followed by an implementation period. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director.

The rule does not require closed-cycle cooling (e.g., cooling towers) as the best technology available to address impingement and entrainment of aquatic life at a facility s cooling water intake structure. The rule provides the state permitting director with significant discretion to determine the best technology available to limit entrainment (drawing aquatic life into the plants cooling system) mortality, including application of a cost-benefit test and the consideration of a number of site-specific factors. After consideration of these factors, the state permitting agency may require closed cycle cooling, an alternate technology, or determine that the current technology is the best available. The rule also provides a number of flexible compliance options to reduce impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or other technology at the intake. A number of concerns raised by the electric generation industry about the proposed rule were resolved favorably in the final rule.

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Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, Generation cannot estimate the effect that compliance with the rule will have on the operation of its and CENG s generating facilities and its future results of operations, cash flows capital expenditures, and financial position. Should a state permitting director determine that a facility must install cooling towers to comply with the rule, that facility s economic viability would be called into question. However, the likely impact of the rule has been significantly decreased since the final rule does not mandate cooling towers as a national standard, and the state permitting director is required to apply a cost-benefit test and can take into consideration site-specific factors.

New York Facilities. In July 2011, the New York Department of Environmental Conservation (DEC) issued a policy regarding the best available technology for cooling water intake structures. Through its policy, the DEC established closed-cycle cooling or its equivalent as the performance goal for all existing facilities, but also provided that the DEC will select a feasible technology whose costs are not wholly disproportionate to the environmental benefits to be gained and allows for a site-specific determination where the entrainment performance goal cannot be achieved. Each of CENG s New York facilities received renewals of their SPDES permits in 2014.

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. However, it is unknown at this time whether implementation of the final EPA rule will result in a requirement to install closed cycle cooling at Salem.

Solid and Hazardous Waste

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.

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See Note 22 Commitments and Contingencies 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 2015 at Exelon for compliance with environmental remediation related to contamination at former MGP sites is expected to total $35 million, consisting of $29 million, $6 million and $0 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, 2014, 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 Regulatory Matters and 22 Commitments and Contingencies 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 positions.

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 issued in 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 2014, 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.

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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. At COP 20 held in Lima, Peru, in December 2014, participating countries outlined the universal GHG reduction agreement to be finalized in 2015 at COP 21 in Paris. On November 11, 2014, President Obama and President Xi Jinping of China jointly announced their respective intended nationally determined contributions for post 2020 greenhouse gas emission reductions. The US announced net greenhouse gas emission reductions of 26-28 percent below 2005 levels by 2025, while China announced targets to peak CO_2 emissions around 2030, and to increase the non-fossil fuel share of all energy to around 20 percent by 2030. Together, the U.S. and China account for over one third of global greenhouse gas emissions.

Federal Climate Change Legislation and Regulation. Various stakeholders, including Exelon, legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors are considering ways to address the climate change issue, 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 (CO_2) 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 CO_2 emissions for new fossil-fuel electric generating units, particularly coal-fired units. Under the President s memorandum, the U.S. EPA was also required to propose a Section 111(d) rule no later than June 1, 2014 to establish CO_2 emission regulations for existing stationary sources. The second rulemaking, under Section 111(d) of the Clean Air Act, focuses on modified, reconstructed and existing fossil power plants. The proposed rule was published in the Federal Register on June 18, 2014, and the public comment period closed on December 1, 2014. The Climate Action Plan calls for the rule to be finalized no later than June 1, 2015, and requires that states submit to U.S. EPA their implementation plans no later than June 30, 2016.

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 the regional RGGI CO_2 budget was reduced, starting in 2014, from its previous 165 million ton level to 91 million tons, with a 25 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 CO_2 allowances

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available for purchase at auction. (CCR trigger prices are $4 in 2014, $6 in 2015, $8 in 2016 and $10 in 2017, after 2017 the CCR price increases by 2.5 percent each year). 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 was chartered in 2007 and released a 42 greenhouse gas reduction strategy, climate action plan, on August 27, 2008. The plan s primary policy recommendation to formally 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) which requires Maryland to reduce its GHG emissions by 25 percent below 2006 levels by 2020. It also directed the Maryland Department of Environment to prepare and implement an action plan which was published in October of 2013. Maryland s electricity consumption reduction goals, required under the Empower Maryland program, and mandatory State participation in RGGI Program, are listed as the energy sector s contribution in the plan. The plan also advocated raising the renewable portfolio standard requirement from 20% by 2022 to 25% by 2022. The Department of Environment is required to submit a December 2015 report to the Governor and General Assembly on progress towards the 25% mandate; its costs and benefits; the need for target adjustments; and the status of federal programs. In 2016, the Legislature will review the progress report, its economic impacts on manufacturing sector and other information and determine whether to continue, adjust or eliminate the requirement to achieve a 25% reduction by 2020.

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.

Based on an independent third-party verification of Exelon s GHG performance through year-end 2013, it achieved the Exelon 2020 goal of abating 17.5 million tonnes of GHG emissions annually, seven years ahead of plan. Exelon s approach for addressing the issue of climate change is currently focused on continuing to manage its GHG emissions from internal operations, contributing to reducing overall grid GHG emissions and ensuring the resiliency of its infrastructure in response to the physical impacts of climate change.

Renewable and Alternative Energy Portfolio Standards

Thirty-nine states and the District of Columbia have adopted some form of RPS requirement. 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.

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Illinois utilities are 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 by Illinois legislation. As of December 31, 2014, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois 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 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s procurement plans. See Note 22 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding ComEd s future commitments for the procurement of RECs.

The AEPS Act became effective for PECO on January 1, 2011. During 2014, PECO was required to supply approximately 4.5% 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, 2014 and subsequently 5.0% beginning June 1, 2014 and continuing through May 31, 2015. 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, 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 2014, 10.3% was required from Tier 1 renewable sources, including at least 0.35% derived from solar energy, and 2.5% from Tier 2 renewable sources. 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 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 Regulatory Matters and Note 22 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

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Executive Officers of the Registrants as of February 13, 2015

Exelon

Name	Age	Position	Period
Crane, Christopher M.	56	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.	49	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.	54	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
Pramaggiore, Anne R.	56	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
Adams, Craig L.	62	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Butler, Calvin G.	45	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
		Senior Vice President, Human Resources, Exelon	2010 - 2011
		Senior Vice President, Corporate Affairs, ComEd	2009 - 2010
Von Hoene Jr., William A.	61	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
		Executive Vice President, Finance and Legal, Exelon	2009 - 2012
Thayer, Jonathan W.	43	Senior Executive Vice President and Chief Financial Officer, Exelon	2012 - Present [(a)]
		Senior Vice President and Chief Financial Officer, Constellation Energy; Treasurer, Constellation Energy	2008 - 2012
Aliabadi, Paymon	52	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
DesParte, Duane M.	51	Senior Vice President and Corporate Controller, Exelon	2008 - Present

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Generation

Name	Age	Position	Period
Cornew, Kenneth W.	49	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
Nigro, Joseph	50	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
Pacilio, Michael J.	54	Executive Vice President and Chief Operating Officer, Exelon Generation	2015 - Present
		President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	2010 - 2015
		Chief Operating Officer, Exelon Nuclear	2007 - 2010
Hanson, Bryan C.	49	President and Chief Nuclear Officer, Exelon Nuclear; Senior Vice President, Exelon Generation	2015 - Present
		Chief Operating Officer, Exelon Nuclear	2014 - 2015
		Senior Vice President of Operations, Generation	2010 - 2013
		Vice President of Operations, Generation	2009 - 2010
DeGregorio, Ronald	52	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.	48	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	48	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

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ComEd

Name	Age	Position	Period
Pramaggiore, Anne R.	56	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
Donnelly, Terence R.	54	Executive Vice President and Chief Operating Officer, ComEd	2012 - Present
		Executive Vice President, Operations, ComEd	2009 - 2012
Trpik Jr., Joseph R.	45	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 - Present
Jensen, Val	59	Senior Vice President, Customer Operations, ComEd	2012 - Present
		Vice President, Marketing and Environmental Programs, ComEd	2008 - 2012
O Neill, Thomas S.	52	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2010 - Present
		Senior Vice President, Exelon	2009 - 2010
Marquez Jr., Fidel	53	Senior Vice President, Governmental and External Affairs, ComEd	2012 - Present
		Senior Vice President, Customer Operations, ComEd	2009 - 2012
Brookins, Kevin B.	53	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	50	Senior Vice President, Distribution Operations, ComEd	2010 - Present
		Vice President, Transmission and Substations, ComEd	2007 - 2010
Kozel, Gerald J.	42	Vice President, Controller, ComEd	2013 - Present
		Assistant Corporate Controller, Exelon	2012 - 2013
		Director of Financial Reporting and Analysis, Exelon	2009 - 2012

PECO

Name	Age	Position	Period
Adams, Craig L.	62	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Barnett, Phillip S.	51	Senior Vice President and Chief Financial Officer, PECO	2007 - Present
		Treasurer, PECO	2012 - Present
Innocenzo, Michael A.	49	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

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Name	Age	Position	Period
Webster Jr., Richard G.	53	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
		Director of Rates and Regulatory Affairs	2007 - 2012
Murphy, Elizabeth A.	55	Vice President, Governmental and External Affairs, PECO	2012 - Present
		Director, Governmental & External Affairs, PECO	2007 - 2012
Jiruska, Frank J.	54	Vice President, Customer Operations, PECO	2013 - Present
		Director of Energy and Marketing Services, PECO	2010 - 2013
Diaz Jr., Romulo L.	68	Vice President and General Counsel, PECO	2012 - Present
		Vice President, Governmental and External Affairs, PECO	2009 - 2012
Bailey, Scott A.	38	Vice President and Controller, PECO	2012 - Present
		Assistant Controller, Generation	2011 - 2012
		Director of Accounting, Power Team	2007 - 2011

BGE

Name	Age	Position	Period
Butler, Calvin G.	45	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
		Senior Vice President, Human Resources, Exelon	2010 - 2011
		Senior Vice President, Corporate Affairs, ComEd	2009 - 2010
Woerner, Stephen J.	47	President, BGE	2014 - Present
		Chief Operating Officer, BGE	2012 - Present
		Senior Vice President, BGE	2009 - 2014
		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
Vahos, David M.	42	Chief Financial Officer and Treasurer	2014 - Present
		Vice President and Controller, BGE	2012 - 2014
		Executive Director, Audit, Constellation	2010 - 2012
		Director, Finance, BGE	2006 - 2010
Case, Mark D.	53	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
		Senior Vice President, Strategy and Regulatory Affairs, BGE	2007 - 2012
Biagiotti, Robert D.	45	Vice President, Customer Operations and Chief Customer Officer, BGE	2015 - Present
		Vice President, Gas Distribution, BGE	2011-2015
		Director, Gas and Electric Field Services, BGE	2008-2011

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Name	Age	Position	Period
Gahagan, Daniel P.	61	Vice President and General Counsel, BGE	2007 - Present
Bauer, Matthew N.	38	Vice President and Controller, BGE	2014 - Present
		Vice President of Power Finance, Exelon Power	2012 - 2014
		Director, FP&A and Retail, Constellation	2012 - 2012
		Executive Director, Corporate Development, Constellation	2009 - 2012

(a) Effective July 1, 2014, Jonathan W. Thayer s title was changed from Executive Vice President and Chief Financial Officer, Exelon to Senior Executive Vice President and Chief Financial Officer, Exelon.

ITEM 1A. RISK FACTORS

Each of the Registrants operates in a market and regulatory environment that poses significant risks, many of which are beyond that 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 committee 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.

Exelon s financial condition and results of operations are affected to a significant degree by: (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. Factors that affect the financial condition and results of operations of the Registrants fall primarily under the following categories, all of which are discussed in further detail below:

Market and Financial Factors. Exelon s and Generation s results of operations are affected by price fluctuations in the energy 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 price of natural gas, which affects the prices that Generation can obtain for the output of its power plants, (2) the presence of other generation resources in the markets in which Generation s output is sold, (3) the demand for electricity in the markets where the Registrants conduct their business, and (4) the impacts of on-going competition in the retail channel.

Regulatory and Legislative Factors. The regulatory and legislative factors that may affect the Registrants 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 affected by changes in the design of competitive wholesale power markets or Generation s ability to sell power in those markets. In addition, potential regulation and legislation, including legislation or regulation regarding climate change and renewable portfolio standards, could have significant effects on the Registrants. Also, returns for ComEd, PECO and BGE are influenced significantly by state regulation and regulatory proceedings.

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Operational Factors. The Registrants operational performance is subject to those factors 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 their customers and regulators, are affected by those companies ability to maintain the reliability and safety of their energy delivery systems.

Risks Related to the Pending Merger with PHI. There are various risks and uncertainties associated with the merger agreement announced with PHI on April 29, 2014.

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

Market and Financial Factors

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. 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 tepid economic environment in recent years 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 periods 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

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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.

Market Designs. The wholesale markets remain evolving markets that vary from region to region and are still developing rules, practices and procedures. Changes in these market rules, problems with rule implementation, or 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 affected by 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 affect 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 may 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 OPEB plan assets will increase the funding requirements associated with Exelon s pension and OPEB plan obligations. Additionally, Exelon s pension and OPEB 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 OPEB 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 are 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, 2014, approximately 29%, or $2.5 billion of the Registrants available credit facilities were with European banks, excluding the unsecured bridge facility to provide financing for the proposed PHI acquisition. The credit facilities include $8.5 billion in aggregate total commitments of which $7.3 billion was available as of December 31, 2014. There were no borrowings under the Registrants credit facilities as of December 31, 2014. See Note 13 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the credit facilities.

The strength and depth of competition in 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, PECO s and BGE s operating agreements with PJM and PECO s and BGE s natural gas procurement contracts contain collateral provisions that are affected by their credit rating and market prices. If certain wholesale market conditions were to exist and ComEd, 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 forms of letters of credit or cash, which may have a material adverse effect upon their liquidity. Collateral posting requirements will generally increase as market prices rise and decrease as market prices fall. Collateral posting requirements for PECO and BGE, with respect to their natural gas supply 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 ComEd, PECO and 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 ring-fencing) 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 ring-fencing 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 and cash flows 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

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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 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 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 might 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 31, 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, 2014, 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 $810 million, of which approximately $310 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 $90 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 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

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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 Significant Accounting Policies and Note 14 Income Taxes 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 a return 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 60%, 51%, 62%, 68% and 77% of total assets for Exelon, Generation, ComEd, PECO and BGE, respectively, as of December 31, 2014. In addition, Exelon and Generation have significant balances related to unamortized energy contracts. See Note 4 Mergers, Acquisitions, and Dispositions and Note 10 Intangible Assets 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 holds investments in coal-fired plants in Georgia that are subject to long-term leases. The investments are accounted for as direct financing lease investments. The investments represent the estimated residual value of the leased assets at the end of the lease term. 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 $2.7 billion of goodwill recorded at December 31, 2014 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 to expense, which will also reduce equity. The actual timing and amounts of any goodwill impairments will depend on many sensitive, interrelated and uncertain variables. A successful IRS challenge to

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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 Note 7 Property, Plant and Equipment, Note 8 Impairment of Long Lived Assets and Note 10 Intangible Assets 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 electric generating facilities 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 of electric or gas systems or infrastructure 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 Factors

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

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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. Similarly, final regulations under Section 111(d) of the Clean Air Act may not provide sufficient incentives for states to utilize carbon-free nuclear power as a means of meeting greenhouse gas emission reduction requirements, while continuing a policy of favoring renewable energy sources. 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 Regulatory Matters 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. As of December 31, 2014, Generation has submitted its triennial application seeking reauthorization to sell at market-based rates in the Southeast region. Generation s previous submission seeking reauthorization to sell at market-based rates was accepted by FERC on August 5, 2014 for the Northeast region (including PJM).

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was enacted in July 2010. The part of the Act that applies to Exelon is Title VII, which is known as the Dodd-Frank Wall Street Transparency and Accountability Act (Dodd-Frank). Dodd-Frank requires the creation of a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing for certain categories of Swaps, incentives to shift Swap activity to exchange trading, margin and capital requirements, and other obligations designed to promote transparency. For non security-based Swaps including commodity Swaps, Dodd-Frank empowers the Commodity Futures Trading Commission (CFTC) to promulgate regulations implementing the law s objectives. The primary aim of Dodd-Frank is to regulate the key intermediaries in the Swaps market, which entities are either swap dealers (SDs), major swap participants (MSPs), and certain other financial entities, but the law also applies to a lesser degree to end-users of Swaps. On January 12, 2015, President Obama signed into law a bill that exempts from margin requirements Swaps used by end-users to hedge or mitigate commercial risk. Moreover, the CFTC s Dodd-Frank regulations preserve the ability of end users in the energy industry to hedge their risks using Swaps without being subject to mandatory clearing, and excepts or exempts end-users from many of the other substantive regulations. Accordingly, as an end-user, Generation is conducting its commercial business in a manner that does not require registration with the CFTC as an SD or MSP. Generation does not anticipate transacting in the future in a manner in which it would become a SD or MSP.

There are, however, some rulemakings that have not yet been finalized, including the capital and margin rules for (non-cleared) Swaps. Generation does not expect these rules to directly impact its collateral requirements. However, depending on the substance of these final rules in addition to certain international regulatory requirements still under development and that are similar to Dodd-Frank, Generation s Swap counterparties could be subject to additional and potentially significant capitalization requirements. These regulations could motivate the SDs and MSPs to increase collateral requirements or cash postings from their counterparties, including Generation.

Generation continues to monitor the rulemaking proceedings with respect to the capital and margin rules, but cannot predict to what extent, if any, further refinements to Dodd-Frank requirements may impact its cash flows or financial position, but such impacts could be material.

ComEd, PECO and BGE could also be subject to some Dodd-Frank requirements to the extent they were to enter into Swaps. However, at this time, management of ComEd, PECO and BGE continue to expect that their companies will not be materially affected by Dodd-Frank.

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 and transactions incurred by ComEd, PECO, or BGE, with Generation, irrespective 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 Commitments and Contingencies 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, bad debt, 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 Regulatory Matters 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, 2014, 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 charge 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, 2014, the gain (loss) could have been as much as $(2.6) billion, $811 million and $480 million (before taxes) as a result of the elimination of ComEd s, PECO s and BGE s regulatory assets and liabilities, respectively.

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Further, Exelon would record a charge against OCI (before taxes) of up to $2.6 billion and $663 million for ComEd and BGE, respectively, related to Exelon s net regulatory assets associated with its defined benefit postretirement plans. Exelon also has a net regulatory liability of $53 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 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 Significant Accounting Policies, 3 Regulatory Matters and 10 Intangible Assets 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 CO2 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. 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 Commitments and Contingencies 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

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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. The U.S. Court of Appeals for the Seventh Circuit remanded this decision a second time. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the issue of the cost allocation for facilities 500 kV and above. 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 Note 3 Regulatory Matters and Note 22 Commitments and Contingencies 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 Commitments and Contingencies 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.

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. On September 19, 2014, the NRC issued a revised rule codifying the NRC s generic determinations regarding the environmental impacts of continued storage of spent nuclear fuel beyond a reactor s licensed operating life. The Continued Storage Rule became effective on October 20, 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. Through May 15, 2014, in accordance with the NWPA and Generation s contract with the DOE, Generation paid the DOE a fee per kWh of net nuclear generation for the cost of SNF disposal. 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 which was denied by the D.C. Circuit Court on March 18, 2014. Also, on January 3, 2014, the DOE submitted a proposal to Congress to reduce the current SNF disposal fee to zero. On May 9, 2014, the DOE notified Generation that the SNF disposal fee was set to zero, effective May 16, 2014. Until such time as a new fee structure is in effect, Exelon and Generation will not accrue any further costs related to SNF disposal fees. 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 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on the spent nuclear fuel obligation. Generation cannot predict what, if any, fee will be established in the future for SNF disposal. However, such a fee could be material to Generation s results of operations and cash flows.

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.

Operational Factors

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 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. An example of such an event was the February 5, 2014 ice storm, which interrupted electric service delivery to customers in PECO s service territory and resulted in significant restoration costs.

Another example of such an event includes 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. Natural disasters and other significant 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 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.

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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 Commitments and Contingencies 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, through PECO, has recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), it has no recourse to collect additional amounts from utility customers for any of its other nuclear units 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 Regulatory Matters 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 units, 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. Additionally, if the pledged assets are not sufficient to fund the Zion station decommissioning activities under the Asset Sale Agreement (ASA), Generation may have to seek remedies available under the ASA to reduce the risk of default by ZionSolutions and its parent. See Note 15 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

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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, 2015, and the license for the Muddy Run Pumped Storage Project expires on September 1, 2015. 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 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding proceedings related to storm-related outages in ComEd s service territory.

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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 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.

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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 continues to pursue growth in its existing businesses and markets and further diversification across the competitive energy value chain. Generation is pursuing investment opportunities in renewables, development of natural gas generation, distributed generation, potential expansion of the existing natural gas and oil Upstream and wholesale gas businesses, and entry into liquefied natural gas. 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 their regulatory-mandated Smart Grid initiatives. 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 Pending Merger with PHI

Exelon and PHI may encounter difficulties in satisfying the conditions for the completion of the Merger and the Merger may not be completed within the expected time frame or at all.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (1) the approval of the Merger by the holders of a majority of the outstanding shares of the PHI common stock, (2) the receipt of regulatory approvals required to consummate the Merger, (3) the expiration or termination of the applicable waiting period under the HSR Act and (4) other customary closing conditions, including (a) the accuracy of each party s representations and warranties (subject to customary materiality qualifiers) and (b) each party s compliance with its obligations and covenants contained in the Merger Agreement. In addition, the obligation of Exelon to consummate the Merger is subject to the required regulatory approvals not, individually or in the aggregate, imposing terms, conditions, obligations or commitments that constitute a burdensome condition (as defined in the Merger Agreement).

In addition, conditions to the completion of the Merger may fail to be satisfied. Exelon or PHI may terminate the Merger Agreement if the Merger is not completed by July 29, 2015 except that, under certain circumstances, the date may be extended by Exelon or PHI to October 29, 2015. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information regarding the status of the merger.

The Merger is subject to the receipt of consent or approval from governmental entities that could delay the completion of the Merger or impose conditions that could have a material adverse effect on the combined company or that could cause abandonment of the Merger.

Completion of the Merger is conditioned upon the receipt of consents, orders, approvals or clearances, to the extent required, from the FERC, the FCC, the District of Columbia Public Service Commission, and the public utility commissions or similar entities in certain states in which the companies operate, including the Delaware Public Service Commission, MDPSC, the New Jersey Board of Public Utilities and the Virginia

Department of Public Utilities. The Merger is also subject to review by the DOJ Antitrust Division, under the HSR Act, and the expiration or earlier termination of the waiting period (and any extension of the waiting period) applicable to the Merger is a condition to closing the Merger. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information regarding the status of regulatory approvals.

Exelon and PHI have proposed conditions for approval in some of the regulatory filings that have been made and may subsequently propose or agree to further conditions, even if such conditions could have an adverse effect on Exelon, PHI or the combined company.

Exelon cannot provide assurance that all required regulatory consents or approvals will be obtained or that these consents or approvals will not contain terms, conditions or restrictions that would be detrimental to the combined company after the completion of the Merger. The Merger Agreement generally permits Exelon to terminate the Merger Agreement if the final terms of any of the required regulatory consents or approvals include burdensome conditions (as defined in the Merger Agreement). Any substantial delay in obtaining satisfactory approvals or the imposition of any terms or conditions in connection with such approvals could cause a material reduction in the expected benefits of the Merger.

Failure to obtain regulatory approval may result in Exelon s payment of a reverse termination fee.

If the Merger Agreement is terminated under certain circumstances due to the failure to obtain regulatory approvals, the failure to obtain regulatory approvals without burdensome conditions, or the breach by Exelon of its obligations in respect of obtaining regulatory approvals, Exelon will be required to pay PHI a reverse termination fee of up to $180 million, which would occur by means of PHI s election to redeem the outstanding nonvoting preferred securities purchased by Exelon in connection with the execution of the Merger Agreement for no consideration other than the nominal par value of the stock.

Failure to complete the Merger could negatively affect the share price and the future business and financial results of Exelon.

Completion of the Merger is not assured and is subject to risks, including the risks that approval of the transaction by governmental agencies will not be obtained or that certain other closing conditions will not be satisfied. If the Merger is not completed, the ongoing businesses of Exelon may be adversely affected and Exelon will be subject to several risks, including:

- having to pay certain significant costs relating to the Merger without receiving the benefits of the Merger, including, in certain circumstances, a termination fee of up to $180 million payable by Exelon to PHI under certain circumstances; and

- the share price of Exelon may decline if and to the extent that the current market prices reflect an assumption by the market that the Merger will be completed.

Exelon and PHI have incurred and will incur significant transaction and Merger-related costs in connection with the Merger.

Exelon and PHI have incurred and expect to incur additional non-recurring costs associated with combining the operations of the two companies. Most of these costs will be transaction costs, including fees paid to financial and legal advisors related to the Merger and related financing arrangements, and employment-related costs, including change-in- control related payments made to certain PHI executives. In addition, if the closing of the Merger is materially delayed, Exelon may be required to pay financing costs without having realized any benefits from the Merger during the period of delay.

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Exelon will also incur transaction fees and costs related to formulating integration plans. Additional unanticipated costs may be incurred in the integration of the two companies businesses. Although Exelon expects that the elimination of costs, as well as the realization of other efficiencies related to the integration of the businesses, will exceed incremental transaction and Merger-related costs over time, this net benefit may not be achieved in the near term, or at all.

Exelon may not realize the expected benefits of the Merger because of integration difficulties and other challenges.

The success of the PHI acquisition will depend, in part, on Exelon s ability to realize all or some of the anticipated benefits from integrating PHI s business with Exelon s existing businesses. The integration process may be complex, costly and time-consuming. The challenges associated with integrating the operations of PHI s business include, among others:

- delay in implementation of our business plan for the combined business;
- unanticipated issues or costs in integrating financial, information technology, communications and other systems;
- possible inconsistencies in standards, controls, procedures and policies, and compensation structures between PHI s structure and our structure;
- unanticipated changes in applicable laws and regulations;
- difficulties in retention of key employees;
- operating risks inherent in PHI s business and our business; and
- unexpected regulatory requirements.

Exelon and PHI will be subject to various uncertainties while the Merger is pending that may adversely affect their ability to attract and retain key employees, and potentially affect the company s financial results.

Uncertainty about the effect of the Merger on employees, suppliers and customers may have an adverse effect on Exelon and/or PHI. These uncertainties may impair Exelon s and/or PHI s ability to attract, retain and motivate key personnel until the Merger is completed and for a period of time thereafter, as employees and prospective employees may experience uncertainty about their future roles with the combined company. In addition, current and prospective Exelon and PHI employees may determine that they do not desire to work for the combined company for a variety of possible reasons.

The Merger may divert attention of management at Exelon and PHI, which could detract from efforts to meet business goals.

The pursuit of the Merger and the preparation for the integration may place a burden on management and internal resources. Any significant diversion of management attention away from ongoing business concerns and any difficulties encountered in the transition and integration process could affect Exelon s and/or PHI s financial results. The process of integrating the operations of PHI may require a disproportionate amount of resources and management attention. Exelon s future operations and cash flows will depend to a significant degree upon Exelon s ability to operate PHI efficiently, achieve the strategic operating objectives for the business and realize cost savings and synergies. Exelon s management team may encounter unforeseen difficulties in managing the integration. In order to successfully integrate PHI, Exelon s management team will need to focus on realizing anticipated synergies and cost savings on a timely basis while maintaining the efficiency of operations. Any substantial diversion of management attention could affect Exelon s ability to achieve operational, financial and strategic objectives.

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We are obligated to complete the Merger whether or not we have obtained the required financing.

Exelon intends to fund the cash consideration in the Merger using a combination of approximately $3.5 billion of debt, up to $1.0 billion in cash from asset sales, and the remainder through issuance of equity (including mandatory convertible securities). See Note 4 Mergers, Acquisitions, and Dispositions and Note 13 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information regarding the merger financing.

The combined company s assets, liabilities or results of operations could be adversely affected by unknown or unexpected events, conditions or actions that might occur at PHI prior to the closing of the Merger.

The PHI assets, liabilities, business, financial condition, cash flows, operating results and prospects to be acquired or assumed by Exelon by reason of the merger could be adversely affected before or after the Merger closing as a result of previously unknown events or conditions occurring or existing before the Merger closing. Adverse changes in PHI s business or operations could occur or arise as a result of actions by PHI, legal or regulatory developments including the emergence or unfavorable resolution of pre-acquisition loss contingencies, deteriorating general business, market, industry or economic conditions, and other factors both within and beyond the control of PHI. A significant decline in the value of PHI assets to be acquired by Exelon or a significant increase in PHI liabilities to be assumed by Exelon could adversely affect the combined company s future business, financial condition, cash flows, operating results and prospects.

Exelon may record goodwill that could become impaired and adversely affect its operating results.

In accordance with GAAP, the Merger will be accounted for as an acquisition of PHI common stock by Exelon and will follow the acquisition method of accounting for business combinations. The assets and liabilities of PHI will be consolidated with those of Exelon. The excess of the purchase price over the fair values of PHI s assets and liabilities, if any, will be recorded as goodwill.

The amount of goodwill, which could be material, will be allocated to the appropriate reporting units of the combined company. Exelon is required to assess goodwill for impairment at least annually by comparing the fair value of reporting units to the carrying value of those reporting units. To the extent the carrying value of any of those reporting units is greater than the fair value, a second step comparing the implied fair value of goodwill to the carrying amount would be required to determine if the goodwill is impaired. Such a potential impairment could result in a material non-cash charge that would have a material impact on Exelon s future operating results and consolidated balance sheet.

Legal proceedings in connection with the Merger, the outcomes of which are uncertain, could delay or prevent the completion of the Merger.

One of the conditions to the closing of the Merger is that no judgment (whether preliminary, temporary or permanent) or other order by any court or other governmental entity shall be in effect that restrains, enjoins or otherwise prohibits or makes illegal the consummation of the Merger.

PHI and its directors have been named as defendants in purported class action lawsuits filed on behalf of named plaintiffs and other public stockholders challenging the proposed Merger and seeking, among other things, to enjoin the defendants from consummating the Merger on the agreed-upon terms. Exelon has been named as a defendant in these lawsuits. Exelon has also been named in a federal court case with similar claims. In September 2014, the parties reached a proposed settlement which is subject to court approval. Final court approval of the proposed settlement is not expected to occur until the second quarter of 2015, at the earliest.

If a plaintiff in these or any other litigation claims that may be filed in the future is successful in obtaining an injunction prohibiting the parties from completing the Merger on the terms contemplated by the Merger Agreement, the injunction may prevent the completion of the Merger in the expected time frame or altogether. If completion of the Merger is prevented or delayed, it could result in substantial costs to Exelon. In addition, Exelon could incur significant costs in connection with the lawsuits, including costs associated with the indemnification of PHI s directors and officers.

Private parties who may believe they are adversely affected by the Merger and individual states may bring legal actions under the antitrust laws in certain circumstances or intervene in regulatory proceedings. Although Exelon and PHI believe the completion of the Merger will not conflict with any antitrust law, there can be no assurance that a challenge to the Merger on antitrust grounds will not be made or, if a challenge is made, what the result will be. Under the Merger Agreement, Exelon and PHI have agreed to use their reasonable best efforts to obtain all regulatory clearances necessary to complete the Merger as promptly as practicable. In addition, in order to complete the Merger, Exelon and PHI may be required to comply with conditions, terms, obligations or restrictions imposed by regulatory agencies and any such conditions, terms, obligations or restrictions may have the effect of delaying completion of the Merger, imposing additional material costs on or materially limiting Exelon s revenues after the completion of the Merger, or otherwise reducing the anticipated benefits from the Merger. In addition, any such conditions, terms, obligations or restrictions could result in the delay or abandonment of the Merger.

The Merger may be completed on terms different from those contained in the Merger Agreement.

Prior to the completion of the Merger, Exelon and PHI may, by their mutual agreement, amend or alter the terms of the Merger Agreement, including with respect to, among other things, the Merger consideration to be received by PHI stockholders or any covenants or agreements with respect to the parties respective operations pending completion of the Merger. In addition, Exelon may choose to waive requirements of the Merger Agreement, including some conditions to closing of the Merger. Any such amendments, alterations or waivers may have negative consequences to Exelon.

Risks Related to the Merger with Constellation

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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Exelon, Generation, ComEd, PECO and BGE

None.

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ITEM 2. PROPERTIES

Generation

The following table describes Generation s interests in net electric generating capacity by station at December 31, 2014:

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	2,317
Peach Bottom	Mid-Atlantic	Delta, PA	2	50	Uranium	Base-load	1,165[f]
Salem	Mid-Atlantic	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	1,005[f]
Calvert Cliffs	Mid-Atlantic	Lusby, MD	2	50.01	Uranium	Base-load	878[f][g]
Three Mile Island	Mid-Atlantic	Middletown, PA	1		Uranium	Base-load	837
Oyster Creek	Mid-Atlantic	Forked River, NJ	1		Uranium	Base-load	625[e]
Conowingo	Mid-Atlantic	Darlington, MD	11		Hydroelectric	Base-load	572
Criterion	Mid-Atlantic	Oakland, MD	28		Wind	Base-load	70
Fourmile	Mid-Atlantic	Garrett County, MD	16		Wind	Base-load	40
Solar Horizons	Mid-Atlantic	Emmitsburg, MD	1		Solar	Base-load	14
Solar New Jersey 2	Mid-Atlantic	Various, NJ	2		Solar	Base-load	9
Solar New Jersey 1	Mid-Atlantic	Various, NJ	4		Solar	Base-load	8
Solar Maryland	Mid-Atlantic	Various, MD	9		Solar	Base-load	7
Solar Federal	Mid-Atlantic	Trenton, NJ	1		Solar	Base-load	4
Solar Maryland 2	Mid-Atlantic	Pocomoke, MD	2		Solar	Base-load	3
Solar New Jersey 3	Mid-Atlantic	Middle Township, NJ	5		Solar	Base-load	1
Muddy Run	Mid-Atlantic	Drumore, PA	8		Hydroelectric	Intermediate	1,070
Eddystone 3, 4	Mid-Atlantic	Eddystone, PA	2		Oil/Gas	Intermediate	760
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	3		Oil/Gas	Peaking	113[h]
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
Total Mid-Atlantic							11,420
Braidwood	Midwest	Braidwood, IL	2		Uranium	Base-load	2,378
LaSalle	Midwest	Seneca, IL	2		Uranium	Base-load	2,327
Byron	Midwest	Byron, IL	2		Uranium	Base-load	2,344
Dresden	Midwest	Morris, IL	2		Uranium	Base-load	1,845
Quad Cities	Midwest	Cordova, IL	2	75	Uranium	Base-load	1,403[f]
Clinton	Midwest	Clinton, IL	1		Uranium	Base-load	1,069
Michigan Wind 2	Midwest	Sanilac Co., MI	50		Wind	Base-load	90

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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
Beebe 1B	Midwest	Gratiot Co., MI	21		Wind	Base-load	50
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)]
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							12,153
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	6		Gas	Intermediate	498
Quail Run	ERCOT	Odessa, TX	6		Gas	Intermediate	488[(i)]
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, MA	2		Solar	Base-load	4
Solar Massachusetts	New England	Various, MA	15		Solar	Base-load	7
Solar Net Metering	New England	Uxbridge, MA	1		Solar	Base-load	2
Solar Connecticut	New England	Various, CT	2		Solar	Base-load	1
Mystic 8, 9	New England	Charlestown, MA	6		Gas	Intermediate	1,418
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							2,218
Solar New York	New York	Bethlehem, NY	1		Solar	Base-load	2
Nine Mile Point	New York	Scriba, NY	2	50.01	Uranium	Base-load	835[(f)(g)]
Ginna	New York	Ontario, NY	1	50.01	Uranium	Base-load	288[(f)(g)]
Total New York							1,125
AVSR	Other	Lancaster, CA	1		Solar	Base-load	242
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	26
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

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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)]
Three Mile Canyon	Other	Boardman, OR	6		Wind	Base-load	10
Solar Arizona	Other	Various, AZ	31		Solar	Base-load	27
Outback Solar	Other	Christmas Valley, OR	1		Solar	Base-load	5
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	Various, CA	37		Solar	Base-load	16
Solar California	Other	Various, CA	4		Solar	Base-load	2
Solar Georgia	Other	Various, GA	10		Solar	Base-load	9
Hillabee	Other	Alexander City, AL	3		Gas	Intermediate	695
Grande 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							1,834
Total							32,753

(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) 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 had a unit-contingent PPA with CENG under which it purchased 85% of the nuclear plant output owned by CENG that was not sold to third parties under the pre-existing PPAs through 2014.
(h) Generation has agreed to retire and cease generation operation at the Riverside 6 unit effective June 1, 2014.
(i) As of December 31, 2014, the assets and liabilities of Quail Run are reported as Assets held for sale and within Other current liabilities on Exelon s and Generation s Consolidated Balance Sheets. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for further information.

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.

In addition to the electric generating stations, Generation has working interests in 9 natural gas and oil exploration and production properties (Upstream) across the United States. Production volumes will vary from year to year due to the timing of individual project start-ups, operational outages, reservoir performance, regulatory changes, asset sales, weather events, price effects and other factors.

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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 Exelon Generation Company, LLC. 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, 2014 were as follows:

Voltage (Volts)	Circuit Miles
765,000	90
345,000	2,656
138,000	2,306

ComEd s electric distribution system includes 35,464 circuit miles of overhead lines and 30,778 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.

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Transmission and Distribution

PECO s high voltage electric transmission lines owned and in service at December 31, 2014 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 8,948 circuit miles of underground lines.

Gas

The following table sets forth PECO s natural gas pipeline miles at December 31, 2014:

	Pipeline Miles
Transmission	30
Distribution	6,792
Service piping	6,128
Total	12,950

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.

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Transmission and Distribution

BGE s high voltage electric transmission lines owned and in service at December 31, 2014 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 9,386 circuit miles of overhead lines and 16,148 circuit miles of underground lines.

Gas

The following table sets forth BGE s natural gas pipeline miles at December 31, 2014:

	Pipeline Miles
Transmission	163
Distribution	7,114
Service piping	6,179
Total	13,456

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.

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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 Note 3 Regulatory Matters and Note 22 Commitments and Contingencies 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.

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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, 2015, there were 859,833,343 shares of common stock outstanding and approximately 123,997 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:

	2014				2013			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 38.93	$ 36.26	$ 37.73	$ 33.94	$ 30.59	$ 32.42	$ 37.80	$ 34.56
Low price	33.07	30.66	33.11	26.45	26.64	29.42	29.84	29.10
Close	37.08	34.09	36.48	33.56	27.39	29.64	30.88	34.48
Dividends	0.310	0.310	0.310	0.310	0.310	0.310	0.310	0.525

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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 2010 through 2014.

This performance chart assumes:

- $100 invested on December 31, 2009 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and
- All dividends are reinvested.

	Value of Investment at December 31,					
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Exelon Corporation	$100	$74.88	$77.99	$53.48	$49.25	$66.68
S&P 500	$100	$139.23	$139.23	$157.89	$204.63	$227.94
S&P Utilities	$100	$107.71	$123.69	$120.09	$130.60	$162.33

Generation

As of January 31, 2015, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2015, there were 127,016,950 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, 2015, in addition to Exelon, there were 297 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

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PECO

As of January 31, 2015, 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, 2015, 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, in connection with the Constellation merger, BGE was 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 and notify the MDPSC that BGE s equity ratio is at least 48% within five business days after dividend payment. 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, 2014, Exelon had retained earnings of $10,910 million, including Generation s undistributed earnings of $3,803 million, ComEd s retained earnings of $851 million consisting of retained earnings appropriated for future dividends of $2,490 million, partially offset by $(1,639) million of unappropriated retained deficits, PECO s retained earnings of $681 million, and BGE s retained earnings of $1,203 million.

The following table sets forth Exelon s quarterly cash dividends per share paid during 2014 and 2013:

	2014				2013			
	4th	3rd	2nd	1st	4th	3rd	2nd	1st
(per share)	Quarter	Quarter	Quarter	Quarter	Quarter	Quarter	Quarter	Quarter
Exelon	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.525

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

	2014				2013			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$ 205	$ 205	$ 205	$ 30	$ 75	$ 76	$ 263	$ 211
ComEd	77	77	77	76	55	55	55	55
PECO	80	80	80	80	83	83	83	83

First Quarter 2015 Dividend. On January 27, 2015, the Exelon Board of Directors declared a first quarter 2015 regular quarterly dividend of $0.31 per share on Exelon s common stock payable on March 10, 2015, to shareholders of record of Exelon at the end of the day on February 13, 2015.

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)	2014 [(a)]	2013	2012 [(b)]	2011	2010
Statement of Operations data:					

Operating revenues	$ 27,429	$ 24,888	$ 23,489	$ 19,063	$ 18,644
Operating income	3,096	3,669	2,373	4,479	4,726
Income from continuing operations	1,820	1,729	1,171	2,499	2,563
Net income	1,820	1,729	1,171	2,499	2,563
Net income attributable to common shareholders	1,623	1,719	1,160	2,495	2,563
Earnings per average common share (diluted):					
Income from continuing operations	$ 1.88	$ 2.00	$ 1.42	$ 3.75	$ 3.87
Net income	$ 1.88	$ 2.00	$ 1.42	$ 3.75	$ 3.87
Dividends per common share	$ 1.24	$ 1.46	$ 2.10	$ 2.10	$ 2.10
Average shares of common stock outstanding diluted	864	860	819	665	663

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(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 financial results include CENG s results of operations on a fully consolidated basis.
(b) 2012 financial results include the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.

(In millions)	2014	2013	December 31, 2012	2011	2010
Balance Sheet data:					
Current assets	$ 12,097	$ 10,137	$ 10,140	$ 5,713	$ 6,398
Property, plant and equipment, net	52,087	47,330	45,186	32,570	29,941
Noncurrent regulatory assets	6,076	5,910	6,497	4,518	4,140
Goodwill	2,672	2,625	2,625	2,625	2,625
Other deferred debits and other assets	13,882	13,922	14,113	9,569	9,136
Total assets	$ 86,814	$ 79,924	$ 78,561	$ 54,995	$ 52,240
Current liabilities	$ 8,762	$ 7,728	$ 7,791	$ 5,134	$ 4,240
Long-term debt, including long-term debt to financing trusts	20,010	18,271	18,346	12,189	12,004
Noncurrent regulatory liabilities	4,550	4,388	3,981	3,627	3,555
Other deferred credits and other liabilities	29,359	26,597	26,626	19,570	18,791
Preferred securities of subsidiary			87	87	87
Noncontrolling interest	1,332	15	106	3	3
BGE preference stock not subject to mandatory redemption	193	193	193		
Shareholders equity	22,608	22,732	21,431	14,385	13,560
Total liabilities and shareholders equity	$ 86,814	$ 79,924	$ 78,561	$ 54,995	$ 52,240

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)	2014 (a)	For the Years Ended December 31, 2013	2012 (b)	2011	2010
Statement of Operations data:					
Operating revenues	$ 17,393	$ 15,630	$ 14,437	$ 10,447	$ 10,025
Operating income	1,176	1,677	1,113	2,875	3,046
Net income	1,019	1,060	558	1,771	1,972
Net income attributable to membership interest	835	1,070	562	1,771	1,972

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 financial results include CENG s results of operations on a fully consolidated basis.
(b) 2012 financial results include the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.

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(In millions)	2014	2013	December 31, 2012	2011	2010
Balance Sheet data:					
Current assets	$ 7,638	$ 6,439	$ 6,211	$ 3,217	$ 3,087
Property, plant and equipment, net	22,945	20,111	19,531	13,475	11,662
Other deferred debits and other assets	14,765	14,682	14,939	10,741	9,785
Total assets	$ 45,348	$ 41,232	$ 40,681	$ 27,433	$ 24,534
Current liabilities	$ 4,459	$ 3,867	$ 4,097	$ 2,144	$ 1,843
Long-term debt	7,652	7,168	7,455	3,674	3,676
Other deferred credits and other liabilities	19,186	17,455	16,464	12,907	11,838
Noncontrolling interest	1,333	17	108	5	5
Member s equity	12,718	12,725	12,557	8,703	7,172
Total liabilities and member s equity	$ 45,348	$ 41,232	$ 40,681	$ 27,433	$ 24,534

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.

(In millions)	2014	For the Years Ended December 31, 2013	2012	2011	2010
Statement of Operations data:					
Operating revenues	$ 4,564	$ 4,464	$ 5,443	$ 6,056	$ 6,204
Operating income	980	954	886	982	1,056
Net income	408	249	379	416	337

(In millions)	2014	2013	December 31, 2012	2011	2010
Balance Sheet data:					
Current assets	$ 1,723	$ 1,540	$ 1,775	$ 2,188	$ 2,151
Property, plant and equipment, net	15,793	14,666	13,826	13,121	12,578
Goodwill	2,625	2,625	2,625	2,625	2,625
Noncurrent regulatory assets	852	933	666	699	947
Other deferred debits and other assets	4,399	4,354	4,013	4,005	3,351
Total assets	$ 25,392	$ 24,118	$ 22,905	$ 22,638	$ 21,652
Current liabilities	$ 1,986	$ 2,048	$ 1,655	$ 2,071	$ 2,134
Long-term debt, including long-term debt to financing trusts	5,904	5,264	5,521	5,421	4,860
Noncurrent regulatory liabilities	3,655	3,512	3,229	3,042	3,137
Other deferred credits and other liabilities	5,940	5,766	5,177	5,067	4,611
Shareholders equity	7,907	7,528	7,323	7,037	6,910
Total liabilities and shareholders equity	$ 25,392	$ 24,118	$ 22,905	$ 22,638	$ 21,652

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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)	**2014**	**2013**	**2012**	**2011**	**2010**
Statement of Operations data:					
Operating revenues	$ 3,094	$ 3,100	$ 3,186	$ 3,720	$ 5,519
Operating income	572	666	623	655	661
Net income	352	395	381	389	324
Net income attributable to common shareholder	352	388	377	385	320

	December 31,				
(In millions)	**2014**	**2013**	**2012**	**2011**	**2010**
Balance Sheet data:					
Current assets	$ 714	$ 906	$ 1,094	$ 1,243	$ 1,670
Property, plant and equipment, net	6,801	6,384	6,078	5,874	5,620
Noncurrent regulatory assets	1,529	1,448	1,378	1,216	968
Other deferred debits and other assets	899	879	803	823	727
Total assets	$ 9,943	$ 9,617	$ 9,353	$ 9,156	$ 8,985
Current liabilities	$ 653	$ 891	$ 1,158	$ 1,145	$ 1,163
Long-term debt, including long-term debt to financing trusts	2,430	2,131	1,831	1,781	2,156
Noncurrent regulatory liabilities	657	629	538	585	418
Other deferred credits and other liabilities	3,082	2,901	2,757	2,620	2,278
Preferred securities			87	87	87
Shareholders equity	3,121	3,065	2,982	2,938	2,883
Total liabilities and shareholders equity	$ 9,943	$ 9,617	$ 9,353	$ 9,156	$ 8,985

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.

	For the Years Ended December 31,				
(In millions)	**2014**	**2013**	**2012**	**2011**	**2010**
Statement of Operations data:					
Operating revenues	$ 3,165	$ 3,065	$ 2,735	$ 3,068	$ 3,541
Operating income	439	449	132	314	350
Net income	211	210	4	136	147

Net income (loss) attributable to common shareholder	198	197	(9)	123	134

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(In millions)	2014	2013	December 31, 2012 [a]	2011 [a]	2010 [a]
Balance Sheet data:					
Current assets	$ 957	$ 1,011	$ 980	$ 969	$ 1,012
Property, plant and equipment, net	6,204	5,864	5,498	5,132	4,754
Noncurrent regulatory assets	510	524	522	551	566
Other deferred debits and other assets	407	462	506	551	545
Total assets	$ 8,078	$ 7,861	$ 7,506	$ 7,203	$ 6,877
Current liabilities	$ 846	$ 827	$ 980	$ 734	$ 728
Long-term debt, including long-term debt to financing trusts and variable interest entities	2,125	2,199	1,969	2,186	2,060
Noncurrent regulatory liabilities	200	204	214	201	192
Other deferred credits and other liabilities	2,154	2,076	1,985	1,781	1,634
Preference stock not subject to mandatory redemption	190	190	190	190	190
Shareholders equity	2,563	2,365	2,168	2,111	2,073
Total liabilities and shareholders equity	$ 8,078	$ 7,861	$ 7,506	$ 7,203	$ 6,877

(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 the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities (Upstream).

As a result of the Constellation merger, Generation owns a 50.01% interest in CENG. During 2014, Generation assumed the operating licenses and corresponding operational control of CENG s nuclear fleet. As a result, Exelon and Generation fully consolidated CENG s financial position and results of operations into their businesses beginning on April 1, 2014.

ComEd, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers 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 electricity 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 natural gas and the provision of electricity distribution and transmission and gas 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 Segment Information 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.

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Financial Results. The following consolidated financial results reflect the results of Exelon for the year ended December 31, 2014 compared to the same period in 2013. The 2014 financial results only include the operations of CENG on a fully consolidated basis from the date Generation assumed operational control, April 1, 2014, through December 31, 2014. All amounts presented below are before the impact of income taxes, except as noted.

	The Years Ended December 31,							Favorable
	2014						2013	(Unfavorable)
	Generation [a]	ComEd	PECO	BGE	Other	Exelon	Exelon	Variance
Operating revenues	$ 17,393	$ 4,564	$ 3,094	$ 3,165	$ (787)	$ 27,429	$ 24,888	$ 2,541
Purchased power and fuel expense	9,925	1,177	1,261	1,417	(777)	13,003	10,724	(2,279)
Revenue net of purchased power and fuel expense [b]	7,468	3,387	1,833	1,748	(10)	14,426	14,164	262
Other operating expenses								
Operating and maintenance	5,566	1,429	866	717	(10)	8,568	7,270	(1,298)
Depreciation and amortization	967	687	236	371	53	2,314	2,153	(161)
Taxes other than income	465	293	159	221	16	1,154	1,095	(59)
Total other operating expenses	6,998	2,409	1,261	1,309	59	12,036	10,518	(1,518)
Equity in (losses) earnings of unconsolidated affiliates	(20)					(20)	10	(30)
Gain (loss) on sales of assets	437	2			(2)	437	13	424
Gain on consolidation and acquisition of businesses	289					289		289
Operating income (loss)	1,176	980	572	439	(71)	3,096	3,669	(573)
Other income and (deductions)								
Interest expense, net	(356)	(321)	(113)	(106)	(169)	(1,065)	(1,356)	291
Other, net	406	17	7	18	7	455	460	(5)
Total other income and (deductions)	50	(304)	(106)	(88)	(162)	(610)	(896)	286
Income (loss) before income taxes	1,226	676	466	351	(233)	2,486	2,773	(287)
Income taxes	207	268	114	140	(63)	666	1,044	378
Net income (loss)	1,019	408	352	211	(170)	1,820	1,729	91
Net income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	184			13		197	10	(187)
Net income (loss) attributable to common shareholders	$ 835	$ 408	$ 352	$ 198	$ (170)	$ 1,623	$ 1,719	$ (96)

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 financial results include CENG s results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.

(b) 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 attributable to common shareholders was $1,623 million for the year ended December 31, 2014 as compared to $1,719 million for the year ended December 31, 2013, and diluted earnings per average common share were $1.88 for the year ended December 31, 2014 as compared to $2.00 for the year ended December 31, 2013.

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Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $262 million as compared to 2013. The year-over-year increase reflects the inclusion of CENG s results beginning April 1, 2014 and was primarily due to the following favorable factors:

Increase of $815 million at Generation primarily due to the inclusion of CENG s results beginning April 1, 2014 through December 31, 2014, a decrease in fuel costs related to the cancellation of DOE spent nuclear fuel disposal fees, increased capacity prices related to the Reliability Pricing Model (RPM) for the PJM Interconnection, LLC (PJM) market, and favorable portfolio management activities in the New England and South regions; partially offset by higher procurement costs for replacement power related to the extreme cold weather in the first quarter of 2014 and lower realized energy prices related to executing Generation s ratable hedging strategy;

Increase of $365 million at Generation related to the reduction in amortization of in-the-money energy contracts recorded at fair value at the Constellation merger date and an increase related to the amortization of out-of-the money energy contracts recorded at fair value upon the consolidation of CENG;

Increase of $30 million at ComEd primarily reflecting higher transmission revenue due to increased capital investment and an increase of $93 million as a result of increased cost recovery associated with energy efficiency programs and uncollectible accounts expense (both offset below in operating and maintenance expense);

Increase of $33 million at PECO primarily due to increased recovery from regulatory programs (offset below primarily in operating and maintenance expense); and

Increase of $104 million at BGE primarily due to increased distribution revenue as a result of the 2013 and 2014 electric and natural gas distribution rate case orders issued by the Maryland PSC, increased cost recovery for energy efficiency and demand response programs (offset below in depreciation and amortization expense), and increased transmission revenue pursuant to increased rates effective June 2014.

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

Decrease of $1,095 million at Generation due to mark-to-market losses of $591 million in 2014 from economic hedging activities compared to $504 million in mark-to-market gains in 2013.

Decrease of $16 million at ComEd due to unfavorable weather in the ComEd service territory.

Operating and maintenance expense increased by $1,298 million as compared to 2013 primarily due to the following unfavorable factors:

Increase in Generation s labor, contracting and materials costs of $361 million primarily due to the inclusion of CENG s results from April 1, 2014 through December 31, 2014, an increase of $44 million resulting from expenses recorded for a Constellation merger commitment, an increase of $54 million as a result of an increase in the number of planned nuclear refueling outage days at Generation, primarily related to the inclusion of CENG s plants beginning April 1, 2014, and an increase of $16 million in the reserve for future asbestos-related bodily injury claims;

Increase in labor, contracting and materials costs of $56 million at ComEd associated with EIMA smart meter projects and $22 million at BGE due to increased maintenance activities;

Increase in Generation s accretion expense of $78 million primarily due to the inclusion of CENG s results from April 1, 2014 through December 31, 2014;

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Long-lived asset impairments at Generation of $663 million in 2014 compared to $157 million in 2013.

Increased storm costs at PECO and BGE of $100 million and $21 million, respectively;

Increased spending on energy and efficiency programs and increased uncollectible accounts expense at ComEd of $93 million; and

Increased uncollectible accounts expense at BGE of $17 million.

The year-over-year increase in operating and maintenance expense was partially offset by the following favorable factor:

A reduction in pension and non-pension postretirement benefits expense of $178 million primarily at Exelon, Generation, and ComEd, resulting from plan design changes for certain OPEB plans and the favorable impact of higher actuarially assumed pension and OPEB discount rates for 2014, partially offset by the inclusion of CENG s pension and non-pension postretirement benefits expense from April 1, 2014 through December 31, 2014.

Depreciation and amortization expense increased by $161 million primarily as a result of the inclusion of CENG s results from April 1, 2014 through December 31, 2014, increased depreciation expense across the operating companies for ongoing capital expenditures, and higher regulatory asset amortization related to energy efficiency and demand response expenditures.

Exelon recorded $437 million at Generation as a result of gains recorded on the sales of ownership interest in certain generating stations in 2014.

Exelon recorded a $261 million gain upon consolidation of CENG resulting from the difference in fair value of CENG s net assets as of April 1, 2014, and the equity method investment previously recorded on Generation s and Exelon s books and the settlement of pre-existing transactions between Generation and CENG. Additionally, Exelon recorded a $28 million bargain-purchase gain related to the Integrys acquisition.

Interest expense decreased by $291 million primarily as a result of a decrease in 2014 given ComEd s 2013 remeasurement of Exelon s like-kind exchange tax positions, offset at Exelon by an increase in 2014 related to financing activities associated with the pending PHI merger.

Other, net increased by $5 million primarily at Generation as a result of favorable settlements in 2014 of certain income tax positions on Constellation s pre-acquisition 2009-2012 tax returns and the change in realized and unrealized gains and losses on NDT funds.

Exelon s effective income tax rates for the years ended December 31, 2014 and 2013 were 26.8% and 37.6%, 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.

For further detail regarding the financial results for the years ended December 31, 2014 and 2013, 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, 2014 were $2,068 million, or $2.39 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,149 million, or $2.50 per diluted share, for the same period in 2013. In addition to net income,

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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 attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the year ended December 31, 2014 as compared to 2013:

	For the years ended December 31,			
	2014		2013	
(All amounts after tax; in millions, except per share amounts)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 1,623	$ 1.88	$ 1,719	$ 2.00
Mark-to-Market Impact of Economic Hedging Activities [(a)]	363	0.42	(310)	(0.35)
Unrealized Gains Related to NDT Fund Investments [(b)]	(86)	(0.10)	(78)	(0.09)
Plant Retirements and Divestitures [(c)]	(245)	(0.28)	(13)	(0.02)
Asset Retirement Obligation [(d)]	(13)	(0.02)	7	0.01
Merger and Integration Costs [(e)]	185	0.21	87	0.08
Amortization of Commodity Contract Intangibles [(f)]	64	0.07	347	0.41
Reassessment of State Deferred Income Taxes [(g)]	(27)	(0.03)	4	
Long-Lived Asset Impairments [(h)]	435	0.50	110	0.14
Bargain-Purchase Gain on Integrys acquisition [(i)]	(28)	(0.03)		
Gain on CENG Integration [(j)]	(159)	(0.18)		
Tax Settlements [(k)]	(106)	(0.12)		
CENG Non-Controlling Interest [(l)]	62	0.07		
Remeasurement of Like-Kind Exchange Tax Position [(m)]			267	0.31
Midwest Generation Bankruptcy Charges [(n)]			16	0.02
Amortization of the Fair Value of Certain Debt [(o)]			(7)	(0.01)
Adjusted (non-GAAP) Operating Earnings	$ 2,068	$ 2.39	$ 2,149	$ 2.50

(a) Reflects the impact of losses (gains) for the years ended December 31, 2014 and December 31, 2013 (net of taxes of $232 million and ($201) million, respectively) on Generation s economic hedging activities. 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, 2014 and December 31, 2013 (net of taxes of $(77) million and $(144) million, respectively) on Generation s NDT fund investments for Non-Regulatory Agreement Units. See Note 15 Asset Retirement Obligations 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 sales of Generation s ownership interests in generating stations for the years ended December 31, 2014 and December 31, 2013 (net of taxes of $(163) million and ($4) million, respectively).

(d) Reflects the impacts of a decrease in Generation s decommissioning obligation for the year ended December 31, 2014 (net of taxes of $(4) million). Reflects the impacts 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).

(e) Reflects certain costs incurred for the years ended December 31, 2014 and December 31, 2013 (net of taxes of $84 million and $33 million, respectively) including professional fees, employee-related expenses, integration activities, upfront credit facilities, merger commitments, and certain pre-acquisition contingencies, if and when applicable to the Constellation merger in 2013 and the Constellation merger, CENG integration, acquisition of Integrys Energy Services, Inc. (Integrys) and pending PHI acquisition in 2014.
(f) Reflects the non-cash impact for the years ended December 31, 2014 and December 31, 2013 (net of taxes of $68 million and $219 million, respectively) of the amortization of intangibles assets, net, related to commodity contracts recorded at fair value at the 2012 Constellation merger date, the 2014 CENG integration date, and the 2014 Integrys acquisition date.
(g) Reflects the non-cash impacts of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment.
(h) In 2014, reflects charges to earnings related to the impairments of certain generating assets held for sale, Upstream assets, and wind generating assets (net of taxes of $250 million). In 2013, reflects a charge to earnings primarily related to the cancellation of previously capitalized nuclear uprate projects and the impairment of certain wind generating assets (net of taxes of $69 million).
(i) Reflects the excess of the fair value of assets and liabilities acquired over the purchase price for the Integrys acquisition (net of taxes of $(16) million) on November 1, 2014.
(j) Reflects the non-cash gain recorded upon consolidation of CENG in accordance with the execution of the NOSA on April 1, 2014 (net of taxes of $(102) million).
(k) Reflects a benefit related to the favorable settlement in 2014 of certain income tax positions on Constellation s pre-acquisition 2009-2012 tax returns.
(l) Pursuant to the April 1, 2014 consolidation, represents adjustments to account for the CENG interest not owned by Generation, where applicable.
(m) For 2013, reflects a non-cash charge to earnings (net of taxes of $102 million) resulting from the remeasurement of a like-kind exchange tax position taken on ComEd s 1999 sale of fossil generating assets. See Note 14 Income Taxes of the Combined Notes to the Consolidated Financial Statements for additional information.
(n) Reflects costs incurred in 2013 to establish estimated liabilities (net of taxes of $10 million) 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.
(o) Reflects the 2013 non-cash amortization of certain debt (net of taxes of ($5) million) recorded at fair value at the Constellation merger date which was retired in the second quarter of 2013. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information.

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Merger and Acquisition Costs

As discussed above, Exelon has incurred and will continue to incur costs associated with the Integrys and PHI acquisitions including employee-related expenses (e.g. severance, retirement, relocation and retention bonuses), financing costs, integration initiatives, and certain pre-acquisition contingencies.

For the year ended December 31, 2014, expense has been recognized for costs incurred to achieve the Constellation merger, CENG integration, Integrys acquisition and proposed PHI acquisition as follows:

	Pre-tax Expense Twelve Months Ended December 31, 2014				
Merger Integration and Acquisition Costs:	**Generation**	**ComEd**	**PECO**	**BGE**	**Exelon**
Financing [a]	$	$	$	$	$ 131
Regulatory Commitments [b]	44				44
Transaction [c]					26
Employee-Related [d]	5				5
Other [e]	56	4	2	2	65
Total	$ 105	$ 4	$ 2	$ 2	$ 271

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

(a) Reflects costs incurred at Exelon related to the financing of the PHI merger, including upfront credit facility fees.
(b) Reflects costs incurred at Generation for a Constellation merger commitment.
(c) 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 transactions.
(d) Costs primarily for employee severance, pension and OPEB expense and retention bonuses. ComEd established regulatory assets of $2 million for the year ended December 31, 2013. The majority of these costs are expected to be recovered over a five-year period. These costs are not included in the table above.
(e) Costs to integrate CENG and Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. For the year ended December 31, 2014, also includes professional fees primarily related to integration for the proposed PHI acquisition. ComEd and BGE established regulatory assets of $9 million and $12 million, respectively, for the year ended December 31, 2013, for certain other merger and integration costs, which are not included in the table above.

As of December 31, 2014, Exelon projects incurring total additional PHI acquisition and integration related expenses of $650 million, of which approximately $100 million is expected to be capitalized to property, plant and equipment excluding the direct investment Exelon and PHI have proposed to the PHI utilities respective customers.

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 estimate 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 was contingent upon the developer obtaining all required approvals, permits and financing for the construction of a building in Baltimore, Maryland. The operating lease became effective during the second quarter of 2014 when these outstanding contingencies were met by the developer. The building is expected to be ready for occupancy in approximately 2 years. See Note 22 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information related to the lease commitments.

Exelon s Strategy and Outlook for 2015 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. Exelon s strategy is to leverage its integrated business model to create value and diversify its business. Exelon s competitive and regulated businesses feature a mix of attributes that, when combined, offer shareholders and customers a unique value proposition:

- Generation s competitive businesses provide commodity exposure and a platform to diversify into adjacent markets, while providing residual dividend support.
- Exelon s utilities provide a foundation for stable earnings and dividend support, which translates to a stable currency in our stock.

Exelon believes its strategy provides a platform for optimal success in an energy industry experiencing fundamental and sweeping change. While enhancing Exelon s core value, it enables it to take advantage of a myriad of opportunities, rather than focusing on any one segment of the energy industry value chain.

Generation s competitive businesses create value for customers by providing innovative solutions and reliable, clean and affordable energy. 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 Generation 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. The Exelon utilities only invest in rate base where it provides a net benefit to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. The Exelon utilities make these investments prudently and at the lowest reasonable cost to customers. 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 $16 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.

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Various market, financial, and other factors could affect the Registrants success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues. See ITEM 1A. RISK FACTORS for additional information regarding market and financial factors.

Proposed Merger with Pepco Holdings, Inc. (Exelon)

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Under the Merger Agreement, PHI s shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. Exelon intends to fund the all-cash transaction using a combination of approximately $3.5 billion of debt, up to $1 billion cash from asset sales primarily at Generation, and the remainder through issuance of equity (including mandatory convertible securities). In addition, Exelon entered into a 364-day $7.2 billion senior unsecured bridge credit facility to support the contemplated transaction and provide flexibility for timing of permanent financing, which has subsequently been reduced to $3.2 billion as a result of execution of the debt and equity security issuances and the net after-tax cash proceeds from generating asset divestitures during the second half of 2014. See Note 4 Mergers, Acquisitions, and Divestitures, Note 13 Debt and Credit Agreements, and Note 19 Common Stock of the Combined Notes to Consolidated Financial Statements for further information related to these transactions. In connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased $126 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities in PHI as of December 31, 2014, with additional investments of $18 million to be made quarterly up to a maximum aggregate investment of $180 million. As part of the applications for approval of the merger, Exelon and PHI proposed a package of benefits to the PHI utilities respective customers, providing for direct investment of more than $100 million with the actual amount and timing of any related payments dependent upon settlement discussions in merger regulatory approval proceedings and the terms of regulatory orders approving the merger.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBPU) and the FERC have approved the merger of PHI and Exelon. The Federal Communications Commission has also approved the transfer of certain PHI communications licenses. On February 11, 2015, the NJBPU approved the proposed merger and the previously filed settlement signed and filed by Exelon, PHI, Atlantic City Electric (ACE), NJBPU staff, and the Independent Energy Coalition. The settlement provides a package of benefits to ACE customers and the state of New Jersey. This package of benefits includes the establishment of customer rate credit programs, with an aggregate value of $62 million for ACE customers and energy efficiency programs that will provide savings for ACE customers of $15 million.

Completion of the transaction also remains conditioned upon approval by the Public Services Commissions of the District of Columbia, Delaware and Maryland. Procedural schedules have been set in these commission proceedings and final approval decisions are expected in the first half of 2015.

On October 9, 2014, PHI and Exelon each received a request for additional information from the DOJ. The request had the effect of extending the DOJ review period until 30 days after PHI and Exelon each has certified that it has substantially complied with the request. On November 21, 2014, Exelon and PHI each certified that it had substantially complied with the request. Accordingly, the HSR Act waiting period expired on December 22, 2014, and the HSR Act no longer precludes completion of the merger. Although the DOJ allowed the waiting period under the HSR Act to expire without taking any action with respect to the merger, the DOJ has not advised Exelon or PHI that it has concluded its investigation. Exelon and PHI will continue to work cooperatively with the DOJ regarding the proposed merger.

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Exelon and PHI continue to expect to complete the merger in the second or third quarter of 2015.

Through December 31, 2014, Exelon has incurred approximately $179 million of expense associated with the proposed merger, including $48 million related to acquisition and integration costs and $131 million of costs incurred to finance the transaction. The Merger Agreement also provides for termination rights for both parties. Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from $259 million to $293 million plus certain expenses. If the transaction does not close due to a regulatory failure, Exelon may be required to pay PHI a termination fee equal to the amount of purchased nonvoting preferred securities of PHI described above, as a result of PHI redeeming the outstanding nonvoting preferred securities for no consideration other than the nominal par value of the stock.

Exelon has listed various potential risks relating to the pending merger with PHI (see Item 1A. Risk Factors), including difficulties that may be encountered in satisfying the conditions to completion of the merger and the potential for developments that might have an adverse effect on Exelon and the ability to realize the expected benefits of the merger. Exelon is taking steps to manage these risks and expects that the merger can be completed on a basis favorable to the company s shareholders and customers. Accordingly, Exelon anticipates closing the transaction in the second or third quarter of 2015. Refer to Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the merger transaction.

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. Forward natural gas prices have declined significantly over the last several years; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Capacity Market Changes in PJM. In the wake of the January 2014 Polar Vortex that blanketed much of the Eastern and Midwestern United States, it became clear that while a major outage event was narrowly avoided, resources in PJM were not providing the level of reliability expected by customers. To address this disconnect, on December 12, 2014, PJM filed at FERC a proposal to make significant changes to its current capacity market construct, the Reliability Pricing Model (RPM). PJM s proposed changes generally seek to improve resource performance and reliability largely by limiting the excuses for non-performance and by increasing the penalties for performance failures. To cover capital and other costs and risks that suppliers would incur to meet these higher reliability standards, suppliers would be allowed to include adders for such costs as well as risk premiums in their capacity market offers. While offers are expected to put upward pressure on capacity clearing prices, operational improvements made as a result of PJM s proposal are expected to improve reliability, to reduce energy production costs as a result of more efficient operations and to reduce the need for out of market energy payments to suppliers. Exelon participated actively in PJM s stakeholder process through which PJM developed the proposal and is also actively participating in the FERC proceeding including filing comments. PJM asked for a FERC order approving the proposal by April 1, 2015 so PJM can implement the proposal prior to its next capacity auction in May 2015. However, it is not clear when or how the FERC will respond to PJM s proposal or, if it responds within PJM s timeframe, whether FERC will require changes.

Subsidized Generation. The rate of expansion of subsidized generation, including 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.

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Various states have attempted to implement or propose 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 in to law in January 2011, the Long Term Capacity Pilot Program Act (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 the price eligible 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 mandated 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 have challenged the constitutionality and other aspects of the New Jersey legislation and the actions taken by the MDPCS in state and federal courts. Ultimately, the Exelon parties prevailed in obtaining orders from the U.S. Court of Appeals for the Third Circuit and the U.S. Court of Appeals for the Fourth Circuit effectively undoing the actions taken by the New Jersey legislature and the MDPSC respectively. The matter has been appealed to the U.S. Supreme Court, and while the Court of Appeals decisions are helpful, there remains risk the Supreme Court will overrule the lower Courts.

As required under their contracts, generator developers who were selected in the New Jersey and Maryland programs (including CPV) offered and cleared in PJM s capacity market auctions held in May 2012, 2013, and 2014. In addition, CPV has announced its intention to move forward with construction of its New Jersey and Maryland plants, 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 court decisions in New Jersey and Maryland are positive developments, continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR) for future capacity auctions, 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. Exelon continues to monitor developments and participate in stakeholder and other processes to ensure that similar state subsidies are not developed. In addition, Exelon remains active in advocating for competitive markets, while opposing policies that require taxpayers and/ 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.

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

Energy Demand. Modest economic growth partially offset by energy efficiency initiatives is resulting in positive growth for electricity for ComEd and PECO, and no projected growth for electricity for BGE. ComEd, PECO and BGE are projecting load volumes to increase by 0.4%, 0.8% and (0.2)%, respectively, in 2015 compared 2014.

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. The market experienced high price volatility in the first quarter of 2014 which contributed to bankruptcies and consolidations within the industry during the year. However, forward natural gas and power prices are expected to remain low and thus we expect retail competitors to stay aggressive in their pursuit of market share, and that wholesale generators (including Generation) will continue to use their retail operations to hedge generation output.

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 second quarter 2014 dividend of $0.31 per share on Exelon s common stock. The second quarter dividend was paid on June 10, 2014 to shareholders of record on May 16, 2014. All future quarterly dividends require approval by Exelon s board of directors.

Exelon s board of directors declared the third quarter 2014 dividend of $0.31 per share on Exelon s common stock. The third quarter dividend was paid on September 10, 2014 to shareholders of record on August 15, 2014.

Exelon s board of directors declared the fourth quarter 2014 dividend of $0.31 per share on Exelon s common stock. The fourth quarter dividend was paid on December 10, 2014 to shareholders of record on November 14, 2014.

Exelon s board of directors declared the first quarter 2015 dividend of $0.31 per share on Exelon s common stock. The first quarter dividend will be paid on March 10, 2015, to shareholders of record on February 13, 2015.

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. This strategy has not changed as a result of recent and pending asset divestitures. 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, 2014, the percentage of expected generation hedged for the major reportable segments was 93%-96%, 61%-64% and 31%-34% for 2015, 2016, and 2017 respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation (which reflects the divestiture impact of Quail Run). Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, such as wholesale and retail sales of power, options and swaps. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well. See Note 4 Mergers, Acquisition and Dispositions for more detail regarding the divestitures.

Generation procures 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 50% of Generation s uranium concentrate requirements from 2015 through 2019 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 commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Growth Opportunities

With an emphasis on innovation and entrepreneurship, Exelon is currently pursuing growth in both the utility and competitive energy businesses. Identifying and capitalizing on emerging trends and technologies, Exelon plans to invest in new innovative technologies to compete with a new breed of energy players, leverage new technologies to create new or expand existing businesses, and improve productivity and efficiencies within our existing businesses. Management continually evaluates growth opportunities aligned with Exelon s businesses, assets and markets, leveraging Exelon s expertise in those areas.

Competitive Energy Businesses

Generation continues to pursue growth in its existing businesses and markets and further diversification across the competitive energy value chain.

Leveraging its competencies,

Generation s 2014 acquisition of Integrys allows Generation to expand its retail footprint further in an industry sector that continues to mature and consolidate and provides hedging and diversification benefits to its existing portfolio.

Generation continues to pursue investment opportunities in renewables, in its nuclear uprate program and in the development of natural gas generation plants that is supported by the trend of increasing natural gas supply.

Investing in business diversification to position the company for the future,

Generation has launched a business in competitive distributed generation that capitalizes on the push toward a decentralized system.

Generation is also making investments across the natural gas value chain throughout North America, focusing initially on expansion of the existing Upstream and wholesale gas businesses, as well as entry into liquefied natural gas.

Regulated Energy Businesses

The proposed acquisition of PHI provides an opportunity to accelerate Exelon s regulated growth and provide stable cash flows, earnings accretion, and dividend stability. Additionally, ComEd, PECO and BGE anticipate making significant future investments in infrastructure modernization, including smart meter and smart grid initiatives, storm hardening, and advanced reliability technologies. Upon obtaining various approvals, ComEd also plans to invest approximately $280 million to construct the Grand Prairie Gateway Transmission Line in Illinois alleviating identified congestion and enhancing reliability. ComEd, PECO and BGE invest in rate base where it provides a net benefit to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. These investments are made prudently and at the lowest reasonable cost to customers.

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

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 OPEB obligations and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). 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 $0.5 billion. See Liquidity and Capital Resources Credit Matters Exelon Credit Facilities below.

Exposure to Worldwide Financial Markets. Exelon has exposure to worldwide financial markets including European banks. 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, 2014, approximately 29%, or $2.5 billion, of the Registrants aggregate total commitments were with European banks, excluding the unsecured bridge facility to provide financing for the proposed PHI acquisition. The credit facilities include $8.5 billion in aggregate total commitments of which $7.3 billion was available as of December 31, 2014, due to outstanding letters of credit. There were no borrowings under the Registrants credit facilities as of December 31, 2014. See Note 13 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

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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., NOx, SO2 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 tightened ozone NAAQS, to be finalized in late 2015, proposed for public comment in December 2014. These recently finalized or proposed 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. Numerous entities challenged the CSAPR in the D.C. Circuit Court. On August 21, 2012, the D.C. Circuit Court of Appeals 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. On April 29, 2014, the U.S. Supreme Court reversed the D.C. Circuit Court decision and upheld CSAPR, and remanded the case to the D.C. Circuit Court to resolve the remaining implementation issues On November 21, 2014, the U.S. EPA issued an Interim Final Rule in which the Agency announced that it was tolling the effective dates for the CSAPR. The first phase of the CSAPR program started on January 1, 2015, with the second phase starting January 1, 2017. Also released on November 21, 2014, was a Notice of Data Availability under which the Agency proposed CSAPR allowance allocations to generating units for the first five years of the program, 2015-2020; these were identical to those previously identified in prior final rules related to the CSAPR.

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. 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 challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. On April 15, 2014, the D.C. Circuit Court issued an opinion upholding MATS in its entirety.

In November 2014, the U.S. Supreme Court granted a petition for review of the MATS Rule filed by 20 states and a coalition of coal-fired electric generators. The U.S. Supreme Court announced that it will review a single, yet critical, aspect of the MATS Rule whether the U.S. EPA properly considered compliance costs (e.g., pollution control capital expenditures and on-going operations and maintenance expense) in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric utilities. If the Court finds that the U.S. EPA acted unreasonably, then implementation of the rule would be delayed until the U.S. EPA corrects any deficiencies. It is likely that the U.S. Supreme Court will issue a decision sometime in 2015. Exelon has been participating in the case as an intervenor in support of the rule.

The U.S. EPA continued its regular, periodic review of the NAAQS standards. On November 25, 2014, the Agency proposed, for public comment, the establishment of a revised primary ozone standard in the range of 65-70 parts per billion (ppb) 8-hour average, a reduction from the 2008 ozone standard level of 75 ppb 8-hour average standard. The Agency is also requesting public comment on levels as low as 60 ppb 8-hour average. In its proposal, the Agency is also proposing to extend the ozone season on a state-by-state basis from its current May-September five-month period to include months before, and after, the traditional ozone season, depending on air quality monitoring data. Most CSAPR states are proposed to be subjected to a March to October ozone season. In its proposed rule, the Agency also elected to set the secondary standard at the same level and form as the primary standard. The Agency is expected to issue its final ozone NAAQS revision in October 2015. 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.

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 SO2 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 March 25, 2015. With regard to Texas and Maryland, no nonattainment areas were identified in EPA s final designation rule. With regard to Illinois and Pennsylvania, several counties, or portions of counties, in each state were identified as nonattainment. Since the 2010 one-hour SO2 standard was finalized, EPA has issued a series of guidance documents, and proposed a Data Requirement Rule that will be finalized in the summer of 2015 related to requirements for states related to the application of air quality monitoring and modeling in state implementation plans. Nonattainment county compliance with the one-hour SO2 standard is required by March 25, 2018. While significant SO2 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 SO2 emissions in support of attainment of the one hour SO2 standard.

The cumulative impact of these air regulations could be to require fossil fuel-fired power plant operators to expend significant capital to install pollution control technologies, including wet flue gas desulfurization technology for SO2 and acid gases, and selective catalytic reduction technology for NOx.

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In addition, as of December 31, 2014, Exelon had a $361 million net investment in coal-fired plants in Georgia subject to long-term leases extending through 2028 and 2030. 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 impairments recorded in the second quarter of 2013 and 2014, 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.

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. 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 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 U.S. EPA 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. The Climate Action Plan also required the U.S. EPA 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. That proposed rule was published in the Federal Register on June 16, 2014. The proposed rule establishes emission reduction targets for each state and provides flexibility for each state to determine how to achieve its required reductions, including heat rate improvements at coal-fired power plants, fuel switching from coal to gas, renewable generation and new nuclear facilities, demand side energy efficiency, and the use of market-based instruments. 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 October 14, 2014, the U.S. EPA s final Section 316(b) rule became effective. The rule requires that a series of studies and analyses be performed at each facility to determine the best technology available, followed by an implementation period. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director.

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Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, the impact of compliance with the final rule is unknown. Should a state permitting director determine that a facility is required to install cooling towers to comply with the rule, that facility s economic viability would be called into question. However, the likely impact of the rule has been significantly decreased since the final rule does not mandate cooling towers as a national standard, and the state permitting director is required to apply a cost-benefit test and take into consideration site-specific factors.

Hazardous and Solid Waste. On December 19, 2014, the U.S. EPA issued the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants, including the classification of CCR as non-hazardous waste under RCRA. The EPA ruling is effective 180 days after publication in the Federal Register, which is anticipated in early 2015. Under the regulation, CCR will continue to be regulated by most states subject to coordination with the federal regulations. Generation has previously recorded reserves consistent with state regulation for its owned coal ash sites, and as such, the regulation is not expected to impact Exelon s and Generation s financial results. Generation is evaluating what, if any, incremental costs will be incurred for coal ash disposal sites formerly owned by Generation that have not yet been closed by their current owners. At this time, however, Generation does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted for these former sites under the new federal regulations. For these reasons, Generation is unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations, and as a result no new liability has been recorded as of December 31, 2014.

See Note 22 Commitments and Contingencies 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

NRC Task Force Insights from the Fukushima Daiichi Accident. In July 2011, an NRC Task Force formed in the aftermath of the March 11, 2011, 9.0 magnitude earthquake and ensuing tsunami, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, issued a report of its review of the accident, including tiered 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. 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 Generation, net of expected co-owner reimbursements, for the period from 2015 through 2019 is expected to be between approximately $325 million and $350 million of capital (including approximately $75 million for the CENG plants) and $75 million of operating expense (including approximately $25 million for the CENG plants). 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 thirteen Mark 1 and II units (including two CENG units) for the installation of filters on 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 and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Executive Overview of the Exelon 2014 Form 10-K, for additional information.

Financial Reform Legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was enacted in July 2010. The part of the Act that applies to Exelon is Title VII, which is known as the Dodd-Frank Wall Street Transparency and Accountability Act (Dodd-Frank). Dodd-Frank requires the creation of a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing for certain categories of Swaps, incentives to shift Swap activity to exchange trading, margin and capital requirements, and other obligations designed to promote transparency. For non security-based Swaps including commodity Swaps, Dodd-Frank empowers the Commodity Futures Trading Commission (CFTC) to promulgate regulations implementing the law s objectives. The primary aim of Dodd-Frank is to regulate the key intermediaries in the Swaps market, which entities are either swap dealers (SDs), major swap participants (MSPs), and certain other financial entities, but the law also applies to a lesser degree to end-users of Swaps. On January 12, 2015, President Obama signed into law a bill that exempts from margin requirements Swaps used by end-users to hedge or mitigate commercial risk. Moreover, the CFTC s Dodd-Frank regulations preserve the ability of end users in the energy industry to hedge their risks using Swaps without being subject to mandatory clearing, and excepts or exempts end-users from many of the other substantive regulations. Accordingly, as an end-user, Generation is conducting its commercial business in a manner that does not require registration with the CFTC as an SD or MSP. Generation does not anticipate transacting in the future in a manner in which it would become a SD or MSP.

There are, however, some rulemakings that have not yet been finalized, including the capital and margin rules for (non-cleared) Swaps. Generation does not expect these rules to directly impact its collateral requirements. However, depending on the substance of these final rules in addition to certain international regulatory requirements still under development and that are similar to Dodd-Frank, Generation s Swap counterparties could be subject to additional and potentially significant capitalization requirements. These regulations could motivate the SDs and MSPs to increase collateral requirements or cash postings from their counterparties, including Generation.

Generation continues to monitor the rulemaking proceedings with respect to the capital and margin rules, but cannot predict to what extent, if any, further refinements to Dodd-Frank requirements may impact its cash flows or financial position, but such impacts could be material.

ComEd, PECO and BGE could also be subject to some Dodd-Frank requirements to the extent they were to enter into Swaps. However, at this time, management of ComEd, PECO and BGE continue to expect that their companies will not be materially affected by Dodd-Frank.

Energy Infrastructure Modernization Act. Since 2011, ComEd s distribution rates are established through a performance-based rate formula, pursuant to EIMA. 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. In addition, ComEd s earned rate of return on common equity is required to be within plus or minus 50 basis points (the collar) of the target rate of return determined as the annual average rate on 30-year treasury notes plus 580 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on distribution revenue. 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.

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Formula Rate Tariff and Annual Reconciliation. On April 16, 2014, ComEd filed its annual distribution formula rate to request a total increase to the revenue requirement of $269 million. On December 11, 2014, the ICC issued its final order which increased the revenue requirement by $232 million, reflecting an increase of $160 million for the initial revenue requirement for 2014 and an increase of $72 million related to the annual reconciliation for 2013. Approximately $23 million of the total $37 million revenue requirement disallowance is recoverable through other rider-based mechanisms. The rate increase was set using an allowed return on capital of 7.06% (inclusive of an allowed return on common equity of 9.25% for 2014 less a performance metrics penalty of 5 basis points for the 2013 reconciliation). The rates took effect in January 2015. ComEd and intervenors requested a rehearing on specific issues, which was denied by the ICC on January 28, 2015.

Grand Prairie Gateway Transmission Line. On December 2, 2013, ComEd filed a request to obtain the ICC s approval to construct a 60-mile overhead 345kV transmission line that traverses Ogle, DeKalb, Kane and DuPage Counties in Northern Illinois. On May 28, 2014, in a separate proceeding, FERC issued an order granting ComEd s request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd s transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd s control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd s transmission rate base. On October 22, 2014, the ICC issued an order approving ComEd s Grand Prairie Gateway Project over the objection of numerous landowners and the City of Elgin. Four parties filed timely applications for rehearing before the ICC. On November 25, 2014, the ICC denied the rehearing application filed by the Forest Preserve District of Kane County, but granted rehearing on the application of certain landowners who requested that the ICC consider an alternate route for a three-mile segment of the line in Kane County. The rehearing proceeding is currently pending and , the ICC must enter a final order on rehearing by April 24, 2015. On December 10, 2014, the ICC denied the remaining two applications for rehearing. On January 15, 2015, those two parties, the City of Elgin and the SKP landowner group and Utility Risk Management Corporation (collectively, the SKP/URMC party), each filed a Notice of Appeal with the Second District Appellate Court. On February 3, 2015, the ICC filed motions with the Second District Appellate Court seeking to extend the time for the ICC to file the record on appeal until after the ICC issues its Order on rehearing. The ICC also filed a motion to consolidate those appeals. ComEd expects to begin construction of the line in the second quarter of 2015 with an in-service date expected in the second quarter of 2017.

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 filed for rehearing of the July 2012 order, which was denied in June 2014. FERC and Ameren are in the process of determining the amount of any potential refund. 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. 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 of 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 those PJM Transmission Owners that changes to 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. PJM s compliance filing was made on July 22, 2013. On May 15, 2014, FERC denied the rehearing requests except with respect to one issue on when PJM could consider state and local laws in evaluating projects. FERC generally accepted the July 22, 2013, Compliance Filing but required several minor additional changes. FirstEnergy and at least one other party filed an appeal of the May 15, 2014, Order upholding PJM s right of first refusal language in the DC Circuit. Exelon has intervened in the FirstEnergy appeal. Several parties have filed requests for rehearing or clarification concerning the changes set forth in the May 15, 2014, Order. On December 18, 2014, FERC issued an order conditionally accepting part of the PJM-MISO interregional Order No. 1000 compliance filing, rejecting a MISO proposal concerning cost allocation for cross-border reliability projects and directing a further compliance filing by PJM and MISO.

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. BGE s formula rate includes a 10.8% base rate of return on common equity (ROE) and a 50 basis point incentive for participating in PJM (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 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 revenues subject to refund are limited to a fifteen month period, the earliest date from which the base ROE 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.

On August 21, 2014, FERC issued an order in the BGE and PHI companies proceeding, which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013. BGE, the PHI companies and the parties began settlement discussions under the guidance of a FERC administrative law judge on September 23, 2014. On November 24, 2014, the Settlement Judge informed FERC and the Chief Judge that the parties had reached an impasse and determined that a settlement was not possible. The Settlement Judge recommended termination of settlement proceedings. On November 26, 2014, the Chief Judge issued an order terminating the settlement proceeding, designating a presiding judge at the hearings and directing that an initial decision be issued by November 25, 2015.

On December 8, 2014, various state agencies in Delaware, Maryland, New Jersey, and D.C. filed a second complaint against BGE regarding the base ROE of the transmission business seeking a

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reduction from 10.8% to 8.8%. The filing of the second complaint creates a second refund window. By order issued on February 9, 2015, FERC established a hearing on the second complaint with the complainants requested refund effective date of December 8, 2014.

Based on the current status of the complaint filings, BGE believes it is probable that BGE s base ROE rate will be adjusted, and that a refund to customers of transmission revenue for the two maximum fifteen month periods will be required. However, BGE is unable to estimate the most likely refund amount for either complaint at this time, and has therefore established a reserve, which is not material, representing the low end of a reasonably possible estimated range of loss. Additionally, management is unable to estimate the maximum exposure of a potential refund at this time, which may have a material impact on BGE s results of operations and cash flows. The estimated annual ongoing reduction in revenues if FERC approved the ROEs requested by the parties in their filings is approximately $11 million. If FERC were to order a reduction of BGE s base ROE to 8.7% as sought in the first complaint (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the result of the first fifteen month refund window would be a refund to customers of approximately $13 million. If FERC were to order a reduction in BGE s base ROE to 8.8% as sought in the second complaint (while retaining 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment) and the refund period extended for a full fifteen months, the result would be a refund to customers of approximately $14 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. 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. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE s plan and surcharge. On March 26, 2014, the MDPSC approved as filed BGE s proposed 2014 project list, tariff and associated surcharge amounts, with a surcharge that became effective April 1, 2014. On November 17, 2014, BGE filed a surcharge update including a true-up of costs estimates included in the 2014 surcharge, along with its 2015 project list and cost estimates to be included in the 2015 surcharge. The filing was approved with a revised surcharge effective January 1, 2015. At its December 17, 2014 weekly Administrative Meeting, the MDPSC approved BGE s 2015 project list and the proposed surcharge for 2015. BGE will defer the difference between the surcharge revenues and program costs as a regulated asset or liability, which was immaterial to Exelon and BGE as of December 31, 2014.

In February 2014, the residential consumer advocate in Maryland filed an appeal with the Baltimore City Circuit Court to the decision issued by the MDPSC on BGE s infrastructure replacement plan. On September 5, 2014, the Baltimore City Circuit Court affirmed the MDPSC decision on BGE s infrastructure replacement plan and associated surcharge. On October 10, 2014, the residential consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court, however, a procedural schedule for the matter has not yet been set.

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 $7.0 billion at December 31, 2014. 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

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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. Generation assumes DOE will begin accepting SNF in 2025. The SNF acceptance date was based on management s estimates of the amount of time required for 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 Commitments and Contingencies 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 seventeen of its nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG), and none of Generation s applications for an operating license extension has been denied. For its remaining seven operating units, Generation is in various stages of the process of pursuing similar extensions and has filed license renewal applications for six operating nuclear units and has until 2021 to seek license renewal for one operating nuclear unit. 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 seventeen 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 $300 million per unit as of December 31, 2014. 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 $7.0 billion to approximately $8.6 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, 2014 at fair value of approximately $10.5 billion and have an estimated targeted annual pre-tax return of 6.0% to 6.3%.

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 2013 CARFRs rather than the 2014 CARFRs in performing its third quarter 2014 ARO update, Generation would have reduced the ARO by approximately $190 million as compared to

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the actual decrease to the ARO of $125 million; and ii) if the CARFR used in performing the third quarter 2014 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 $230 million and increased $40 million, respectively, as compared to the actual decrease of $125 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.

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, 2014	
Cost escalation studies		
Uniform increase in escalation rates of 25 basis points	$	810
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	$	290
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	$	420
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	$	630
Extend the estimated date for DOE acceptance of SNF to 2030	$	230
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with an increase in discount rates of 100 basis points	$	(270)
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with a decrease in discount rates of 100 basis points	$	1,100

For more information regarding accounting for nuclear decommissioning obligations, see Note 1 Significant Accounting Policies and Note 15 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements.

Goodwill (Exelon and ComEd)

As of December 31, 2014, Exelon s and ComEd s carrying amount of goodwill was approximately $2.7 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 below its carrying amount. Under the authoritative guidance, 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 its operating results are 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 operating results are regularly reviewed by segment management. Therefore, ComEd s operating segment is considered its only reporting unit.

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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. 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 assets acquired and liabilities assumed in an acquired business are recorded at their estimated fair values on the date of acquisition. The difference between the purchase price amount and the net fair value of assets acquired and liabilities assumed 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 Mergers, Acquisitions, and Dispositions 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, Acquisitions, and Dispositions and Note 10 Intangible Assets of the Combined Notes to Consolidated Financial Statements for further discussion.

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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. Indicators for impairment may include a 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 as well as the associated intangible contract assets recorded on the balance sheet. The cash flows from the generating units are generally evaluated at a regional portfolio level with cash flows generated from the 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 generating 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 generating assets (typically contracted renewables).

On a quarterly basis, Generation assesses its asset groups for indicators of impairment. If indicators are present, a recoverability test is performed. Impairment may occur if 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 often 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 judgment, 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 the value of either the long-lived asset or asset group, including any associated intangible contract assets and liabilities, as well as current period earnings by the amount of the impairment.

Generation evaluates natural gas and oil Upstream properties at least annually to determine if they are impaired. Impairment for natural gas and oil Upstream properties occurs if there are no firm plans to continue drilling, lease expiration is at risk, historical experience indicates a decline in carrying value below fair value or the price of the underlying commodity significantly declines.

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Exelon holds investments in coal-fired plants in Georgia 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 under the income approach, which uses a discounted cash flow analysis, that 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 contracts associated with the plants given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

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 recognizes an impairment, Generation would record its proportionate share of that impairment loss through its equity earnings (losses) of unconsolidated affiliates.

See Note 8 Impairment of Long-Lived Assets 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 Registrants complete depreciation studies every five years, or more frequently in an event, regulation action, or change in retirement patterns indicate an update is necessary. 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 Significant Accounting Policies 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

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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 and filed the updated depreciation rates with both FERC and the ICC in January 2014. This resulted 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. PECO expects to complete an updated depreciation study in 2015 and expects this to result in new depreciation rates effective in the first quarter of 2015 for electric transmission assets and first quarter 2016 for electric distribution and gas assets.

The MDPSC does not mandate the frequency or timing of BGE s depreciation studies. In July 2014, 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 and effective December 15, 2014.

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.

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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 EROA assumption used in calculating pension costs was 7.00%, 7.50% and 7.50% for 2014, 2013 and 2012, respectively. The weighted average EROA assumption used in calculating other postretirement benefit costs was 6.59%, 6.45% and 6.68% in 2014, 2013 and 2012, 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. Over time, Exelon has decreased its equity investments and increased its investments in fixed income securities and alternative investments within the pension asset portfolio 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 6.46% to estimate its 2015 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, 2014 were 10.93% and 5.01%, respectively, compared to an expected long-term return assumption of 7.00% and 6.59%, respectively.

Discount Rate. The discount rates used to determine the majority pension and other postretirement benefit obligations were 3.94% and 3.92%, respectively, at December 31, 2014. The discount rates at December 31, 2014 represent weighted-average rates for the majority of pension and other postretirement benefit plans. At December 31, 2014 and 2013, 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 used discount rates ranging from 3.94% and 3.92% to estimate the majority its 2015 pension and other postretirement benefit costs, respectively.

Health Care Reform Legislation. In March 2010, the Health Care Reform Acts (the Acts) were signed into law. The 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. Although Exelon has capped the rate of claims growth for certain legacy Exelon plan participants over age 65, exposure to the excise tax remains. 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 under what circumstances pre- and post-65 retiree benefits 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 impact the costs reported for Exelon s other postretirement benefit plans for participant populations with plan designs that do not have a cap on cost growth. 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. Exelon assumed an initial health care cost trend rate of 6.00% for 2014, decreasing to an ultimate health care cost trend rate of 5.00% in 2017.

Mortality. The mortality assumption is composed of a base table that represents the current expectation of life expectancy of the population adjusted by an improvement scale that attempts to anticipate future improvements in life expectancy. Exelon historically used a mortality base table for its accounting valuation that is consistent with the IRS required table for funding (referred to as RP-2000) and its corresponding improvement scale. During 2014, the Society of Actuaries (SOA) issued an updated mortality table (referred to as RP-2014) and improvement scale that suggests significant mortality improvement over the prior table. Exelon has a substantial employee population that provides a credible basis for mortality evaluation. Exelon engaged its actuaries to conduct a mortality study of Exelon s actual experience over a five year period as compared to the RP-2000 and RP-2014 tables, which resulted in a determination that the RP-2000 more closely aligns with Exelon s actual mortality experience. The study also considered available improvement scales. Management concluded that the RP-2000 and a more recent improvement scale issued by the SOA with certain adjustments to long-term improvement rates represent its best estimate of mortality. Exelon is utilizing the Scale BB 2-Dimensional improvement scale with long-term improvements of 0.75% (as compared to the 1% incorporated in the issued table) for its mortality improvement assumption. The change in assumption resulted in increases of $361 million and $117 million in the pension and other postretirement benefits obligations, respectively and an increase in 2015 cost of $45 million and $20 million for pension and other postretirement benefits, respectively.

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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 2014 cost:				
Discount rate [a]	0.5%	$ (71)	$ (34)	$ (105)
	(0.5)%	69	31	100
EROA	0.5%	(71)	(12)	(83)
	(0.5)%	71	12	83
Health care cost trend rate [b]	1.00%	N/A	35	35
	(1.00)%	N/A	(24)	(24)
Change in benefit obligation at December 31, 2014:				
Discount rate [a]	0.5%	(1,053)	(245)	(1,298)
	(0.5)%	1,156	271	1,427
Health care cost trend rate [b]	1.00%	N/A	162	162
	(1.00)%	N/A	(113)	(113)

(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.
(b) Changes in the plan design of certain other postretirement benefit plans have resulted in reduced sensitivity to the health care cost trend rate.

Average Remaining Service Period. For pension benefits, Exelon amortizes its unrecognized prior service costs and certain actuarial gains and losses, as applicable, based on participants average remaining service periods. The average remaining service period of defined benefit pension plan participants was 11.8 years, 11.8 years and 11.9 years for the years ended December 31, 2014, 2013 and 2012, 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 9.1 years, 8.7 years and 8.9 years for the years ended December 31, 2014, 2013 and 2012, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 10.1 years, 9.8 years and 10.1 years for the years ended December 31, 2014, 2013 and 2012, 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, 2014, 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 Regulatory Matters 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 Derivative Financial Instruments 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 the Constellation merger, 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 Constellation 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 Constellation 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 Note 11 Fair Value of Financial Assets and Liabilities and Note 12 Derivative Financial Instruments 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, 2014 and 2013 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 Income Taxes 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 Commitments and Contingencies 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 and expenses 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 and expenses 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 Accounts Receivable 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 customer risk segment. At December 31, 2013, BGE estimated the allowance for uncollectible accounts on customer receivables by assigning a reserve factor for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. At December 31, 2014, BGE changed to a methodology for estimating the allowance for uncollectible accounts, which was consistent with ComEd and PECO, as described above. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. ComEd, 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 Accounts Receivable 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, 2014, 2013 and 2012 set forth below include intercompany transactions, which are eliminated in Exelon s consolidated financial statements.

Net Income Attributable to Common Shareholders by Registrant

	2014 (b)	2013	Favorable (unfavorable) 2014 vs. 2013 variance	2012 (a)	Favorable (unfavorable) 2013 vs. 2012 variance
Exelon	$ 1,623	$ 1,719	$ (96)	$ 1,160	$ 559
Generation	835	1,070	(235)	562	508
ComEd	408	249	159	379	(130)
PECO	352	388	(36)	377	11
BGE	198	197	1	(9)	206

(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.
(b) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 financial results include CENG s results of operations on a fully consolidated basis from April 1, 2014, through December 31, 2014.

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Results of Operations Generation

	2014 [c]	2013	Favorable (unfavorable) 2014 vs. 2013 variance	2012 [b]	Favorable (unfavorable) 2013 vs. 2012 variance
Operating revenues	$ 17,393	$ 15,630	$ 1,763	$ 14,437	$ 1,193
Purchased power and fuel expense	9,925	8,197	(1,728)	7,061	(1,136)
Revenue net of purchased power and fuel expense [a]	7,468	7,433	35	7,376	57
Other operating expenses					
Operating and maintenance	5,566	4,534	(1,032)	5,028	494
Depreciation and amortization	967	856	(111)	768	(88)
Taxes other than income	465	389	(76)	369	(20)
Total other operating expenses	6,998	5,779	(1,219)	6,165	386
Equity in (losses) earnings of unconsolidated affiliates	(20)	10	(30)	(91)	101
Gain (loss) on sales of assets	437	13	424	(7)	20
Gain on consolidation and acquisition of businesses	289		289		
Operating income	1,176	1,677	(501)	1,113	564
Other income and (deductions)					
Interest expense	(356)	(357)	1	(301)	(56)
Other, net	406	355	51	246	109
Total other income and (deductions)	50	(2)	52	(55)	53
Income before income taxes	1,226	1,675	(449)	1,058	617
Income taxes	207	615	408	500	(115)
Net income	1,019	1,060	(41)	558	502
Net income (loss) attributable to noncontrolling interest	184	(10)	194	(4)	(6)
Net income attributable to membership interest	$ 835	$ 1,070	$ (235)	$ 562	$ 508

(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.

(c) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 financial results include CENG s results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.

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Net Income Attributable to Membership Interest

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Generation s net income attributable to membership interest decreased compared to the same period in 2013 primarily due to higher operating and maintenance expense and higher depreciation expense; partially offset by higher revenue, net of purchase power and fuel expense, higher other income, the gains recorded on the sale of Generation s ownership interest in generating stations, the bargain-purchase gain recorded related to the Integrys acquisition, and the gain recorded upon consolidation of CENG. The increase in operating and maintenance expense was largely due to increased labor contracting and materials expense due to the inclusion of CENG s results beginning April 1, 2014 and impairment charges related to 1) generating assets held-for-sale, 2) certain Upstream assets, and 3) wind generating assets. The increase in revenue, net of purchased power and fuel expense was primarily due to the inclusion of CENG s results beginning April 1, 2014, a decrease in fuel costs related to the cancellation of DOE spent nuclear fuel disposal fees, an increase in capacity prices, and favorable portfolio management activities in the New England an South regions, partially offset by lower realized energy prices related to executing Exelon s ratable hedging strategy, higher procurement costs for replacement power due to extreme cold weather in the first quarter of 2014, and unrealized mark-to-market losses in 2014. The increase in other income is primarily the result of increased realized and unrealized gain on NDT funds.

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 revenue, 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 revenue, net of 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.

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.

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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 gas and oil exploration and production activities, proprietary trading, distributed generation, 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 and investments in energy-related proprietary technology. 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 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.

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For the years ended December 31, 2014 compared to 2013 and December 31, 2013 compared to 2012, Generation s revenue net of purchased power and fuel expense by region were as follows:

	2014	2013	2014 vs. 2013 Variance	2014 vs. 2013 % Change	2012 [a]	2013 vs. 2012 Variance	2013 vs. 2012 % Change
Mid-Atlantic [b][c][g]	$ 3,417	$ 3,270	$ 147	4.5%	$ 3,433	$ (163)	(4.7)%
Midwest [d]	2,594	2,586	8	0.3%	2,998	(412)	(13.7)%
New England	351	185	166	89.7%	196	(11)	(5.6)%
New York [b][g]	483	(4)	487	n.m.	76	(80)	(105.3)%
ERCOT	317	436	(119)	(27.3)%	405	31	7.7%
Other Regions [e]	327	201	126	62.7%	131	70	53.4%
Total electric revenue net of purchased power and fuel expense	7,489	6,674	815	12.2%	7,239	(565)	(7.8)%
Proprietary Trading	42	(8)	50	n.m.	(14)	6	42.9%
Mark-to-market gains (losses)	(591)	504	(1,095)	n.m.	515	(11)	(2.1)%
Other [f]	528	263	265	100.8%	(364)	627	n.m.
Total revenue net of purchased power and fuel expense	$ 7,468	$ 7,433	$ 35	0.5%	$ 7,376	$ 57	0.8%

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

(b) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 financial results include CENG s results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.

(c) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.

(d) Results of transactions with ComEd are included in the Midwest region.

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

(f) 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 of $124 million, $488 million, and $1,098 million pre-tax for the twelve months ended December 31, 2014, December 31, 2013, and December 31, 2012, respectively.

(g) Includes $113 million and $169 million of purchased power from CENG prior to its consolidation on April 1, 2014 in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2014. 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 Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Generation s supply sources by region are summarized below:

			2014 vs. 2013			2013 vs. 2012	
Supply source (GWh)	**2014**	**2013**	**Variance**	**% Change**	**2012 [(a)]**	**Variance**	**% Change**
Nuclear generation [(b)]							
Mid-Atlantic	58,809	48,881	9,928	20.3%	47,337	1,544	3.3%
Midwest	94,000	93,245	755	0.8%	92,525	720	0.8%
New York	13,645		13,645	n.m.			%
	166,454	142,126	24,328	17.1%	139,862	2,264	1.6%
Fossil and renewables [(b)]							
Mid-Atlantic [(b)(d)]	11,025	11,714	(689)	(5.9)%	8,808	2,906	33.0%
Midwest	1,372	1,478	(106)	(7.2)%	971	507	52.2%
New England	5,233	10,896	(5,663)	(52.0)%	9,965	931	9.3%
New York	4		4	n.m.			n.m.
ERCOT	7,164	6,453	711	11.0%	6,182	271	4.4%
Other Regions [(e)]	7,955	6,664	1,291	19.4%	5,913	751	12.7%
	32,753	37,205	(4,452)	(12.0)%	31,839	5,366	16.9%
Purchased power							
Mid-Atlantic [(c)]	6,082	14,092	(8,010)	(56.8)%	20,830	(6,738)	(32.3)%
Midwest	2,004	4,408	(2,404)	(54.5)%	9,805	(5,397)	(55.0)%
New England	12,354	7,655	4,699	61.4%	9,273	(1,618)	(17.4)%
New York [(c)]	2,857	13,642	(10,785)	(79.1)%	11,457	2,185	19.1%
ERCOT	10,108	15,063	(4,955)	(32.9)%	23,302	(8,239)	(35.4)%
Other Regions [(e)]	14,795	14,931	(136)	(0.9)%	17,327	(2,396)	(13.8)%
	48,200	69,791	(21,591)	(30.9)%	91,994	(22,203)	(24.1)%
Total supply by region [(f)]							
Mid-Atlantic [(g)]	75,916	74,687	1,229	1.6%	76,975	(2,288)	(3.0)%
Midwest [(h)]	97,376	99,131	(1,755)	(1.8)%	103,301	(4,170)	(4.0)%
New England	17,587	18,551	(964)	(5.2)%	19,238	(687)	(3.6)%
New York	16,506	13,642	2,864	21.0%	11,457	2,185	19.1%
ERCOT	17,272	21,516	(4,244)	(19.7)%	29,484	(7,968)	(27.0)%
Other Regions [(e)]	22,750	21,595	1,155	5.3%	23,240	(1,645)	(7.1)%
Total supply	247,407	249,122	(1,715)	(0.7)%	263,695	(14,573)	(5.5)%

(a) Includes results for Constellation 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 includes the total output of plants that are fully consolidated (e.g. CENG). Nuclear generation for the year ended December 31, 2014 includes physical volumes of 11,408 GWh in Mid-Atlantic and 13,645 GWh in New York for CENG.
(c) Purchased power includes physical volumes of 2,489 GWh, 12,067 GWh, and 9,925 GWh in the Mid-Atlantic and 2,857 GWh, 12,165 GWh, and 9,350 GWh in New York as a result of the PPA with CENG for the years ended December 31, 2014, 2013, and 2012, respectively. On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, 100% of CENG volumes are included in nuclear generation.
(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 10,571 GWh, 8,762 GWh, and 12,958 GWh for the years ended December 31, 2014, 2013, and 2012, respectively.
(g) Includes sales to PECO through the competitive procurement process of 2,520 GWh, 5,070 GWh, and 7,762 GWh for the years ended December 31, 2014, 2013, and 2012, respectively. Sales to BGE of 5,093 GWh, 5,595 GWh, and 3,766 GWh were included for the years ended December 31, 2014, 2013, and

2012, respectively.

(h) Includes sales to ComEd under the RFP procurement of 5,259 GWh, 7,491 GWh and 4,152 GWh for the years ended December 31, 2014, 2013, and 2012, respectively.

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Mid-Atlantic

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $147 million was primarily due to the consolidation of CENG, the cancellation of the DOE spent nuclear fuel disposal fees, and favorable portfolio management optimization activities, partially offset by higher procurement costs for replacement power, lower nuclear volumes (excluding CENG), lower capacity revenues, and lower realized energy prices related to executing Generation s ratable hedging strategy.

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 energy prices and increased nuclear fuel costs, partially offset by the addition of Constellation in 2012, higher capacity revenues, and higher nuclear revenues.

Midwest

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The increase in revenue net of purchased power and fuel expense in the Midwest of $8 million was primarily due to higher capacity prices, higher nuclear volumes, and the cancellation of the DOE spent nuclear fuel disposal fee, partially offset by lower realized energy prices related to executing Generation s ratable hedging strategy.

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 energy prices, increased nuclear fuel costs, and lower capacity revenues, partially offset by higher nuclear revenues.

New England

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The $166 million increase in revenue net of purchased power and fuel expense in New England is primarily due to higher realized energy prices and favorable impacts from the restructuring of a fuel supply contract, partially offset by lower generation volume.

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.

New York

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The $487 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the consolidation of CENG.

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.

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ERCOT

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The $119 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily due to higher procurement costs for replacement power in the second quarter of 2014 and 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. The decreases were partially offset by higher generation volume in the first quarter of 2014.

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.

Other Regions

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The $126 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily due to higher generation volumes and higher realized energy prices.

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.

Mark-to-market

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. 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 losses on economic hedging activities were $591 million in 2014 compared to gains of $504 million in 2013. See Note 11 Fair Value of Financial Assets and Liabilities and Note 12 Derivative Financial Instruments 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, 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 Note 11 Fair Value of Financial Assets and Liabilities and Note 12 Derivative Financial Instruments 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, 2014 Compared to Year Ended December 31, 2013. The $265 million increase in other revenue net of purchased power and fuel was primarily due to a reduction in amortization of in-the-money energy contracts recorded at fair value at the Constellation merger date and an increase related to the amortization of out-of-the money energy contracts recorded at fair value upon the consolidation of CENG partially offset by a loss on gas inventory from lower of cost or market adjustments in 2014. See Note 10 Intangible Assets of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles.

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 10 Intangible Assets 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 2014, as compared to 2013 and 2012, 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, required capital investment, benefits costs associated with labor, insurance, property taxes, unit contingent costs, suspended DOE nuclear waste storage fee (as discussed further in Note 22 Commitments and Contingencies), 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.

	2014	2013	2012
Nuclear fleet capacity factor [(a)]	94.3%	94.1%	92.7%
Nuclear fleet production cost per MWh [(a)]	$ 19.33	$ 19.83	$ 19.50

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon. As of April 1, 2014, CENG is included at ownership.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The nuclear fleet capacity factor, which excludes Salem, increased in 2014 compared to 2013. While total days offline are greater in 2014 as compared to 2013, the larger capacity units were online for more days in 2014. Additionally, with the addition of the CENG nuclear facilities there were more days offline in 2014 associated with units where Exelon s ownership percentage diminishes the impact on capacity factor. For 2014 and 2013, planned refueling outage days totaled 275 and 233, respectively, and non-refueling outage days totaled 92 and 75, respectively. Production cost per MWh was lower in 2014 compared to 2013 due to elimination of the SNF disposal fee in 2014, partially offset by inclusion of the ownership share of CENG.

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.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2014 compared to 2013, consisted of the following:

	Increase (Decrease) [a]
Impairment and related charges of certain generating assets [b]	$ 506
Labor, other benefits, contracting and materials [c]	361
Accretion expense	78
Corporate allocations [d]	69
Regulatory fees and assessments	51
Maryland merger commitments	44
Nuclear refueling outage costs, including the co-owned Salem plant [e]	54
Increase in asbestos bodily injury reserve	16
Midwest Generation bankruptcy charges	(26)
ARO update	(29)
Merger and integration costs	(29)
Pension and non-pension postretirement benefits expense	(81)
Other	18
Increase in operating and maintenance expense	$ 1,032

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 operating results include CENG s results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.
(b) Reflects the operating and maintenance expense associated with the impairment of certain generating assets held-for-sale, Upstream assets, and wind generating assets during 2014.
(c) Reflects an increase of labor, other benefits, contracting and materials costs primarily due to the inclusion of CENG beginning April 1, 2014. Also includes cost of sales of our other business activities that are not allocated to a region.
(d) Reflects an increased share of corporate allocated costs primarily due to the 2014 CENG integration.
(e) Reflects the impact of increased nuclear outage days primarily due to the inclusion of CENG beginning April 1, 2014.

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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)
Asbestos 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 outages during 2013.
(e) The decrease in cost allocations during 2013 primarily reflects merger and energy 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.

Depreciation and Amortization

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The increase in depreciation and amortization expense was primarily due to the inclusion of CENG s results on a fully consolidated basis beginning April 1, 2014 and an increase in ongoing capital expenditures.

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.

Taxes Other Than Income

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The increase was primarily due to the inclusion of CENG s results on a fully consolidated basis beginning April 1, 2014.

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.

Equity in Earnings (Losses) of Unconsolidated Affiliates

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The year-over-year change in Equity in earnings (losses) of unconsolidated affiliates is primarily the result of the consolidation of CENG s results of operations beginning April 1, 2014, which were previously accounted for under the equity method of accounting.

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Gain (Loss) on Sales of Assets

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The year-over-year change in Gain (loss) on sales of assets reflects $411 million of gains recorded on the sale of Generation s ownership interests in Safe Harbor Water Power Corporation, Fore River and West Valley generating stations in 2014. Refer to Note 4 Mergers, Acquisitions and Dispositions in the Combined Notes to Consolidated Financial Statements for additional information.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The year-over-year change in Gain (loss) on sales of assets primarily reflects an $8 million gain recorded on the sale of Maryland Clean Coal in 2013.

Gain on Consolidation and Acquisition of Businesses

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The increase in Gain on consolidation and acquisition of businesses is primarily related to a $261 million gain upon consolidation of CENG resulting from the difference in fair value of CENG s net assets as of April 1, 2014 and the equity method investment previously recorded on Generation s and Exelon s books and the settlement of pre-existing transactions between Generation and CENG, and a $28 million bargain-purchase gain related to the lntegrys acquisition.

Interest Expense

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Interest expense for the year ended December 31, 2014 compared to the same period in 2013 remained relatively level.

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.

Other, Net

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The increase in Other, net primarily reflects $31 million of favorable tax settlements related to Constellation s pre-acquisition 2009-2012 tax returns and the net increase in realized and unrealized gains related to the NDT funds of Generation s Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $67 million and $122 million for the year ended December 31, 2014 and 2013, respectively, related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units. Refer to Note 15 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT funds.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase 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. Other, net also reflects $122 million and $117 million for the year ended December 31, 2013 and 2012, respectively, related to the contractual elimination of income tax expense (benefit) associated with the NDT funds of the Regulatory Agreement Units. Refer to Note 15 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT funds.

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The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for 2014, 2013 and 2012:

	2014	2013	2012
Net unrealized gains on decommissioning trust funds	$ 134	$ 146	$ 105
Net realized gains on sale of decommissioning trust funds	$ 77	$ 24	$ 51

Effective Income Tax Rate.

Generation s effective income tax rates for the years ended December 31, 2014, 2013 and 2012 were 16.9%, 36.7% and 47.3%, 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.

Results of Operations ComEd

	2014	2013	Favorable (Unfavorable) 2014 vs. 2013 Variance	2012	Favorable (Unfavorable) 2013 vs. 2012 Variance
Operating revenue	$ 4,564	$ 4,464	$ 100	$ 5,443	$ (979)
Purchased power expense	1,177	1,174	(3)	2,307	1,133
Revenue net of purchased power expense [(a)]	3,387	3,290	97	3,136	154
Other operating expenses					
Operating and maintenance	1,429	1,368	(61)	1,345	(23)
Depreciation and amortization	687	669	(18)	610	(59)
Taxes other than income	293	299	6	295	(4)
Total other operating expenses	2,409	2,336	(73)	2,250	(86)
Gain on sales of assets	2		2		
Operating income	980	954	26	886	68
Other income and (deductions)					
Interest expense, net	(321)	(579)	258	(307)	(272)
Other, net	17	26	(9)	39	(13)
Total other income and (deductions)	(304)	(553)	249	(268)	(285)
Income before income taxes	676	401	275	618	(217)
Income taxes	268	152	(116)	239	87

Net income	$ 408	$ 249	$ 159	$ 379	$ (130)

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

Net Income

Year Ended December 31, 2014, Compared to Year Ended December 31, 2013. ComEd s Net income for the year ended December 31, 2014, was higher than the same period in 2013, primarily due

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to the 2013 remeasurement of Exelon s like-kind exchange tax position, and increased electric distribution and transmission earnings resulting from increased capital investment, partially offset by unfavorable weather.

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 and unfavorable weather, partially offset by increased electric distribution and transmission earnings resulting from increased costs and capital investments and higher allowed ROE. See Note 3 Regulatory Matters and Note 14 Income Taxes of the Combined Notes to Consolidated Financial Statements in the 2013 10-K for additional information.

Operating Revenue Net of Purchased Power Expense

There are certain drivers of Operating revenue 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 Revenue 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 revenue related to supplied energy, which is fully offset in Purchased power expense. Therefore, customer choice programs have no impact on Revenue net of purchased power expense.

The number of retail customers participating in customer choice programs was 2,426,921, 2,630,185 and 1,627,150 at December 31, 2014, 2013 and 2012, respectively, representing 63%, 68% and 43% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 80%, 81% and 65% of ComEd s retail kWh sales for the years ended December 31, 2014, 2013 and 2012, respectively.

The changes in ComEd s Revenue net of purchased power expense for the year ended 2014 compared to the same period in 2013 consisted of the following:

	Increase
Weather	$ (16)
Electric distribution revenue	(2)
Transmission revenue	30
Regulatory required programs	52
Revenue subject to refund	(9)
Pricing and customer mix	5
Uncollectible accounts recovery, net	41
Other	(4)
Increase in revenue net of purchased power	$ 97

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

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because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. For the year ended December 31, 2014, unfavorable weather conditions, primarily during the summer months, reduced Operating revenue net of purchased power expense when compared to prior year.

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, 2014 and 2013 consisted of the following:

	Twelve Months Ended December 31,			**% Change**	
Heating and Cooling Degree-Days	**2014**	**2013**	**Normal**	**From 2013**	**From Normal**
Heating Degree-Days	7,027	6,603	6,341	6.4%	10.8%
Cooling Degree-Days	799	933	842	(14.4)%	(5.1)%

Volume

For the year ended December 31, 2014 Revenue net of purchased power expense remained relatively consistent, as compared to the same period in 2013.

Electric Distribution Revenue

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. Under EIMA, distribution revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, allowed ROE, and other billing determinants. In addition, ComEd s allowed rate of return on common equity is the annual average rate on 30-year treasury notes plus 580 basis points, subject to a collar of plus or minus 50 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on revenue. During the year ended December 31, 2014, distribution revenue decreased $2 million at ComEd, primarily due to lower Operating and maintenance expenses primarily driven by the impacts of certain OPEB plan design changes, partially offset by increased capital investment. See Operating and Maintenance Expense below, ITEM 1. BUSINESS Commonwealth Edison Company, Note 3 Regulatory Matters and Note 16 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenue

Under a FERC approved formula, transmission revenue varies 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, 2014, ComEd recorded increased revenue of $30 million due to increased capital investments. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs

This represents the change in Operating revenue collected under approved riders to recover costs incurred for regulatory programs such as ComEd s energy efficiency and demand response and purchase power administrative costs. The riders are designed to provide full and current cost recovery.

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The costs of these programs are included in Operating and maintenance expense. Refer to the Operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net

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.

Pricing and Customer Mix

The increase in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to higher overall effective rates due to decreased usage across all major customer classes and change in customer mix for the years ended December 31, 2014, and 2013, respectively.

Revenue Subject to Refund

ComEd records revenue subject to refund based upon its best estimate of customer collections that may be required to be refunded. For the year ended December 31, 2014, ComEd recorded $9 million of revenue subject to refund associated with Rider AMP. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial statements for additional information.

Other

Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs and recoveries of environmental costs associated with MGP sites, recovery of energy procurement costs, for which an equal and offsetting amount is reflected in Depreciation and amortization expense during the periods presented.

The changes in ComEd s Revenue net of purchased power expense for 2013 compared to 2012 consisted of the following:

	Increase
Weather	$ (17)
Volume	(2)
Electric distribution revenue	168
Discrete impacts of the 2012 distribution rate case order	13
Transmission revenue	14
Regulatory required programs	20

Uncollectible accounts recovery, net	(58)
Other	16
Increase in revenue net of purchased power	$ 154

Weather

For the year ended December 31, 2013, the increase in Revenue 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.

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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:

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

Revenue 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 Revenue

During the year ended December 31, 2013, ComEd recorded increased revenue of $168 million under EIMA, primarily due to increased capital investments, increased operating expenses, and higher allowed ROE. 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, which reestablished ComEd s position on the return on its pension asset, resulting in an increase to revenue in 2013. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenue

During the year ended December 31, 2013, ComEd recorded increased revenue during the year ended December 31, 2013 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.

Operating and Maintenance Expense

	Year Ended December 31,		Increase	Year Ended December 31,		Increase
	2014	2013	2014 vs. 2013	2013	2012	2013 vs. 2012
Operating and maintenance expense baseline	$ 1,211	$ 1,202	$ 9	$ 1,202	$ 1,199	$ 3
Operating and maintenance expense regulatory required programs (a)	218	166	52	166	146	20
Total operating and maintenance expense	$ 1,429	$ 1,368	$ 61	$ 1,368	$ 1,345	$ 23

(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 revenue.

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The changes in Operating and maintenance expense for year ended December 31, 2014, compared to the same period in 2013 and changes for the year ended December 31, 2013, compared to the same period in 2012, consisted of the following:

	Increase 2014 vs. 2013	Increase 2013 vs. 2012
Baseline		
Labor, other benefits, contracting and materials [(a)]	$ 56	$ 48
Pension and non-pension postretirement benefits expense [(b)]	(85)	3
Storm-related costs	(11)	(10)
Uncollectible accounts expense provision[(c)]	12	(10)
Uncollectible accounts expense recovery, net[(c)]	29	(48)
Other	8	20
	9	3
Regulatory required programs		
Energy efficiency and demand response programs	52	20
Increase in operating and maintenance expense	$ 61	$ 23

(a) Reflects decreased contracting costs resulting from new projects associated with EIMA for the years ended December 31, 2014 and 2013. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding EIMA.
(b) Primarily reflects decreased non-pension costs associated with OPEB plan design changes during 2014. See Note 16 Retirement Benefits of the Combined Notes to the Consolidated Financial Statements for additional information regarding plan changes.
(c) 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 revenue for the periods presented.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2014 compared to 2013 and 2013 compared to 2012, consisted of the following:

	Increase 2014 vs. 2013	Increase 2013 vs. 2012
Depreciation associated with higher plant balances	$ 46	$ 22
Amortization of storm-related regulatory assets [(a)]		4
Amortization of MGP regulatory assets [(b)]	(18)	27
Amortization of other regulatory assets	(3)	6
Other	(7)	
Increase in depreciation and amortization expense	$ 18	$ 59

(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 revenue during the periods presented.

Taxes Other Than Income

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. 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 remained relatively flat for the twelve months ended December 31, 2014, compared to the same periods in 2013.

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Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Taxes other than income taxes increased primarily due to increased Illinois electricity distribution taxes.

Interest Expense, Net

The changes in Interest expense, net for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

	Increase (Decrease) 2014 vs. 2013	Increase (Decrease) 2013 vs. 2012
Interest expense related to uncertain tax positions [(a)]	$ (275)	$ 281
Interest expense on debt (including financing trusts) [(b)]	16	2
Other	1	(11)
Increase (decrease) in interest expense, net	$ (258)	$ 272

(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.
(b) Primarily reflects interest expense related to the First Mortgage Bonds. See Note 13 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s debt obligations.

Other, Net

The changes in Other, net for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

	Increase (Decrease) 2014 vs. 2013	Increase (Decrease) 2013 vs. 2012
Interest income related to uncertain tax positions [(a)]	$	$ (20)
AFUDC Equity	(8)	
Other	(1)	7
Increase (decrease) in Other, net	$ (9)	$ (13)

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

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Effective Income Tax Rate

ComEd s effective income tax rates for the years ended December 31, 2014, 2013 and 2012, were 39.6%, 37.9% and 38.7%, 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.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2014	2013	% Change 2014 vs 2013	Weather-Normal % Change	2012	% Change 2013 vs 2012	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	27,230	27,800	(2.1)%	0.3%	28,528	(2.6)%	(0.6)%
Small commercial & industrial	32,146	32,305	(0.5)%	(0.3)%	32,534	(0.7)%	0.2%
Large commercial & industrial	27,847	27,684	0.6%	0.7%	27,643	0.1%	(0.3)%
Public authorities & electric railroads	1,358	1,355	0.2%	(0.7)%	1,272	6.5%	4.2%
Total retail deliveries	88,581	89,144	(0.6)%	0.2%	89,977	(0.9)%	(0.1)%

	As of December 31,		
Number of Electric Customers	**2014**	**2013**	**2012**
Residential	3,502,386	3,480,398	3,455,546
Small commercial & industrial	369,053	367,569	365,357
Large commercial & industrial	1,998	1,984	1,980
Public authorities & electric railroads	4,815	4,853	4,812
Total	3,878,252	3,854,804	3,827,695

Electric Revenue	2014	2013	% Change 2014 vs 2013	2012	% Change 2013 vs 2012
Retail Sales [(a)]					
Residential	$ 2,074	$ 2,073	%	$ 3,037	(31.7)%
Small commercial & industrial	1,335	1,250	6.8%	1,339	(6.6)%
Large commercial & industrial	434	427	1.6%	395	8.1%
Public authorities & electric railroads	46	48	(4.2)%	44	9.1%
Total retail sales	3,889	3,798	2.4%	4,815	(21.1)%
Other revenue [(b)]	675	666	1.4%	628	6.1%
Total electric revenue	$ 4,564	$ 4,464	2.2%	$ 5,443	(18.0)%

(a) Reflects delivery revenue and volume 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, revenue 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 revenue.

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Results of Operations PECO

	2014	2013	Favorable (unfavorable) 2014 vs. 2013 variance	2012	Favorable (unfavorable) 2013 vs. 2012 variance
Operating revenue	$ 3,094	$ 3,100	$ (6)	$ 3,186	$ (86)
Purchased power and fuel	1,261	1,300	39	1,375	75
Revenue net of purchased power and fuel expense [(a)]	1,833	1,800	33	1,811	(11)
Other operating expenses					
Operating and maintenance	866	748	(118)	809	61
Depreciation and amortization	236	228	(8)	217	(11)
Taxes other than income	159	158	(1)	162	4
Total other operating expenses	1,261	1,134	(127)	1,188	54
Operating income	572	666	(94)	623	43
Other income and (deductions)					
Interest expense, net	(113)	(115)	2	(123)	8
Other, net	7	6	1	8	(2)
Total other income and (deductions)	(106)	(109)	3	(115)	6
Income before income taxes	466	557	(91)	508	49
Income taxes	114	162	48	127	(35)
Net income	352	395	(43)	381	14
Preferred security dividends and redemption		7	7	4	(3)
Net income attributable to common shareholder	$ 352	$ 388	$ (36)	$ 377	$ 11

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

Net Income Attributable to Common Shareholder

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The decrease in Net income attributable to common shareholder was driven primarily by an increase in Operating and maintenance expense partially offset by an increase in Operating revenue net of purchase power and fuel expense and a decrease in Income tax expense.

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.

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Operating Revenue Net of Purchased Power and Fuel Expense

Electric and gas revenue 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 revenue net of purchased power and fuel expense.

Electric and gas revenue 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 revenue collected from customers related to supplied energy and natural gas service. Customer Choice Program activity has no impact on electric and gas revenue net of purchase power and fuel expense. The number of retail customers purchasing energy from a competitive electric generation supplier was 546,900, 531,500, and 496,500 at December 31, 2014, 2013 and 2012, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 70%, 68%, and 66% of PECO s retail kWh sales for the years ended December 31, 2014, 2013 and 2012, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 78,400, 66,400, and 52,700 at December 31, 2014, 2013 and 2012, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 22%, 19%, and 16% of PECO s mmcf sales for the years ended December 31, 2014, 2013 and 2012, respectively.

The changes in PECO s Operating revenue net of purchased power and fuel expense for the year ended December 31, 2014 compared to the same period in 2013 consisted of the following:

		Increase	
	Electric	**Gas**	**Total**
Weather	$ (15)	$ 13	$ (2)
Volume	2	5	7
Pricing	(1)	(3)	(4)
Regulatory required programs	33		33
Other	(1)		(1)
Total increase	$ 18	$ 15	$ 33

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 revenue net of purchased power and fuel expense was lower due to the impact of unfavorable 2014 summer and fourth quarter weather conditions, partially offset by the impact of favorable first quarter 2014 winter weather conditions in PECO s service territory.

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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, 2014 compared to the same period in 2013 and normal weather consisted of the following:

	Twelve Months Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2014**	**2013**	**Normal**	**From 2013**	**From Normal**
Heating Degree-Days	4,749	4,474	4,603	6.1%	3.2%
Cooling Degree-Days	1,311	1,411	1,301	(7.1)%	0.8%

Volume

The increase in Operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, primarily reflects the impact of moderate economic and customer growth partially offset by energy efficiency initiatives on customer usages for gas and residential electric and a shift in the volume profile across classes from commercial and industrial classes to residential classes for electric.

Pricing

The decrease in gas operating revenue net of fuel expense as a result of pricing is primarily attributable to lower overall effective rates due to increased retail gas usage.

Regulatory Required Programs

This represents the change in operating revenue collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The 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.

The changes in PECO s operating revenue 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 increase (decrease)	$ (32)	$ 21	$ (11)

Weather

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

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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:

Heating and Cooling Degree-Days	Twelve Months Ended December 31, 2013	2012	Normal	% Change From 2012	From Normal
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 revenue net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflected the impact of energy efficiency initiatives on customer usages as well as a shift in the volume profile across classes from residential classes to commercial and industrial classes, partially offset by the oil refineries returning to full production in 2013 as well as moderate economic growth. The decrease in gas revenue net of fuel expense related to delivery volume, exclusive of the effects of weather, primarily reflected a decline in residential use per customer.

Pricing

The decrease in electric operating revenue 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 revenue 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 revenue. As a result of decreases in operating revenue 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 reflected 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 revenue, see Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further explanation.

Other

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

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Operating and Maintenance Expense

	Twelve Months Ended December 31, 2014	2013	Increase 2014 vs. 2013	Twelve Months Ended December 31, 2013	2012	(Decrease) 2013 vs. 2012
Operating and maintenance expense baseline	$ 761	$ 668	$ 93	$ 668	$ 723	$ (55)
Operating and maintenance expense regulatory required programs [(a)]	105	80	$ 25	80	86	$ (6)
Total operating and maintenance expense	$ 866	$ 748	$ 118	$ 748	$ 809	$ (61)

(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 revenue.

The changes in Operating and maintenance expense for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

	Increase (Decrease) 2014 vs. 2013	Increase (Decrease) 2013 vs. 2012
Baseline		
Labor, other benefits, contracting and materials	$ 12	$ 10
Storm-related costs	100[(a)]	(49)
Pension and non-pension postretirement benefits expense	(5)	(12)
Merger and integration costs	(7)	(8)
Corporate allocation	5	
Uncollectible accounts expense	(9)	
Other	(3)	4
	93	(55)
Regulatory required programs		
Smart meter	7	4
Energy efficiency	17	(9)
Consumer education program		(1)
Other	1	
	25	(6)
Increase (decrease) in operating and maintenance expense	$ 118	$ (61)

(a) Total storm-related costs include approximately $85 million of incremental storm costs, including the February 5, 2014 ice storm and the significant July storms.

Depreciation and Amortization Expense

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The increase in Depreciation and amortization expense, net for 2014, compared to 2013 was primarily due to ongoing capital expenditures and regulatory required programs.

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.

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Taxes Other Than Income

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Taxes other than income remained relatively consistent.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in Taxes other than income for 2013 compared to 2012 was primarily due to GRT expense slightly offset by sales and use tax.

Interest Expense, Net

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Interest expense, net remained relatively consistent.

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.

Other, Net

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Other, net remained relatively consistent.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Other, net remained relatively consistent.

Effective Income Tax Rate

PECO s effective income tax rates for the years ended December 31, 2014, 2013 and 2012 were 24.5%, 29.1% and 25.0%, respectively. See Note 14 Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rates.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2014	2013	% Change 2014 vs. 2013	Weather-Normal % Change	2012	% Change 2013 vs. 2012	Weather-Normal % Change

Retail Deliveries [(a)]							
Residential	13,222	13,341	(0.9)%	0.5%	13,233	0.8%	%
Small commercial & industrial	8,025	8,101	(0.9)%	%	8,063	0.5%	(1.1)%
Large commercial & industrial	15,310	15,379	(0.4)%	(0.1)%	15,253	0.8%	1.5%
Public authorities & electric railroads	937	930	0.8%	0.8%	943	(1.4)%	(1.4)%
Total electric retail deliveries	37,494	37,751	(0.7)%	0.1%	37,492	0.7%	0.3%

	As of December 31,		
Number of Electric Customers	**2014**	**2013**	**2012**
Residential	1,434,011	1,423,068	1,417,773
Small commercial & industrial	149,149	149,117	148,803
Large commercial & industrial	3,103	3,105	3,111
Public authorities & electric railroads	9,734	9,668	9,660
Total	1,595,997	1,584,958	1,579,347

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Electric Revenue	2014	2013	% Change 2014 vs. 2013	2012	% Change 2013 vs. 2012
Retail Sales [(a)]					
Residential	$ 1,555	$ 1,592	(2.3)%	$ 1,689	(5.7)%
Small commercial & industrial	423	433	(2.3)%	462	(6.3)%
Large commercial & industrial	217	224	(3.1)%	232	(3.4)%
Public authorities & electric railroads	32	30	6.7%	31	(3.2)%
Total retail	2,227	2,279	(2.3)%	2,414	(5.6)%
Other revenue [(b)]	221	221	%	226	(2.2)%
Total electric revenue	$ 2,448	$ 2,500	(2.1)%	$ 2,640	(5.3)%

(a) Reflects delivery volumes and revenue 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 reflect the cost of energy and transmission.

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

PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2014	2013	% Change 2014 vs. 2013	Weather-Normal % Change	2012	% Change 2013 vs. 2012	Weather-Normal % Change
Retail Deliveries [(a)]							
Retail sales	62,734	57,613	8.9%	2.2%	49,767	15.8%	(0.1)%
Transportation and other	27,208	28,089	(3.1)%	(1.0)%	26,687	5.3%	0.5%
Total gas deliveries	89,942	85,702	4.9%	1.2%	76,454	12.1%	0.1%

Number of Gas Customers	As of December 31, 2014	2013	2012
Residential	462,663	458,356	454,502
Commercial & industrial	42,686	42,174	41,836
Total retail	505,349	500,530	496,338
Transportation	855	909	903
Total	506,204	501,439	497,241

Gas revenue	2014	2013	% Change 2014 vs. 2013	2012	% Change 2013 vs. 2012
Retail Sales [(a)]					
Retail sales	$ 608	$ 562	8.2%	$ 509	10.4%
Transportation and other	38	38	%	37	2.7%

Total gas revenue	$ 646	$ 600	7.7%	$ 546	9.9%

(a) Reflects delivery volumes and revenue 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 reflect the cost of natural gas.

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Results of Operations BGE

	2014	2013	Favorable (unfavorable) 2014 vs. 2013 variance	2012	Favorable (unfavorable) 2013 vs. 2012 variance
Operating revenue	$ 3,165	$ 3,065	$ 100	$ 2,735	$ 330
Purchased power and fuel expense	1,417	1,421	4	1,369	(52)
Revenue net of purchased power and fuel expense [(a)]	1,748	1,644	104	1,366	278
Other operating expenses					
Operating and maintenance	717	634	(83)	728	94
Depreciation and amortization	371	348	(23)	298	(50)
Taxes other than income	221	213	(8)	208	(5)
Total other operating expenses	1,309	1,195	(114)	1,234	39
Operating income	439	449	(10)	132	317
Other income and (deductions)					
Interest expense, net	(106)	(122)	16	(144)	22
Other, net	18	17	1	23	(6)
Total other income and (deductions)	(88)	(105)	17	(121)	16
Income before income taxes	351	344	7	11	333
Income taxes	140	134	(6)	7	(127)
Net income	211	210	1	4	206
Preference stock dividends	13	13		13	
Net income (loss) attributable to common shareholder	$ 198	$ 197	$ 1	$ (9)	$ 206

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

Net Income (Loss) Attributable to Common Shareholder

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Net income attributable to common shareholder remained relatively consistent primarily due to an increase in Revenue net of purchased power and fuel expense as a result of the December 2013 and 2014 electric and gas distribution rate order issued by the MDPSC offset by increases in Operating and maintenance expense and Depreciation expense.

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 Revenue 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.

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Operating Revenue 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 revenue 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 revenue and purchased power expense. The number of customers electing to select a competitive natural gas supplier affects gas cost adjustment revenue 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 364,000, 399,000 and 362,000 at December 31, 2014, 2013 and 2012, respectively, representing 29%, 32% and 29% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 60%, 61% and 60% of BGE s retail kWh sales for the years ended December 31, 2014, 2013 and 2012, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 161,000, 172,000 and 143,000 at December 31, 2014, 2013 and 2012, respectively, representing 25%, 26% and 22% of total retail customers, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 53%, 54% and 56% of BGE s retail mmcf sales for the years ended December 31, 2014, 2013 and 2012, respectively.

The changes in BGE s Operating revenue net of purchased power and fuel expense for the year ended December 31, 2014 compared to the same period in 2013 consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
Distribution rate increases	$ 57	$ 28	$ 85
Commodity margin	(1)	12	11
Regulatory required programs	13	(1)	12
Transmission revenue	10		10
Other	$ (12)	$ (2)	$ (14)
Total increase	$ 67	$ 37	$ 104

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 revenue 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 revenue per customer, by customer class, regardless of changes in consumption levels. This allows BGE to recognize revenue at MDPSC-approved levels per customer, regardless of what BGE s actual distribution volumes were for a billing period. Therefore, while this revenue is 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.

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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, 2014 compared to the same period in 2013 and normal weather consisted of the following:

	Twelve Months Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2014**	**2013**	**Normal**	**From 2013**	**From Normal**
Heating Degree-Days	5,091	4,744	4,662	7.3%	9.2%
Cooling Degree-Days	732	869	876	(15.8)%	(16.4)%

Distribution Rate Increases.

The increase in Operating revenue net of purchased power and fuel expense was primarily due to MDPSC rate orders effective December 13, 2013 and December 15, 2014 approving increases to electric and natural gas distribution rates charged to customers. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Commodity Margin.

The increase in Revenue net of purchased power and fuel expense as a result of commodity margin for the year ended December 31, 2014 compared to the same period in 2013 was primarily due the higher gas margins earned due to extreme cold weather during the first quarter of 2014 under BGE s market-based rate incentive mechanism. See Note 12 Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for further information.

Regulatory Required Programs.

This represents the change in revenue 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 electric revenue during the year ended December 31, 2014 compared to the same period in 2013 was due to the recovery of higher energy efficiency program costs.

Transmission.

The increase in transmission revenue rates for the year ended December 31, 2014 compared to the same period in 2013 was primarily due to the impact of new transmission rates charged to customers that became effective in June 2014. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other.

Other revenue decreased during the year ended December 31, 2014 compared to the same period in 2013. Other revenue, which can vary from period to period, includes miscellaneous revenue such as service application and late payment fees.

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The changes in BGE s Revenue 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	$ 82	$ 31	$ 113
Distribution rate increases	69	24	93
Regulatory required programs	36	6	42
Other	26	4	30
Total increase	$ 213	$ 65	$ 278

The changes in heating and cooling degree days for the twelve months ended 2013 and 2012, consisted of the following:

	Twelve Months Ended December 31,			% Change	
Heating and Cooling Degree-Days [(a)]	2013	2012	Normal	From 2012	From Normal
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 Revenue 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.

Distribution Rate Increases.

The increase in Revenue net of purchased power and fuel expense as a result of distribution rate increases for the year ended December 31, 2013 compared to the same period in 2012 was primarily due to MDPSC rate orders effective February 23, 2013 and December 13, 2013 approving increases to electric and natural gas distribution rates charged to customers. 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 revenue 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 revenue during the year ended December 31, 2013 compared to the same period in 2012 was due to the recovery of higher energy efficiency programs costs.

Other.

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

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

	Increase (Decrease) 2014 vs. 2013	Increase (Decrease) 2013 vs. 2012
Baseline		
Labor, other benefits, contracting and materials	$ 22	$ 20
Pension and non-pension postretirement benefits expense	8	
Storm-related costs [a]	21	(62)
Uncollectible accounts expense	17	
Merger transaction costs	5	(21)
Charitable contributions [b]		(28)
Other	10	(3)
Increase (Decrease) in operating and maintenance expense	$ 83	$ (94)

(a) 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 were 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 were capital costs.

(b) 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.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

	Increase (Decrease) 2014 vs. 2013	Increase (Decrease) 2013 vs. 2012
Depreciation expense [a]	$ 25	$ 18
Regulatory asset amortization	(1)	31[b]
Other	(1)	1
Increase in depreciation and amortization expense	$ 23	$ 50

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

(b) Regulatory asset amortization for the year ended December 31, 2013 compared to the same period in 2012 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 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

	Increase (Decrease) 2014 vs. 2013	Increase (Decrease) 2013 vs. 2012
Property tax	$ 2	$ (2)
Franchise tax	4	7
Other	2	
Increase in taxes other than income	$ 8	$ 5

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Interest Expense, Net

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The decrease in Interest expense, net for 2014 compared to 2013 was primarily due to favorable interest rates in 2014 on long-term debt balances.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in Interest expense, net in 2013 compared to 2012 was primarily due to 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.

Effective Income Tax Rate

BGE s effective income tax rates for the years ended December 31, 2014, 2013 and 2012 were 39.9%, 39.0% and 63.6%, 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.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2014	2013	% Change 2014 vs. 2013	Weather-Normal % Change	2012	% Change 2013 vs. 2012	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	12,974	13,077	(0.8)%	n.m.	12,719	2.8%	n.m.
Small commercial & industrial	3,086	3,035	1.7%	n.m.	2,990	1.5%	n.m.
Large commercial & industrial	14,191	14,339	(1.0)%	n.m.	14,956	(4.1)%	n.m.
Public authorities & electric railroads	311	317	(1.9)%	n.m.	329	(3.6)%	n.m.
Total electric deliveries	30,562	30,768	(0.7)%	n.m.	30,994	(0.7)%	n.m.

Number of Electric Customers	As of December 31, 2014	2013	2012
Residential	1,125,369	1,120,431	1,116,233
Small commercial & industrial	112,972	112,850	112,994
Large commercial & industrial	11,730	11,652	11,580
Public authorities & electric railroads	290	292	319
Total	1,250,361	1,245,225	1,241,126

Electric Revenue	2014	2013	% Change 2014 vs. 2013	2012	% Change 2013 vs. 2012

Retail Sales [a]					
Residential	$ 1,404	$ 1,404	%	$ 1,274	10.2%
Small commercial & industrial	271	257	5.4%	248	3.6%
Large commercial & industrial	491	439	11.8%	393	11.7%
Public authorities & electric railroads	32	31	3.2%	30	3.3%
Total retail	2,198	2,131	3.1%	1,945	9.6%
Other revenue	262	274	(4.4)%	238	15.1%
Total electric revenue	$ 2,460	$ 2,405	2.3%	$ 2,183	10.2%

(a) Reflects delivery revenue 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.

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BGE Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2014	2013	% Change 2014 vs. 2013	Weather-Normal % Change	2012	% Change 2013 vs. 2012	Weather-Normal % Change
Retail Deliveries [d]							
Retail sales	99,194	94,020	5.5%	n.m.	86,946	8.1%	n.m.
Transportation and other [e]	9,242	12,210	(24.3)%	n.m.	15,751	(22.5)%	n.m.
Total gas deliveries	108,436	106,230	2.1%	n.m.	102,697	3.4%	n.m.

Number of Gas Customers	As of December 31, 2014	2013	2012
Residential	609,626	611,532	610,827
Commercial & industrial	44,200	44,162	44,228
Total	653,826	655,694	655,055

Gas revenue	2014	2013	% Change 2014 vs. 2013	2012	% Change 2013 vs. 2012
Retail Sales [d]					
Retail sales	$ 622	$ 592	5.1%	$ 494	19.8%
Transportation and other [e]	83	68	22.1%	58	17.2%
Total gas revenue	$ 705	$ 660	6.8%	$ 552	19.6%

(d) Reflects delivery revenue 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 9,242 mmcfs ($72 million), 12,210 mmcfs ($55 million), and 15,751 mmcfs ($51 million) for the years ended 2014, 2013 and 2012, respectively.

Liquidity and Capital Resources

Exelon s and Generation s current year activity presented below includes the activity of CENG, from the integration date effective April 1, 2014 through December 31, 2014. All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

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 billion, $0.6 billion and $0.6 billion, respectively. The Registrants revolving credit facilities are in place until 2019. In addition, Generation has $0.5 billion in bilateral facilities with banks which have various expirations between October 2015 and January 2017. 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.

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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 Debt and Credit Agreements 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 Regulatory Matters and 22 Commitments and Contingencies 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 took effect in 2013. On August 8, 2014, this funding relief was extended for five years. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to make qualified pension plan contributions of $447 million to its qualified pension plans in 2015, of which Generation, ComEd, PECO and BGE expect to contribute $230 million, $138 million, $40 million and $1 million, respectively. Exelon s and Generation s expected qualified pension plan contributions above include $36 million related to legacy CENG plans that will be funded by CENG as provided in an Employee Matters Agreement (EMA) between Exelon and CENG. Unlike the qualified pension plans, Exelon s non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $15 million in 2015, of which Generation, ComEd, PECO and BGE will make payments of $6 million, $1 million, $1 million, and $1 million respectively. See Note 16 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for the Registrants 2014 and 2013 pension contributions.

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To the extent interest rates decline significantly or the pension plans do not earn the expected asset return rates, annual pension contribution requirements in future years could increase, especially in years 2017 and beyond. Additionally, the contributions above could change if Exelon changes its pension funding strategy.

Unlike qualified pension plans, other postretirement benefit plans are not subject to statutory minimum contribution requirements and certain plans are not funded. Exelon s management has historically considered several factors in determining the level of contributions to its funded other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery). Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $37 million in 2015, of which Generation, ComEd, PECO, and BGE expect to contribute $17 million, $2 million, $0 million, and $17 million, respectively. See Note 16 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for the Registrants 2014 and 2013 other postretirement benefit contributions.

See the Contractual Obligations section 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:

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 as of December 31, 2014 may be as much as $810 million, of which approximately $310 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 and interest impacts will increase by a material amount.

Exelon, Generation, and ComEd expect to receive tax refunds of approximately $430 million, $190 million, and $260 million, respectively, in 2015. PECO expects to make tax payments of approximately $6 million related to IRS positions settling in 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.

On December 19th, 2014, President Obama signed H.R. 5771, The Tax Increase Prevention Act. The Act included an extension of 50% bonus depreciation for 2014. As a result of the 50% bonus depreciation extension, Exelon, ExGen, ComEd, PECO, and BGE are estimated to generate incremental cash of approximately $600 million, $272 million, $217 million, $53 million, and $46 million, respectively. The resulting cash benefits are expected primarily in 2015. The cash generated is an acceleration of tax benefits that Registrants would have received over the normal depreciable life of the property. Furthermore, the extension of 50% bonus depreciation will result in a decrease to Generation s Domestic Production Activities Deduction, reducing cash tax benefits and increasing income tax expense by approximately $30 million for 2014. ComEd s 2014 revenue requirement is expected to decrease by approximately $12 million (after-tax) due to the extension of 50% bonus depreciation.

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The following table provides a summary of the major items affecting Exelon s cash flows from operations for the years ended December 31, 2014, 2013 and 2012:

	2014 (d)	2013	2014 vs. 2013 Variance	2012 (c)	2013 vs. 2012 Variance
Net income	$ 1,820	$ 1,729	$ 91	1,171	$ 558
Add (subtract):					
Non-cash operating activities [(a)]	5,884	4,159	1,725	5,588	(1,429)
Pension and non-pension postretirement benefit contributions	(617)	(422)	(195)	(462)	40
Income taxes	(143)	883	(1,026)	544	339
Changes in working capital and other noncurrent assets and liabilities [(b)]	(1,047)	(185)	(862)	(731)	546
Option premiums paid, net	38	(36)	74	(114)	78
Counterparty collateral received (paid), net	(1,478)	215	(1,693)	135	80
Net cash flows provided by operations	$ 4,457	$ 6,343	$ (1,886)	$ 6,131	$ 212

(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. See note 23 Supplemental Financial Information for further detail on non-cash operating activity.
(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.
(c) Exelon s 2012 activity includes the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.
(d) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.

Cash flows provided by operations for the year ended December 31, 2014, 2013 and 2012 by Registrant were as follows:

	2014	2013	2012
Exelon [(a)(b)]	$ 4,457	$ 6,343	$ 6,131
Generation [(a)(b)]	1,826	3,887	3,581
ComEd	1,326	1,218	1,334
PECO	712	747	878
BGE [(b)]	740	561	485

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(b) Exelon s and Generation s 2012 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. BGE s 2012 activity includes its activity for the twelve months ended December 31, 2012.

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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, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for 2014, 2013 and 2012 were as follows:

Generation

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. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on the exchange or in the OTC markets. During 2014, 2013 and 2012, Generation had net collections (payments) receipts of counterparty cash collateral of $(1,507) million, $162 million and $95 million, respectively. Net collections (payments) each year were primarily due to market conditions that resulted in changes to Generation s net mark-to-market position. In addition, in 2014 the exchanges increased initial margin rates, which required Generation to post higher amounts of initial margin.

During 2014, 2013 and 2012, Generation had net collections (payments) of approximately $38 million, $(36) million and $(114) 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

For the year ended December 31, 2014 and 2013, ComEd had a working capital deficit of $263 million and $508 million, respectively. The working capital deficit is primarily attributable to the increase in short-term borrowings in 2014 and an increase in short-term borrowings and short-term debt due within one year in 2013. Cash flows from operating activities are sufficient to meet operating requirements; however, increased capital investment in infrastructure improvements and modernization pursuant to EIMA, transmission upgrades and expansion may require external debt financing or additional capital contributions from parent.

During 2014, 2013 and 2012, ComEd s net payables to Generation for energy purchases related to its supplier forward contract and ICC-approved RFP contracts increased/(decreased) by $5 million, $(16) million and $(15) million, respectively. During 2014, 2013 and 2012 ComEd s payables to other energy suppliers for energy purchases increased by $27 million, $35 million and $20 million, respectively.

PECO

During 2014, 2013 and 2012, PECO s payables to Generation for energy purchases increased/(decreased) by $(9) million, $(17) million and $17 million, respectively, and payables to other energy suppliers for energy purchases increased/(decreased) by $10 million, $39 million and $(22) million, respectively.

BGE

During 2014, 2013 and 2012, BGE s payables to Generation for energy purchases increased/(decreased) by $13 million, $(4) million and $23 million, respectively, and payables to other energy suppliers for energy purchases increased/(decreased) by $(7) million, $(12) million and $40 million, respectively.

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Cash Flows from Investing Activities

Cash flows used in investing activities for the year ended December 31, 2014, 2013, and 2012 by Registrant were as follows:

	2014	2013	2012
Exelon [(a)(b)]	$ (4,599)	$ (5,394)	$ (4,576)
Generation [(a)(b)]	(1,767)	(2,916)	(2,629)
ComEd	(1,655)	(1,387)	(1,212)
PECO	(649)	(531)	(328)
BGE [(b)]	(622)	(571)	(573)

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(b) Exelon s and Generation s 2012 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. BGE s 2012 activity includes its activity for the twelve months ended December 31, 2012.

Generation

As a result of consolidating CENG during the second quarter of 2014, Generation recorded $129 million of cash from CENG, reflected in Generation s cash flows from investing activities above. See Note 5 Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for further information.

Generation closed on the sale of its 67% equity interest in the 417 MW Safe Harbor Water Power Corporation hydroelectric facility on the Susquehanna River in Pennsylvania for a purchase price of approximately $615 million during the third quarter of 2014. The proceeds from the sale are reflected in Generation s cash flows from investing activities above. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for further information.

During the third quarter of 2014, Generation established $65 million in restricted cash as part of the EGTP project financing which is reflected in Generation s cash flows from investing activities above. See Note 13 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for more information.

Generation closed on the sale of its 41.98% and 31.28% ownership interests in the Keystone and Conemaugh coal-fired power plants and related equity interests in Keystone Fuels, LLC and Conemaugh Fuels, LLC, respectively, for a purchase price of approximately $473 million during the fourth quarter of 2014. The proceeds from the sale are reflected in Generation s cash flows from investing activities above. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for further information.

During the fourth quarter of 2014, Generation closed on the sale of its fully-owned equity interest in Fore River and West Valley generating stations, for a combined purchase price of approximately $577 million. The proceeds from the sale are reflected in Generation s cash flows from investing activities above. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for further information.

During the fourth quarter of 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. for a purchase price of $332 million, including net working capital. The acquisition costs from the sale are reflected in Generation s cash flows from investing activities above. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for further information.

Generation has entered into several agreements to acquire equity interests in privately held and development stage entities which develop energy-related technology. The agreements include a series of scheduled investment commitments, including in-kind services contributions, totaling approximately $167 million through 2018 to fund anticipated planned capital and operating needs of the associated companies.

Generation has executed, or expects to execute, construction and services contracts to build new gas turbine units in Texas and Maryland and a new biomass-fueled cogeneration facility in Georgia. The total estimated expenditures for these projects are approximately $1.8 billion and achievement of commercial operations is expected between 2015 and 2017 for all these projects.

Capital expenditures by Registrant for the year ended December 31, 2014, 2013, and 2012 and projected amounts for 2015 are as follows:

	Projected 2015 (a)	**2014**	**2013**	**2012**
Exelon (b)(e)(f)	$ 7,200	$ 6,077	$ 5,395	$ 5,789
Generation (b)(e)(f)	3,625	3,012	2,752	3,554
ComEd (c)	2,200	1,689	1,433	1,246
PECO	550	661	537	422
BGE (e)	700	620	587	582
Other (d)	125	95	86	(15)

(a) Total projected capital expenditures do not include adjustments for non-cash activity.
(b) Includes nuclear fuel.
(c) The projected capital expenditures include $617 million of expected incremental spending 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.
(d) Other primarily consists of corporate operations and BSC.
(e) Exelon s and Generation s 2012 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. BGE s 2012 activity includes its activity for the twelve months ended December 31, 2012.
(f) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, CENG is included on a fully consolidated basis beginning April 1, 2014.

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

In 2014, Exelon and its affiliates initiated a comprehensive project to ensure corporate-wide compliance with Version 5 of the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection Standards (CIP V.5) which will become effective on April 1, 2016. Generation, ComEd, PECO and BGE will be incurring incremental capital expenditures in 2014 through 2016 associated with the CIP V.5 compliance implementation project, which are included in projected capital expenditures above.

Generation

Approximately 33% and 7% of the projected 2015 capital expenditures at Generation are for the acquisition of nuclear fuel and investments in renewable energy and natural gas generation, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that they will fund capital expenditures with internally generated funds and borrowings.

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ComEd, PECO and BGE

Approximately 85%, 95% and 96% 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 s and BGE s capital expenditures include investments related to their respective smart meter programs. 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 that recommends ComEd, PECO, and BGE, perform assessments of their transmission lines. In compliance with this guidance, ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd s, PECO s and BGE s forecasted 2015 capital expenditures above reflect capital spending for remediation to be completed in 2017.

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 the year ended December 31, 2014, 2013, and 2012 by Registrant were as follows:

	2014	2013	2012
Exelon [(a)(b)]	411	(826)	(1,085)
Generation [(a)(b)]	(537)	(384)	(777)
ComEd	359	61	(212)
PECO	(250)	(361)	(382)
BGE [(b)]	(85)	(48)	128

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(b) Exelon s and Generation s 2012 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. BGE s 2012 activity includes its activity for the twelve months ended December 31, 2012.

Debt.

See Note 13 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants debt issuances and retirements. Debt activity for 2014, 2013 and 2012 by Registrant was as follows:

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During the year ended December 31, 2014, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Junior Subordinated Notes [(a)]	2.50%	June 1, 2024	$ 1,150	Used to finance a portion of the acquisition of PHI and for general corporate purposes
Generation	Nuclear Fuel Procurement Contract	3.35%	June 30, 2018	38	Used for procurement of uranium
Generation	ExGen Renewables I Nonrecourse Debt [(b)]	LIBOR + 4.25%	February 6, 2021	300	Used for general corporate purposes
Generation	ExGen Texas Power Nonrecourse Debt [(b)]	LIBOR + 4.75%	September 18, 2021	675	Used for general corporate purposes
Generation	Energy Efficiency Project Financing	4.12%	December 31, 2015	12	Funding to install energy conservation measures in Washington, DC
Generation	AVSR DOE Nonrecourse Debt [(b)]	2.78 - 3.14%	January 5, 2037	126	Used for Antelope Valley solar development
Generation	Nuclear Fuel Procurement Contract	3.25%	June 30, 2018	32	Used for procurement of uranium
ComEd	First Mortgage Bonds Series 115	2.15%	January 15, 2019	300	Used to refinance maturing mortgage bonds and general corporate purposes
ComEd	First Mortgage Bonds Series 116	4.70%	January 15, 2044	350	Used to refinance maturing mortgage bonds and general corporate purposes
ComEd	First Mortgage Bonds Series 117	3.10%	November 1, 2024	250	Used to repay commercial paper and general corporate purposes
PECO	First and Refunding Mortgage Bonds	4.15%	October 1, 2044	300	Used to repay at maturity first and refunding mortgage bonds due October 1, 2014, and general corporate purposes

(a) See Note 13 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of the Junior Subordinated Notes and related forward equity purchase contract, which are expected to be remarketed in 2017.
(b) See Note 13 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.

On January 13, 2015, Generation issued $750 million in aggregate principal amount of Senior Notes. The Senior Notes carry an annual interest rate of 2.950%, payable semi-annually, commencing July 15, 2015 and due January 15, 2020. The proceeds of the Senior Notes will be used to fund the optional redemption of Exelon s $550 million, 4.550% Senior Notes due June 15, 2015, expected to occur on February 17, 2015, and for general corporate purposes. In addition to the issuance, Exelon terminated floating-to-fixed interest rate swaps that had been designated as cash flow hedges. As the original forecasted transactions were a series of future interest payments over a ten year period, a portion of the anticipated interest payments at this time are probable not to occur. As a result Exelon will reclassify $26 million of deferred losses in AOCI to Other, net in the first quarter of 2015.

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During the year ended December 31, 2013, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	CEU Upstream Nonrecourse Debt	2.210 - 2.440%	July 22, 2016	$ 5	Used to fund Upstream gas activities
Generation	AVSR DOE Nonrecourse Debt	2.535 - 3.353%	January 5, 2037	227	Used for Antelope Valley solar development
Generation	Social Security Administration Project Financing	2.93%	February 18, 2015	1	Used to install conservation measures for the Social Security Administration Headquarters facility in Maryland
Generation	Energy Efficiency Project Financing	4.40%	August 31, 2014	9	Used for funding to install energy conservation measures in Beckley, West Virginia
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	613	Used for general corporate purposes
ComEd	First Mortgage Bonds, Series 114	4.60%	August 15, 2043	350	Used to repay outstanding commercial paper obligations and for general corporate purposes
PECO	First and Refunding Mortgage Bonds due	1.20%	October 15, 2016	300	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
PECO	First and Refunding Mortgage Bonds	4.80%	October 15, 2043	250	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
BGE	Notes	3.35%	July 1, 2023	300	Used to partially refinance Notes due July 1, 2013 and for general corporate purposes

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During the year ended December 31, 2012, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	CEU Upstream Nonrecourse Debt	Variable Rate	July 16, 2016	$ 78	Used to fund Upstream gas activities
Generation	AVSR DOE Nonrecourse Debt	Fixed Rate	January 5, 2037	220	Used for Antelope Valley solar development
Generation	Senior Notes	4.25%	June 15, 2022	523	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	Senior Notes	5.60%	June 15, 2042	788	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	Constellation Solar Horizons Nonrecourse Debt	2.50%	June 7, 2030	38	Used for funding for Maryland solar development
ComEd	First Mortgage Bonds, Series 113	3.80%	October 1, 2042	350	Used to repay outstanding commercial paper obligations and for general corporate purposes
PECO	First and Refunding Mortgage Bonds	2.38%	September 15, 2022	350	Used to pay at maturity First Mortgage Bonds due October 1, 2012 and for general corporate purposes
BGE	Notes	2.80%	August 15, 2022	250	Used to repay total outstanding commercial paper obligations and for general corporate purposes

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During the year ended December 31, 2014, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	2003 Senior Notes	5.35%	January 15, 2014	$ 500
Generation	Pollution Control Loan	4.10%	July 1, 2014	20
Generation	Continental Wind Nonrecourse Debt [(a)]	6.00%	February 28, 2033	20
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	3
Generation	ExGen Renewables I Nonrecourse Debt [(a)]	LIBOR + 4.25%	February 6, 2021	18
Generation	ExGen Texas Power Nonrecourse Debt [(a)]	LIBOR + 4.75%	September 18, 2021	2
Generation	AVSR DOE Nonrecourse Debt [(a)]	2.33% - 3.55%	January 5, 2037	15
Generation	Constellation Solar Horizons Nonrecourse Debt [(a)]	2.56%	September 7, 2030	2
Generation	Sacramento PV Energy Nonrecourse Debt [(a)]	2.56%	December 31, 2030	2
Generation	Energy Efficiency Project Financing	4.12%	December 31, 2015	12
ComEd	Mortgage Bonds Series 110	1.63%	January 15, 2014	600
ComEd	Pollution Control Series 1994C	5.85%	January 15, 2014	17
PECO	First and Refunding Mortgage Bonds	5.00%	October 1, 2014	250
BGE	Rate Stabilization Bonds	5.72%	April 1, 2017	35
BGE	Rate Stabilization Bonds	5.72%	October 1, 2014	35

(a) See Note 13 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.

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During the year ended December 31, 2013, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	Kennett Square Capital Lease	7.83%	September 1, 2020	$ 3
Generation	Solar Revolver Nonrecourse Debt	Variable Rate	July 7, 2014	113
Generation	Constellation Solar Horizons Nonrecourse Debt	2.56%	September 7, 2030	2
Generation	Sacramento Energy Nonrecourse Debt	2.68%	December 31, 2030	2
Generation [(a)]	Series A Junior Subordinated Debentures	8.63%	June 15, 2063	450
Generation	Energy Efficiency Project Financing	4.40%	August 31, 2014	9
ComEd	First Mortgage Bonds, Series 92	7.63%	April 15, 2013	125
ComEd	First Mortgage Bonds, Series 94	7.50%	July 1, 2013	127
PECO	First and Refunding Mortgage Bonds	5.60%	October 15, 2013	300
BGE	Rate Stabilization Bonds	5.72%	April 1, 2017	67
BGE	Notes	6.13%	July 1, 2013	400

(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.

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During the year ended December 31, 2012, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon	Fixed rate Medium Term Notes	7.30%	June 1, 2012	$ 2
Exelon	Fixed rate Senior Notes	7.60%	April 1, 2032	442
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	2
Generation	3-year term rate Armstrong Co. 2009 A, Pollution Control Notes	5.00%	December 1, 2042	46
Generation	CEU Upstream Nonrecourse Debt	Variable Rate	July 16, 2016	89
Generation	Solar Revolver Nonrecourse Debt	Variable Rate	July 7, 2014	17
Generation	MEDCO Tax-Exempt Bonds	Variable Rate	April 1, 2024	75
Generation	Sacramento PV Energy Nonrecourse Debt	Variable Rate	March 12, 2012	2
ComEd	First Mortgage Bonds, Series 98	6.15%	March 15, 2012	450
PECO	First and Refunding Mortgage Bonds	4.75%	October 1, 2012	225
PECO	First and Refunding Mortgage Bonds	4.00%	December 1, 2012	150
BGE	Rate Stabilization Bonds	5.72%	April 1, 2016	8
BGE	Rate Stabilization Bonds	5.47%	October 1, 2012	55
BGE	Medium Term Notes	Variable Rate	June 15, 2012	110

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 for the year ended December 31, 2014, 2013 and 2012 by Registrant were as follows:

	2014	2013	2012
Exelon [(a)]	$ 1,486	$ 1,249	1,716
Generation [(a)]	1,066	625	1,626
ComEd	307	220	105
PECO	320	333	347
BGE [(b)]	13	13	13

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014. As such, includes $421 million of distributions to EDF in 2014.
(b) Relates to dividends paid on BGE s preference 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.

Second Quarter 2014 Dividend

On May 6, 2014, the Exelon Board of Directors declared a second quarter 2014 regular quarterly dividend of $0.31 per share on Exelon s common stock payable on June 10, 2014, to shareholders of record of Exelon at the end of the day on May 16, 2014.

Third Quarter 2014 Dividend

On July 29, 2014, the Exelon Board of Directors declared a third quarter 2014 regular quarterly dividend of $0.31 per share on Exelon s common stock payable on September 10, 2014 to shareholders of record of Exelon at the end of the day on August 15, 2014.

Fourth Quarter 2014 Dividend

On October 21, 2014, the Exelon Board of Directors declared a fourth quarter 2014 regular quarterly dividend of $0.31 per share on Exelon s common stock payable on December 10, 2014 to shareholders of record of Exelon at the end of the day on November 14, 2014.

First Quarter 2015 Dividend

On January 27, 2015, the Exelon Board of Directors declared a first quarter 2015 regular quarterly dividend of $0.31 per share on Exelon s common stock payable on March 10, 2015, to shareholders of record of Exelon at the end of the day on February 13, 2015.

Short-Term Borrowings. Short-term borrowings incurred (repaid) during 2014, 2013 and 2012 by Registrant were as follows:

	2014	2013	2012
Generation [(a)]	$ 17	$ 13	$ (52)
ComEd	120	184	
BGE	(15)	135	
Other [(b)]			(145)
Exelon [(a)]	$ 122	$ 332	$ (197)

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(b) 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 2014, 2013 and 2012 by the Registrants.

Contributions from Parent/Member. Contributions from Parent/Member (Exelon) during 2014, 2013 and 2012 by Registrant were as follows:

	2014	2013	2012
Generation	$ 53	$ 26	$ 48
ComEd [(a)]	278	176	11
PECO	24	27	9
BGE			66

(a) In 2014 and 2013, represents indemnification from Exelon in relation to the like-kind exchange transaction. For 2014 , also represents contributions from Exelon to support expanded capital programs.

Distributions to Noncontrolling Interests of Consolidated VIE. On April 1, 2014, Generation loaned $400 million to CENG, the proceeds of which were used to make a distribution to EDFI of $400 million. See Note 5 Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for additional information on the integration of CENG.

Other. For the year ended December 31, 2014, other financing activities primarily consisted of financing costs associated with the acquisition of PHI, other project financing and various debt issuance costs. See notes 4, 13, and 19 of the Combined Notes to Consolidated Financial Statements for additional information.

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 $8.5 billion in aggregate total commitments of which $7.3 billion was available as of December 31, 2014, 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 2014 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, 2014, it would have been required to provide incremental collateral of $2.4 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 $4.6 billion. If ComEd lost its investment grade credit ratings as of December 31, 2014, it would have been required to provide incremental collateral of $14 million, which is well within its current available credit facility capacity of $998 million. If PECO lost its investment grade credit rating as of December 31, 2014 it would not be required to provide collateral pursuant to PJM s credit policy and could have been required to provide collateral of $36 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, 2014 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 $79 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE s current available credit facility capacity of $600 million.

Exelon Credit Facilities

See Note 13 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants credit facilities and short term borrowing activity.

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Other Credit Matters

Capital Structure. At December 31, 2014, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE
Long-term debt	46%	30%	42%	41%	36%
Long-term debt to affiliates [(a)]	1%	7%	1%	3%	5%
Common equity	52%		55%	56%	53%
Member s equity		63%			
Preference Stock					4%
Commercial paper and notes payable	1%		2%		2%

(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 Variable Interest Entities 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, 2014, in addition to the net contribution or borrowing as of December 31, 2014, are presented in the following table:

	Maximum Contributed	Maximum Borrowed	December 31, 2014 Contributed (Borrowed)
Generation	$ 84	$ 573	$
PECO	129	35	
BSC	15	360	(261)
Exelon Corporate	780	N/A	261

Investments in Nuclear Decommissioning Trust Funds. Exelon, Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning 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 and CENG s investment policies 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. As of December 31, 2014, ComEd had $702 million available in long-term debt refinancing authority and

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$943 million available in new money long-term debt financing authority from the ICC. During the fourth quarter of 2014, ComEd requested an extension of the expiration date of the refinancing authority from the ICC. In January 2015, the ICC approved the extension of the refinancing authority, which now expires on February 27, 2017. As of December 31, 2014, PECO had $1.1 billion available in long-term debt financing authority from the PAPUC. As of December 31, 2014, BGE had $1.4 billion 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, 2014, 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 Regulatory Matters 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, 2014, Exelon had retained earnings of $10,910 million, including Generation s undistributed earnings of $3,803 million, ComEd s retained earnings of $851 million consisting of retained earnings appropriated for future dividends of $2,490 million partially offset by $1,639 million of unappropriated retained deficit, PECO s retained earnings of $681 million and BGE s retained earnings $1,203 million. See Note 22 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

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Contractual Obligations

The following tables summarize the Registrants future estimated cash payments as of December 31, 2014 under existing contractual obligations, including payments due by period. See Note 22 Commitments and Contingencies 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	2015	2016-2017	2018-2019	Due 2020 and beyond	All Other
Long-term debt [a]	$ 21,372	$ 1,736	$ 3,661	$ 2,387	$ 13,588	$
Interest payments on long-term debt [b]	13,105	922	1,755	1,435	8,993	
Liability and interest for uncertain tax positions [c]	779					779
Capital leases	32	3	8	9	12	
Operating leases [d]	1,158	99	204	156	699	
Purchase power obligations [e]	2,084	590	884	295	315	
Fuel purchase agreements [f]	10,020	1,661	2,555	2,048	3,756	
Electric supply procurement [f]	1,510	1,057	453			
AEC purchase commitments [f]	8	1	2	2	3	
Curtailment services commitments [f]	115	40	63	12		
Long-term renewable energy and REC commitments [g]	1,516	75	152	162	1,127	
Other purchase obligations [h]	894	336	408	66	84	
Construction commitments [i]	1,143	43	1,100			
PJM regional transmission expansion commitments [j]	786	259	414	113		
Spent nuclear fuel obligation [k]	1,021				1,021	
Pension minimum funding requirement [l]	1,892	447	782	424	239	
Total contractual obligations	$ 57,435	$ 7,269	$ 12,441	$ 7,109	$ 29,837	$ 779