EXELON CORP
Form 10-K
February 10, 2016
Table of Contents

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, 2015

OR

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

Commission File Number	Exact Name of Registrant as Specified in its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379	23-2990190

	(800) 483-3220	
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:	
	New York

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

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

Table of Contents

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	Smaller 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, 2015 was as follows:

Exelon Corporation Common Stock, without par value	$ 27,049,825,290
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, 2016 was as follows:

Exelon Corporation Common Stock, without par value	919,924,742
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,973
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 2016 Annual Meeting of

Shareholders and the Commonwealth Edison Company 2016 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.

Table of Contents

TABLE OF CONTENTS

Table of Contents

Table of Contents

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities	
Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
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
AMP	Advanced Metering Program
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
CAP	Customer Assistance Program

Table of Contents

Other Terms and Abbreviations

CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
D.C. 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 and its subsidiaries
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

Table of Contents

Other Terms and Abbreviations	
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out
LLRW	Low-Level Radioactive Waste
LTIP	Long-Term Incentive Plan
MATS	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 Calvert Cliffs, Nine Mile Point, Ginna, Clinton, Oyster Creek, Three Mile Island, Zion (a former ComEd unit), and portions of Peach Bottom (a former PECO unit)
NOSA	Nuclear Operating Services Agreement
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
PHI	Pepco Holdings, Inc.

Table of Contents

Other Terms and Abbreviations

PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
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
ROE	Return on Common Equity
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

Table of Contents

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 23; 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.

Table of Contents

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 and power marketing 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 800-483-3220.

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 Power 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.

Table of Contents

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 25 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 first quarter of 2016. 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, including renewable energy, to both wholesale and retail customers. The retail sales include commercial, industrial and residential customers. 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 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 provides 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 s customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation also 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 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.

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 4,007 MW. See ITEM 2. PROPERTIES for additional information on these sites.

Generation and EDF also entered into a Put Option Agreement on April 1, 2014, pursuant to which EDF has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

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 a fully consolidated basis in 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 were 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.

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.

Table of Contents

Antelope Valley Solar Ranch One. On September 30, 2011, Exelon completed the 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 through completion of the project 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, 2015, Generation has sold certain generating assets with total 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, 2015, the generating resources of Generation consisted of the following:

Type of Capacity	**MW**
Owned generation assets [(a)(b)]	
Nuclear	19,460
Fossil (primarily natural gas)	9,682
Renewable [(c)]	3,599
Owned generation assets	32,741
Long-term power purchase contracts	7,419
Total generating resources	40,160

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

Generation has six reportable segments, the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power 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 36% of capacity).

Table of Contents

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 37% 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 Power Regions is an aggregate of regions not considered individually significant (approximately 6% of capacity).

See Note 25 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 19,460 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 Cliffs, Nine Mile Point [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 2015, 2014 and 2013 electric supply (in GWh) generated from the nuclear generating facilities was 68%, 67% and 57%, 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.

10

Table of Contents

During 2015, 2014 and 2013, the nuclear generating facilities operated by Generation achieved capacity factors of 93.7%, 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 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 or other incident.

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 January 6, 2016, the NRC categorized Clinton and Dresden unit 2 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, 2015, 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.

Table of Contents

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, Limerick Units 1 and 2, Byron Units 1 and 2 and Braidwood 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 [(c)]	1	1988	2046
	2	1988	2047
Byron [(c)]	1	1985	2044
	2	1987	2046
Calvert Cliffs [(c)]	1	1975	2034
	2	1977	2036
Clinton [(d)]	1	1987	2026
Dresden [(c)]	2	1970	2029
	3	1971	2031
LaSalle [(b)]	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 December 2014, Generation submitted applications to the NRC to extend the operating licenses of LaSalle Units 1 and 2 by 20 years.
(c) Stations for which the NRC has issued renewed operating licenses.
(d) Although timing has been delayed, Generation currently plans to seek license renewal for Clinton and has advised the NRC that any license renewal application would not be filed until the first quarter of 2021.
(e) In December 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019.

Generation currently has a license renewal application pending for 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.

Table of Contents

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. Once all projects are completed in 2016, Generation will have placed in-service 538 MWs of new nuclear generation.

As of December 31, 2015, under the nuclear uprate program, Generation has placed into service projects representing 536 MWs of new nuclear generation at a cost of $1,436 million, which has been capitalized to property, plant and equipment on Exelon s and Generation s Consolidated Balance Sheets.

Nuclear Waste Storage and 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, 2015, Generation had approximately 75,800 SNF assemblies (18,800 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 16 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, in which on-site dry cask storage will be in operation at Clinton in 2016 and is projected to be in operation at Three Mile Island in 2023. 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 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

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

Generation 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 all its stations to stage for shipping campaigns and store, as needed, Class B and Class C LLRW. Generation has a contract through 2032 to ship Class B

Table of Contents

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 each station 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 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 23 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 12 Fair Value of Financial Assets and Liabilities and Note 16 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Generation s NDT funds and its decommissioning obligations.

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 16 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.

Table of Contents

Fossil and Renewable Facilities (including Hydroelectric)

Generation has ownership interests in 13,281 MW of capacity in fossil and renewable generating facilities currently in service. Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) jointly owned facilities that include Wyman; (2) an ownership interest through an equity method investment in Sunnyside; (3) certain wind project entities with minority interest owners; and (4) an ownership interest in the Albany Green Energy, LLC project entity, 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. In 2015, 2014 and 2013, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 8%, 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. On December 22, 2015, FERC issued a new 40-year license for Muddy Run. The license term expires on December 1, 2055. Based on the FERC procedural schedule, the FERC licensing process was not completed prior to the expiration of Conowingo s license on September 1, 2014. FERC is required to issue an annual license for a facility until the new license is issued. On September 10, 2014, FERC issued an annual license for Conowingo, effective as of the expiration of the previous license. If FERC does not issue a new license prior to the expiration of annual license, the annual license 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 and fossil projects, and delay in start-up insurance for its renewable and fossil projects currently under construction. Generation does not purchase business interruption insurance for its wholly owned fossil and hydroelectric operations, unless required by financing agreements; see Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on 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.

Table of Contents

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, 2015:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic	16	2016 - 2032	805
Midwest	7	2016 - 2022	1,536
New England	8	2016 - 2017	650
ERCOT	5	2020 - 2031	1,501
Other Power Regions	12	2016 - 2030	2,927
Total	48		7,419

	2016	2017	2018	2019	2020
Capacity Expiring (MW)	586	1,761	101	627	980

Fuel

The following table shows sources of electric supply in GWh for 2015 and 2014:

	Source of Electric Supply	
	2015	2014
Nuclear [(a)]	175,474	166,454
Purchases non-trading portfolio [(b)]	61,592	48,200
Fossil (primarily natural gas)	14,937	26,324
Renewable [(c)]	5,982	6,429
Total supply	257,985	247,407

(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 2015 and 2014 includes physical volumes of 33,415 GWh and 25,053 GWh, respectively, for CENG.

(b) Purchased power for 2015 and 2014 includes physical volumes of 0 GWh and 5,346 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 after April 1, 2014.

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

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 2018. Generation s contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2018. All of Generation s enrichment requirements have been contracted through 2020. Contracts for fuel fabrication have been obtained through 2022. 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.

Table of Contents

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 13 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 in the market 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 may purchase more than the energy demanded by its customers. Generation then sells this open position, along with capacity not used to meet customer demand, in the wholesale electricity markets. Where necessary, Generation also purchases transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs in markets without an organized RTO. Generation also incorporates contingencies into its planning for extreme weather conditions, including potentially reserving capacity to meet summer loads at levels representative of warmer-than-normal weather conditions. 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 2016 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. As of December 31, 2015, the percentage of expected generation hedged for the major reportable segments was 90%-93%, 60%-63% and 28%-31% for 2016, 2017, and 2018, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation.

17

Table of Contents

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, 2015, 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
2016	$ 262	$ 229	$ 15	$ 506
2017	197	269	21	487
2018	92	115	23	230
2019	97	34	24	155
2020	40	1	16	57
Thereafter	221	1	35	257
Total	$ 909	$ 649	$ 134	$ 1,692

(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, 2015, 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, 2015, capacity offsets were $146 million, $149 million, $150 million, $151 million, $142 million, and $462 million for years 2016, 2017, 2018, 2019, 2020, and thereafter, respectively. Expected payments include certain fixed capacity charges which may be reduced based on plant availability.

(b) The table excludes renewable energy purchases that are contingent in nature.

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

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 2016 are as follows:

(in millions)	
Nuclear fuel [a][b]	$ 1,150
Growth	1,350
Production plant [b]	950
Renewable energy projects	25
Other	125

Total	$ 3,600

(a) Includes Generation s share of the investment in nuclear fuel for the co-owned Salem plant.
(b) Includes the CENG units on a fully consolidated basis.

Table of Contents

ComEd

ComEd is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to retail 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 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 2016 to 2066. ComEd anticipates working with the appropriate governmental bodies to extend or replace the franchise agreements prior to expiration.

PECO

PECO is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission 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 related to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of PECO s business. PECO is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of PECO s business and by the U.S. Department of Transportation related 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 has the necessary authorizations to provide regulated electric and natural gas distribution services 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.

BGE

BGE is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission 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 related to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of BGE s business. BGE is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of BGE s business and by the U.S. Department of Transportation related 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.

19

Table of Contents

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.

ComEd, PECO and BGE

Utility Operations

Service Territories. The following table presents the size of retail service territories, populations of each retail service territory and the number of retail customers within each retail service territory for ComEd, PECO and BGE as of December 31, 2015:

	Retail Service Territories (in square miles)			Retail Service Territory Population (in millions)			Number of Retail Customers (in millions)		
	Total	Electric	Natural gas	Total	Electric	Natural gas	Total	Electric	Natural gas
ComEd	11,400	11,400	n/a	9.0[(a)]	9.0	n/a	3.8	3.8	n/a
PECO	2,100	1,900	1,900	4.6[(b)]	4.0	3.1	2.1	1.6	0.5
BGE	2,300	2,300	800	3.0[(c)]	3.0	1.7	1.3	1.3	0.7

(a) Includes approximately 2.8 million in the city of Chicago.
(b) Includes approximately 1.6 million in the city of Philadelphia.
(c) Includes approximately 0.6 million in the city of Baltimore.

Peak Deliveries. ComEd, PECO and BGE electric sales and peak load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. For PECO and BGE, natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating.

The following table summarizes peak deliveries for ComEd, PECO and BGE for electric and gas deliveries during peak demand months as of December 31, 2015:

	Electric Peak Deliveries (in GW)				Natural Gas Peak Deliveries (in mmcfs)	
	Summer peak date	Summer deliveries	Winter peak date	Winter deliveries	Winter peak date	Winter deliveries
ComEd	7/20/2011	23.75	1/6/2014	16.51	n/a	n/a
PECO	7/22/2011	8.98	1/7/2014	7.17	2/15/2015	777
BGE	7/21/2011	7.23	2/20/2015	6.71	2/19/2015	777

Electric and Natural Gas Distribution Services. ComEd, PECO and BGE are allowed to recover reasonable costs and fair and prudent capital expenditures associated with electric and natural gas distribution services and earn a return on those capital expenditures, subject to commission approval. ComEd recovers costs through a performance-based rate formula, pursuant to EIMA. ComEd is required to file an update to the performance-based rate formula on an annual basis. PECO s and BGE s electric and gas distribution costs are recovered through traditional rate case proceedings. In certain instances, ComEd, PECO and BGE use specific recovery mechanisms as approved by the ICC, PAPUC, and MDPSC, respectively.

Table of Contents

Through the ICC, ComEd is obligated to deliver electricity to customers in their respective service territories and also retain significant default service obligations (referred to as POLR) to provide electricity to certain groups of customers in their respective service areas who do not choose a competitive electric generation supplier. Through the PAPUC and MDPSC, PECO and BGE, respectively, are obligated to deliver electricity and natural gas to customers in their respective service territories and also retain significant default service obligations (referred to as DSP and SOS for electric and PGC and MBR for natural gas, respectively) to provide electricity or natural gas to certain groups of customers in their respective service areas who do not choose a competitive electric generation supplier or a competitive natural gas supplier. ComEd is permitted to recover electric costs, and PECO and BGE are permitted to recover electric and natural gas procurement costs from retail customers. Therefore, fluctuations in electric and natural gas procurement costs have no impact on electric and natural gas revenue net of purchased power and fuel expense.

ComEd customers have the choice to purchase electricity, and PECO and BGE customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. The customer s choice of suppliers does not impact the volume of deliveries, but affects revenues collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and gas revenue net of purchased power and fuel expense. For those customers that choose a competitive electric generation or natural gas supplier, ComEd, PECO and BGE may act as the billing agent but do not record revenues or purchased power and fuel expense related to the electric and natural gas procurement costs. ComEd, PECO and BGE remain the distribution service providers for all customers in their respective service territories and charge a regulated rate for distribution service.

Retail customers participating in customer choice programs, and retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of GWh and mmcf sales, respectively) for ComEd, PECO and BGE consisted of the following at December 31, 2015, 2014 and 2013:

	December 31, 2015					
	Number of retail customers		% of total retail customers		Deliveries as a % of retail sales (for the year ended)	
	Electric	Natural gas	Electric	Natural gas	Electric	Natural gas
ComEd [(a)]	1,655,400	n/a	42%	n/a	76%	n/a
PECO	563,400	81,100	35%	16%	70%	25%
BGE	343,000	154,000	27%	23%	61%	56%

	December 31, 2014					
	Number of retail customers		% of total retail customers		Deliveries as a % of retail sales (for the year ended)	
	Electric	Natural gas	Electric	Natural gas	Electric	Natural gas
ComEd	2,426,900	n/a	63%	n/a	80%	n/a
PECO	546,900	78,400	34%	16%	70%	22%
BGE	364,000	161,000	29%	25%	60%	53%

	December 31, 2013					
	Number of retail customers		% of total retail customers		Deliveries as a % of retail sales (for the year ended)	
	Electric	Natural gas	Electric	Natural gas	Electric	Natural gas
ComEd	2,630,200	n/a	68%	n/a	81%	n/a
PECO	531,500	66,400	34%	13%	68%	19%
BGE	399,000	172,000	32%	26%	61%	54%

(a) In September 2015, the City of Chicago discontinued its participation in the customer choice program and began purchasing its electricity from ComEd. Approximately 670,000 customers were impacted by the City of Chicago s decision which resulted in the reduction in the number of customers participating in customer choice programs in 2015.

21

Table of Contents

Procurement-Related Proceedings. ComEd s, PECO s and BGE s electric supply for its customers is primarily procured through contracts as required by the ICC, PAPUC and MDPSC, respectively. ComEd, PECO and BGE procure electricity supply from various approved bidders, including Generation. Charges incurred for electric supply procured through contracts with Generation are included in Purchased power from affiliates on ComEd s, PECO s and BGE s Statement of Operations and Comprehensive Income.

PECO s and BGE s natural gas supplies are purchased from a number of suppliers for terms of up to three years. PECO and BGE have annual firm supply from transportation contracts of 132,000 mmcf and 128,000 mmcf, respectively. In addition, to supplement gas supply at times of heavy winter demands and in the event of temporary emergencies, PECO and BGE have available storage capacity from the following sources:

	Peak Natural Gas Sources (in mmcf)		
	Liquefied Natural Gas Facility	**Propane-Air Plant**	**Underground Storage Service Agreements** [a]
PECO	1,200	150	18,000
BGE	1,055	546	22,000

(a) Natural gas from underground storage represents approximately 28% and 31% of PECO and BGE s 2015-2016 heating season planned supplies, respectively.

PECO and BGE have long-term interstate pipeline contracts and also participate 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 the utilities and customers. PECO and BGE make these sales as part of a program to balance its supply and cost of natural gas.

Energy Efficiency Programs. ComEd, PECO and BGE are also allowed to recover costs associated with energy efficiency and demand response programs. Each commission approved program seeks to meet mandated electric consumption reduction targets and implement demand response measures to reduce peak demand. The programs are designed to meet standards required by each respective regulatory agency.

Capital Investment. ComEd s, PECO s and BGE s businesses are capital intensive and requires significant investments, primarily in electric transmission and distribution and natural gas transportation and distribution facilities, to ensure the adequate capacity, reliability and efficiency of its system. ComEd s, PECO s and BGE s most recent estimates of capital expenditures for plant additions and improvements for 2016 are $2,425 million, $675 million and $825 million, respectively.

ComEd, PECO and BGE each have ICC, PAPUC and MDPSC, respectively, approved smart meter and smart grid deployment programs to enhance their distribution systems. The following table summarizes ComEd s smart meter and PECO s and BGE s smart meter and smart grid technology spending and meter installations as of December 31, 2015:

	December 31, 2015					
	Total Spend from Inception to Date		**Total Meters to be Installed**		**Meters Installed to Date**	
			(in millions)			
	Projected	**Actual**	**Electric**	**Natural gas**	**Electric**	**Natural gas**

ComEd [a]	$ 2,615	$ 1,526	4.0	n/a	2.0	n/a
PECO [b]	818	803	1.7	0.5	1.7	0.5
BGE [c]	527	512	1.3	0.7	1.2	0.6

(a) 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. These amounts represent capital expenditures associated with ComEd s commitment.
(b) PECO will seek recovery of costs associated with PECO s gas AMI through the traditional rate case process.
(c) BGE is seeking recovery of its smart grid initiative costs as part of its 2015 electric and gas distribution rate case. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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). PJM 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 and BGE s transmission rates are established based on a formula that was approved by FERC in January 2008 and April 2006, respectively. 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 s customers are charged for PECO s PJM retail transmission services on a full and current basis through a Transmission Service Charge (applicable to default service only) and through a Non-Bypassable Transmission Charge (applicable to all distribution customers) in accordance with PECO s approved distribution rates.

See Note 3 Regulatory Matters, Note 25 Segment Information of the Combined Notes to Consolidated Financial Statements and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for further information.

Employees

As of December 31, 2015, Exelon and its subsidiaries had 29,762 employees in the following companies, of which 9,649 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	1,688	102	2,424	4,214	14,512
ComEd	3,996			3,996	6,765
PECO		1,327		1,327	2,641
BGE					3,293
Other [(d)]	69		43	112	2,551
Total	5,753	1,429	2,467	9,649	29,762

(a) A separate CBA between ComEd and IBEW Local 15 covers approximately 61 employees in ComEd s System Services Group and was extended to April 1, 2016. Generation s and ComEd s separate CBAs with IBEW Local 15 expires in 2019.
(b) 1,327 PECO craft and call center employees in the Philadelphia service territory are covered by CBAs with IBEW Local 614, both expiring in 2021. Additionally, Exelon Power, an operating unit of Generation, has an agreement with IBEW Local 614, which expires in 2016 and covers 102 employees.
(c) During 2015, Generation finalized its CBA with Clinton Local 51 which will expire in 2020; its two CBAs with Local 369 at Mystic 7 and Mystic 8/9, both expiring in 2020; and four Security Officer unions at Braidwood, Byron, Clinton and TMI, all expiring between 2018 and 2021, respectively. 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, Generation finalized its CBA with the Security Officer union at Oyster Creek, expiring in 2016; as well as two other 3-year agreements: New England ENEH, UWUA Local 369, which will expire in 2017; and New Energy IUOE Local 95-95A, which will expire in 2016.
(d) Other includes shared services employees at BSC.

Environmental Regulation

General

Exelon, Generation, ComEd, PECO and BGE are subject to comprehensive and complex legislation regarding environmental matters by the federal government and various state and local jurisdictions in which they operate their facilities. The Registrants are also subject to regulations administered by the 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 of Directors has delegated to its corporate governance committee the 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 of Directors has also delegated to its Generation Oversight Committee the 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 of Directors, oversee environmental, health and safety issues related to ComEd, PECO and BGE.

Air Quality

Air quality regulations promulgated by the EPA and the various state and local environmental agencies in Illinois, Maryland, Massachusetts, New York, Pennsylvania and Texas in accordance with the Federal Clean Air Act impose restrictions on emission of particulates, sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury and other pollutants and require permits for operation of emissions sources. Such permits have been obtained by Exelon s subsidiaries and must be renewed periodically. The Clean Air Act establishes a comprehensive and complex national program to substantially reduce 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.

Table of Contents

Water Quality

Under the Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the 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 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 Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, Ginna, Gould Street, Handley, Mountain Creek, Mystic 7, Nine Mile Point Unit 1, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill.

On October 14, 2014, the 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 to minimize adverse impacts on aquatic life, followed by an implementation period for the selected technology. 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.

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 generating facilities and its future results of operations, cash flows, 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 potential impact of the rule has been significantly reduced since the final rule does not mandate cooling towers as a national standard and sets forth technologies that are presumptively compliant, 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. The Ginna and Nine Mile Point Unit 1 power generation facilities received renewals of their state water discharge permits in 2014.

Salem. In June 2001, the NJDEP issued a renewed NPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water system. In February 2006, PSEG filed a renewal application with the NJDEP allowing Salem to continue operating under its existing NPDES permit until a new permit was issued. On June 30, 2015, NJDEP issued a draft NPDES permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with certain required system modifications. The draft permit was subject to a public notice and comment period and the NJDEP may make revisions before issuing the final permit expected during the first half of 2016.

Table of Contents

Solid and Hazardous Waste

CERCLA provides for immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances into the environment and authorizes the 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 EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with an EPA-directed cleanup, may voluntarily settle with the 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 EPA, state agencies and/or other responsible parties under CERCLA and RCRA with respect to a number of sites, including MGP sites, or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third-party.

See Note 23 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 2016 at Exelon for compliance with environmental remediation related to contamination at former MGP sites and other gas purification sites is expected to total $38 million, consisting of $32 million and $6 million respectively, at ComEd and PECO.

Generation s environmental liabilities primarily arise from contamination at current and former generation and waste storage facilities. As of December 31, 2015, 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 23 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.

Table of Contents

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 (CO2e) emitted per unit of electricity generated, is among the lowest in the industry. Exelon does produce GHG emissions, primarily at its natural gas-fired generating plants; CO2, methane and nitrous oxide are all emitted in this process, with CO2 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 2015, 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 (SF6) 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 fossil fuel generation of electricity used to power its facilities. Despite its focus on low-carbon generation, Exelon believes its operations could be significantly affected by the possible physical risks of climate change and by mandatory programs to reduce GHG emissions. See ITEM 1A. RISK FACTORS for information regarding the market and financial, regulatory and legislative, and operational risks associated with climate change.

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

International Climate Change Regulation. At the international level, the United States is a Party to the United Nations Framework Convention on Climate Change (UNFCCC). The Parties to the UNFCCC adopted the Paris Agreement at the 21st session of the UNFCCC Conference of the Parties (COP 21) on December 12, 2015. The Paris Agreement defines the UNFCCC s objective of limiting the global temperature increase to 1.5°C above pre-industrial levels. All Parties are required to develop their own national emission reductions and to update those reductions at least every five years. The Developed Country Parties, including the United States, are required to take the lead by undertaking economy-wide absolute emission reduction targets. The United States had previously submitted its national emission reductions to achieve a 2020 target of reducing net emissions in the range of 17% below the 2005 level and to achieve net greenhouse gas emission reductions of 26% 28% below the 2005 level by 2025. The United States has indicated that it intends to achieve these reductions through a variety of mechanisms, including regulations to cut carbon pollution from new and existing power plants. The Paris Agreement will enter into force on the thirtieth day after the date on which at least 55 Parties accounting for at least an estimated 55% of total global greenhouse gas emissions have ratified the Agreement.

Federal Climate Change Legislation and Regulation. It is highly uncertain that 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 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

Table of Contents

Section 111 of the Clean Air Act. Pursuant to the Climate Action Plan, President Obama directed the EPA to regulate new and modified fossil fired generating units under Section 111(b) of the Clean Air Act. The EPA finalized the rule in August 2015, and the final rule has been challenged in the U.S. Court of Appeals for the District of Columbia.

Under the President s memorandum, the EPA was also required to finalize a rule to establish CO_2 emission reduction requirements for existing fossil-fuel generating stations under Section 111(d) of the Clean Air Act. The final rule, known as the Clean Power Plan, became effective on December 22, 2015. The rule sets GHG emission reduction targets for each state, with reductions beginning in 2022, and the target achieved by 2030. States must submit an implementation plan to the EPA by September 2016, unless granted an extension of up to two years. States are granted latitude to select from a number of compliance options, which are designed to achieve the reductions in the most cost-effective manner. The final rule has been challenged in the U.S. Court of Appeals for the District of Columbia. On February 9, 2015, the U.S. Supreme Court issued a stay of the Clean Power Plan until the disposition of the petitions challenging the rule now before the Court of Appeals, and, if such petitions are filed in the future, before the U.S. Supreme Court. While the ultimate impact of the Clean Power Plan rule is expected to be favorable, Exelon and Generation cannot at this time predict to what extent the states actions to comply with the Clean Power Plan s emission reduction targets will impact their future financial position, results of operations and cash flows.

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 from 2015 through 2020. Included in the 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 available for purchase at auction. (CCR trigger prices are $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 greenhouse gas reduction strategy with 42 recommendations 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 was required to submit a December 2015 report to the Governor and General Assembly

Table of Contents

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.

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.

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 to cumulatively increase this percentage to at least 10% by June 1, 2015 and 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, 2015, 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.

The AEPS Act became effective for PECO on January 1, 2011. During 2015, PECO was required to supply approximately 5.0% of electric energy generated from Tier I alternative energy resources (including solar, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, fuel cells, biomass energy, coal mine methane and black liquor generated within Pennsylvania), as measured in AECs, through May 31, 2015 and subsequently 5.5% beginning June 1, 2015 and continuing through May 31, 2016. PECO was also required to supply 6.2% of electric energy generated from Tier II alternative energy resources (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), as measured in AECs, through May 31, 2015 and subsequently 8.2% beginning June 1, 2015 and continuing through May 31, 2016. 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

Table of Contents

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 2015, 10.5% was required from Tier 1 renewable sources, including at least 0.5% 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 of the Combined Notes to Consolidated Financial Statements for additional information.

Executive Officers of the Registrants as of February 10, 2016

Exelon

Name	Age	Position	Period
Crane, Christopher M.	57	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.	50	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.	55	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.	57	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012

Table of Contents

Name	Age	Position	Period
Adams, Craig L.	63	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Butler, Calvin G.	46	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.	62	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
		Executive Vice President, Finance and Legal, Exelon	2009 - 2012
Thayer, Jonathan W.	44	Senior Executive Vice President and Chief Financial Officer, Exelon	2012 - Present
		Senior Vice President and Chief Financial Officer, Constellation Energy; Treasurer, Constellation Energy	2008 - 2012
Aliabadi, Paymon	53	Executive Vice President and Chief Enterprise Risk Officer, Exelon	2013 - Present
		Managing Director, Gleam Capital Management	2012 - 2013
		Principal and Managing Director, Gunvor International	2009 - 2011
DesParte, Duane M.	52	Senior Vice President and Corporate Controller, Exelon	2008 - Present

Generation

Name	Age	Position	Period
Cornew, Kenneth W.	50	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	51	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.	55	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

Table of Contents

Name	Age	Position	Period
Hanson, Bryan C.	50	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	53	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.	49	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	49	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

ComEd

Name	Age	Position	Period
Pramaggiore, Anne R.	57	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
Donnelly, Terence R.	55	Executive Vice President and Chief Operating Officer, ComEd	2012 - Present
		Executive Vice President, Operations, ComEd	2009 - 2012
Trpik Jr., Joseph R.	46	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.	53	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2010 - Present
		Senior Vice President, Exelon	2009 - 2010
Marquez Jr., Fidel	54	Senior Vice President, Governmental and External Affairs, ComEd	2012 - Present
		Senior Vice President, Customer Operations, ComEd	2009 - 2012

Table of Contents

Name	Age	Position	Period
Brookins, Kevin B.	54	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	51	Senior Vice President, Distribution Operations, ComEd	2010 - Present
		Vice President, Transmission and Substations, ComEd	2007 - 2010
Kozel, Gerald J.	43	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.	63	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Barnett, Phillip S.	52	Senior Vice President and Chief Financial Officer, PECO	2007 - Present
		Treasurer, PECO	2012 - Present
Innocenzo, Michael A.	50	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
Webster Jr., Richard G.	54	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
		Director of Rates and Regulatory Affairs	2007 - 2012
Murphy, Elizabeth A.	56	Vice President, Governmental and External Affairs, PECO	2012 - Present
		Director, Governmental & External Affairs, PECO	2007 - 2012
Jiruska, Frank J.	55	Vice President, Customer Operations, PECO	2013 - Present
		Director of Energy and Marketing Services, PECO	2010 - 2013
Diaz Jr., Romulo L.	69	Vice President and General Counsel, PECO	2012 - Present
		Vice President, Governmental and External Affairs, PECO	2009 - 2012
Bailey, Scott A.	39	Vice President and Controller, PECO	2012 - Present
		Assistant Controller, Generation	2011 - 2012
		Director of Accounting, Power Team	2007 - 2011

Table of Contents

BGE

Name	Age	Position	Period
Butler, Calvin G.	46	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.	48	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.	43	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.	54	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
Gahagan, Daniel P.	62	Vice President and General Counsel, BGE	2007 - Present
Bauer, Matthew N.	39	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
Núñez, Alexander G.	44	Vice President, Governmental and External Affairs, BGE	2013 - Present
		Director, State Affairs, BGE	2012 - 2013
		Director, State Affairs, Constellation Energy	2006 - 2012

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 Enterprise 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 Enterprise 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 could adversely affect one or more of the Registrants results of operations or 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 could adversely affect its performance or financial condition in the future.

Exelon s financial conditions 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 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 could 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.

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 could negatively affect its results of operations or 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.

Table of Contents

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 could 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, could often exceed demand during some hours of the day, resulting in loss of revenue for base-load generating plants. Increased supply in excess of demand is furthered by the continuation of RPS mandates and subsidies for renewable energy.

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 wholesale generators (including Generation) use their retail operations to hedge generation output. Increased or more aggressive competition could 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 or 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 result of operations through accelerated depreciation expense, impairment charges related to inventory that cannot be used at other nuclear units and cancellation of in-flight capital projects, accelerated amortization of plant specific nuclear fuel costs, severance costs, accelerated asset retirement obligation expense relate to future decommissioning activities, and additional funding of decommissioning costs, which can 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 or financial positions. See Note 9 Implications of Potential Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

In addition to price fluctuations, Generation is exposed to other risks in the power markets that are beyond its control and could 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 could 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 could 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 could 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, distributed generation 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, cash flows or financial positions 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 could decrease the value of NDT funds and employee benefit plan assets and could 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 could 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 could fall below the Registrants projected return rates. A decline in the market value of the NDT fund investments could 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 could 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 within the NDT funds and benefit plan assets, and are unable to manage the related benefit plan liabilities, their results of operations, cash flows or financial positions could be negatively impacted.

Unstable capital and credit markets and increased volatility in commodity markets could 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 negatively impact the Registrants results of operations, cash flows or financial positions. (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 could 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, 2015, approximately 25%, or $2.1 billion of the Registrants available credit facilities were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.9 billion was available as of December 31, 2015. There were no borrowings under the Registrants credit facilities as of December 31, 2015. See Note 14 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 or 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 could 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. Generation has project-specific financing arrangements and must meet the requirements of various agreements relating to those financings. Failure to meet those arrangements could give rise to a project-specific financing default which, if not cured or waived, could result in the specific project being required to repay the associated debt or other borrowings earlier than otherwise anticipated, and if such repayment were not made, the lenders or security holders would generally have rights to foreclose against the project assets and related collateral.

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 could 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 conclude 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 limit 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.

Table of Contents

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 could 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 supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. Natural gas and oil are procured for generating plants through annual, short-term and spot-market purchases. The supply markets for nuclear fuel, natural gas and oil are subject to price fluctuations, availability restrictions and counterparty default that could negatively affect the results of operations or 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 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 could 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 could have on its business, operating results, cash flows or financial positions.

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 could expose Generation to volatility in future results of operations.

Financial performance and load requirements could 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 could 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 or 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 could be on its results of operations or cash flows.

1999 sale of fossil generating assets. The IRS has challenged Exelon s 1999 tax position on its like-kind exchange transaction. Exelon and the IRS failed to reach a settlement on the like-kind exchange position and Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court and the trial took place in August 2015. 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, 2015, 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 $760 million, of which approximately $280 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 approximately $90 million of penalties for a substantial understatement of tax. The timing effects of the final resolution of the like-kind exchange matter are unknown. See Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Tax reserves. 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 could be subject to challenge by the tax authorities. See Notes 1 Significant Accounting Policies and Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

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

41

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 could 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 or cash flows. Also, ComEd s, PECO s and BGE s cash flows could 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, could result in an increase in the number of uncollectible customer balances, which would negatively impact ComEd s, PECO s and BGE s results of operations or cash flows. Generation s customer-facing energy delivery 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-facing energy delivery activities, economic downturn impacts could negatively affect Generation s results of operations or cash flows. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for further discussion of the Registrants credit risk.

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

Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. 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. 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 could 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 could have detrimental effects on ComEd s, PECO s and BGE s results of operations or cash flows. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and could 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 could require greater resources to meet its contractual commitments. Extreme weather conditions or storms could 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 could impact Generation s ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, could 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.

Table of Contents

Certain long-lived assets and other assets recorded on the Registrants statements of financial position could 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 positions. Specifically, long-lived assets account for 60%, 56%, 66%, 69% and 80% of total assets for Exelon, Generation, ComEd, PECO and BGE, respectively, as of December 31, 2015. In addition, Exelon and Generation have significant balances related to unamortized energy contracts. See Note 11 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, 2015 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 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 11 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 could 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

Table of Contents

distribution infrastructure projects. These operational systems and infrastructure have been in service for many years. Equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond the Registrants control, and could require significant expenditures to operate efficiently. The Registrants results of operations, financial conditions, 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 could 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 could 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 conditions, 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 or financial positions. 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 could 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 or financial positions.

Regulatory and Legislative Factors

The Registrants generation and energy delivery businesses are highly regulated and could be subject to regulatory and legislative actions that adversely affect their operations or financial results. 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 or 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.

44

Table of Contents

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 and understand rule 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 negatively impact their results of operations, cash flows or financial positions.

Regulatory and legislative developments related to climate change and RPS could also significantly affect Exelon s and Generation s results of operations, cash flows or financial positions. Various legislative and regulatory proposals to address climate change through GHG emission reductions, if enacted, could result in increased costs to entities that generate electricity through carbon-emitting fossil fuels, which could increase the market price at which all generators in a region, including Generation, may sell their output, thereby increasing the revenue Generation could realize from its low-carbon nuclear assets. However, national regulation or legislation addressing climate change through an RPS could also increase the pace of development of wind energy facilities in the Midwest, which could put downward pressure on wholesale market prices for electricity from Generation s Midwest nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation s nuclear assets under a carbon constrained regulatory regime that might exist in the future. 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 could 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 65% 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.

Table of Contents

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.

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 accepts 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

Table of Contents

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 could 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 could 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 could 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. On June 30, 2015, NJDEP issued a draft NPDES permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The draft permit is subject to a public notice and comment period after which the NJDEP may make revisions before issuing the final permit expected during the first half of 2016.

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 could 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 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Table of Contents

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 could 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 could 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 default service obligations, referred to as POLR, DSP and SOS for ComEd, PECO and BGE, respectively, 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 or 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, 2015, 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 and Comprehensive Income. 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, 2015, the gain (loss) could have been as much as $(2.5) billion, $978 million and $559 million (before taxes) as a result of the elimination of ComEd s, PECO s and BGE s regulatory assets and liabilities, respectively. Further, Exelon would record a charge against OCI (before taxes) of up to $2.5 billion and $634 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 $47 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 11 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 could 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 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

Table of Contents

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 could 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 could require ComEd, PECO and BGE to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards.

See Note 3 Regulatory Matters and Note 23 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 negatively impact their results of operations, cash flows or financial positions. (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 23 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 could 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 could require a substantial increase in capital expenditures or could result in increased operating or decommissioning costs and significantly affect Generation s results of operations or financial positions. Events at nuclear plants owned by others, as well as those owned by Generation, could cause the NRC to initiate such actions.

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 could 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 23 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 or 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 could 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 could 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 could 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 could negatively impact the Registrants 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

51

Table of Contents

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 could 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 could damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses.

Generation s financial performance could 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, could have a significant impact on Generation s results of operations. When refueling outages 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 could 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 could require significant time and expense. Generation could choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, Generation could 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 could 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 positions. 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 could 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, could 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 positions. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, owned by others or Generation, could result in increased regulation and reduced public support for nuclear-fueled energy and significantly affect Generation s results of operations or financial positions.

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 $13.5 billion limit for a single incident.

Table of Contents

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 23 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 units that have been retired and units that are within five years of retirement) 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 could 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 could be negatively affected and Exelon s and Generation s results of operations or financial positions 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 or financial positions could 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 could have to seek remedies available under the ASA to reduce the risk of default by ZionSolutions and its parent. See Note 16 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

Generation s financial performance could 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 September 1, 2016, and the license for the Muddy Run Pumped Storage Project expires on December 1, 2055. FERC is required to issue annual licenses for the facilities until a final determination is made on the license renewal. 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 could also lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, conditions could be imposed as part of the license renewal process that could adversely affect operations, could require a substantial increase in capital expenditures or could result in increased operating costs and significantly affect Generation s results of operations or financial positions. Similar effects could 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 could 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 results of operations, cash flows or financial conditions could be negatively impacted. 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 negatively impacted. 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 negatively impacted. 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, could 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 could 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 or cash flows. See Note 23 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.

ComEd s, PECO s and BGE s respective ability to deliver electricity, their operating costs and their capital expenditures could be negatively impacted 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.

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

The Registrants face physical security and cybersecurity risks as the owner-operators of generation, transmission and distribution facilities and as a participant in commodities trading. Threat sources continue to seek to exploit potential vulnerabilities in the electric and natural gas utility industry associated with protection of sensitive and confidential information, grid infrastructure and other energy infrastructures, and such attacks and disruptions, both physical and cyber, are becoming increasingly sophisticated and dynamic. Continued implementation of advanced digital technologies increase the potentially unfavorable impacts of such attacks. A security breach of the physical assets or information systems of the Registrants, their competitors, interconnected entities in 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, vendor, employee, trading or other confidential data. The risk of these system-related events and security breaches occurring continues to intensify, and while we have been, and will likely continue to be, subjected to physical and cyber-attacks, to date we have not experienced a material breach or disruption to our network or information systems or our service operations. However, as such attacks continue to increase in sophistication and frequency, we may be unable to prevent all such attacks in the future. 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. Moreover, the amount and scope of insurance we maintain against losses resulting from any such events or security breaches may not be sufficient to cover our losses or otherwise adequately compensate us for any disruptions to our business that may result. 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. In addition, new or updated security regulations or unforeseen threat sources 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.

Failure to attract and retain an appropriately qualified workforce could 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, could 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, could 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 impacted.

The Registrants could make investments in new business initiatives, including initiatives mandated by regulators, and markets that may not be successful, and acquisitions could 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 could 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 could 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 could 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, cybersecurity 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 could encounter difficulties in satisfying the conditions for the completion of the Merger and the Merger could 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 receipt of regulatory approvals required to consummate the Merger, (2) the expiration or termination of the applicable waiting period under the HSR Act and (3) 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, the Merger Agreement provides that either Exelon or PHI could terminate the Merger Agreement if the merger is not completed by October 28, 2015. Exelon and PHI have agreed, among other things, that they will not exercise their rights to terminate the Merger Agreement before March 4, 2016, except under limited circumstances.

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 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 various regulatory authorities, including the DCPSC and the public utility commissions or similar entities in certain states in which the companies operate. The Merger has been approved by the Delaware Public Service Commission (DPSC), the Maryland Public Service Commission (MDPSC), the New Jersey Board of Public Utilities (NJBPU) and the Virginia State Corporation Commission. Approval of the Merger by the MDPSC is subject to appeals by the Maryland Office of People s Counsel, the Sierra Club/Chesapeake Climate Action Network and Public Citizen, Inc. in the Circuit Court of Queen Anne s County, and the approval by the NJBPU expires on June 30, 2016. The HSR Act waiting period applicable to the Merger expired on December 2, 2015. The Merger remains subject to approval by the DCPSC. 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 the filings that have been made with the DCPSC and other regulatory commissions. The conditions of approval of the Merger by the DCPSC will trigger the most favored nation provisions in the approvals of the Merger by the DPSC, MDPSC, and the NJBPU.

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 unacceptable. 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).

Failure to obtain regulatory approval could 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 $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. In these circumstances, Exelon will also be required to reimburse PHI for up to $40 million of its documented out-of-pocket expenses for the Merger.

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

If the Merger is not completed, the ongoing businesses of Exelon could be negatively impacted 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 a termination fee of up to $180 million payable by Exelon to PHI under certain circumstances; and

- the share price of Exelon could 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 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, until the closing of the Merger, Exelon will be required to pay financing costs without having realized any benefits from the Merger during the period of delay. Exelon will also incur transition costs related to formulating integration plans. 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.

58

Table of Contents

Exelon may not realize all the expected benefits of the Merger because of integration difficulties.

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 could 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; and
- difficulties in retention of key employees.

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

Uncertainty about the effect of the Merger on employees, suppliers and customers could have a negative impact on Exelon and/or PHI. These uncertainties could 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 could experience uncertainty about their future roles with the combined company. In addition, current and prospective Exelon and PHI employees could determine that they do not desire to work for the combined company for a variety of possible reasons. Moreover, the pendency of Merger regulatory-review proceedings has caused PHI to delay filing base rate cases on behalf of its utilities Pepco, ACE and Delmarva which have had a material impact to their results of operations and cash flows.

The Merger could 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 could 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.

Exelon is obligated to complete the Merger whether or not it has obtained the required financing.

Exelon intended to fund the cash consideration in the Merger using a combination of debt, cash from asset sales, the issuance of equity (including mandatory convertible securities). See Note 4 Mergers, Acquisitions, and Dispositions and Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information regarding the merger financing. Although Exelon had sufficient cash to fund the cash consideration in the Merger as of September 30, 2015, a $2.75 billion portion of the debt incurred to finance the cash consideration was subject to mandatory special redemption on December 31, 2015. On December 2, 2015, the holders of $1.9 billion of that debt exchanged those debt securities for new notes that extend the mandatory special redemption date from December 31, 2015 to June 30, 2016 (or later under some circumstances), and on December 2, 2015, Exelon redeemed $868 million of the debt. Exelon could be required to raise additional cash to fund the cash consideration in the Merger.

The combined company s assets, liabilities or results of operations could be negatively impacted 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 negatively impacted 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 negatively impact the combined company s future business, operating results, cash flows, financial conditions or prospects.

Exelon could 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 or financial positions.

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 approximately 90 days after the Merger closing date.

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 could 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.

Table of Contents

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

Prior to the completion of the Merger, Exelon and PHI could, 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 could choose to waive requirements of the Merger Agreement, including some conditions to closing of the Merger.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Exelon, Generation, ComEd, PECO and BGE

None.

Table of Contents

ITEM 2. PROPERTIES

Generation

The following table describes Generation s interests in net electric generating capacity by station at December 31, 2015:

Station [(a)]	Region	Location	No. of Units	Percent Owned [(b)]	Primary Fuel Type	Primary Dispatch Type [(c)]	Net Generation Capacity (MW) [(d)]
Braidwood	Midwest	Braidwood, IL	2		Uranium	Base-load	2,389
Byron	Midwest	Byron, IL	2		Uranium	Base-load	2,347
LaSalle	Midwest	Seneca, IL	2		Uranium	Base-load	2,320
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
Beebe	Midwest	Gratiot Co., MI	34		Wind	Base-load	82
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	20[(f)]
Marshall	Midwest	Lyon Co., MN	9	99	Wind	Base-load	19[(f)]
Norgaard	Midwest	Lincoln Co., MN	7	99	Wind	Base-load	9[(f)]
City Solar	Midwest	Chicago, IL	1		Solar	Base-load	9
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
Solar Ohio	Midwest	Toledo, OH	3		Solar	Base-load	3
Cowell	Midwest	Pipestone Co., MN	1	99	Wind	Base-load	2[(f)]
Southeast Chicago	Midwest	Chicago, IL	8		Gas	Peaking	296
Total Midwest							12,163
Limerick	Mid-Atlantic	Sanatoga, PA	2		Uranium	Base-load	2,317
Peach Bottom	Mid-Atlantic	Delta, PA	2	50	Uranium	Base-load	1,299[(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
Fair Wind	Mid-Atlantic	Garrett County, MD	12		Wind	Base-load	30
Solar Maryland MC	Mid-Atlantic	Various, MD	15		Solar	Base-load	27
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	10		Solar	Base-load	7
Solar Maryland 2	Mid-Atlantic	Various, MD	3		Solar	Base-load	7
Solar Federal	Mid-Atlantic	Trenton, NJ	1		Solar	Base-load	4
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
Perryman	Mid-Atlantic	Aberdeen, MD	6		Oil/Gas	Peaking	463[(h)]

Croydon	Mid-Atlantic	West Bristol, PA	8	Oil	Peaking	391
Handsome Lake	Mid-Atlantic	Kennerdell, PA	5	Gas	Peaking	268
Notch Cliff	Mid-Atlantic	Baltimore, MD	8	Gas	Peaking	118
Westport	Mid-Atlantic	Baltimore, MD	1	Gas	Peaking	116
Riverside	Mid-Atlantic	Baltimore, MD	3	Oil/Gas	Peaking	113[h]
Richmond	Mid-Atlantic	Philadelphia, PA	2	Oil	Peaking	98

Table of Contents

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
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	5
Total Mid-Atlantic							11,725
Whitetail	ERCOT	Webb County, TX	57		Wind	Base-load	91
Sendero	ERCOT	Jim Hogg and Zapata County, TX	39		Wind	Base-load	78
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
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							3,593
Solar Massachusetts	New England	Various, MA	18		Solar	Base-load	8
Holyoke Solar	New England	Various, MA	2		Solar	Base-load	4
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]
West 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							2,219
Nine Mile Point	New York	Scriba, NY	2	50.01	Uranium	Base-load	838[f][g]
Ginna	New York	Ontario, NY	1	50.01	Uranium	Base-load	288[f][g]
Solar New York	New York	Bethlehem, NY	1		Solar	Base-load	2
Total New York							1,128
AVSR	Other	Lancaster, CA	1		Solar	Base-load	242
Shooting Star	Other	Kiowa County, 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	34[f]
Solar Arizona	Other	Various, AZ	55		Solar	Base-load	33
Cassia	Other	Buhl, ID	14		Wind	Base-load	29
Wildcat	Other	Lovington, NM	13		Wind	Base-load	27
Sacramento PV Energy	Other	Sacramento, CA	4		Solar	Base-load	26
Sunnyside	Other	Sunnyside, UT	1	50	Waste Coal	Base-load	26[f]
Echo 2	Other	Echo, OR	10		Wind	Base-load	20

Tuana Springs	Other	Hagerman, ID	8	Wind	Base-load	17
California PV Energy	Other	Various, CA	37	Solar	Base-load	16
Greensburg	Other	Greensburg, KS	10	Wind	Base-load	13

Table of Contents

Station [(a)]	Region	Location	No. of Units	Percent Owned [(b)]	Primary Fuel Type	Primary Dispatch Type [(c)]	Net Generation Capacity (MW) [(d)]
Solar Georgia	Other	Various, GA	14		Solar	Base-load	12
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 California	Other	Various, CA	25		Solar	Base-load	10
Outback Solar	Other	Christmas Valley, OR	1		Solar	Base-load	5
Loess Hills	Other	Rock Port, MO	4		Wind	Base-load	5
Mohave Sunrise Solar	Other	Fort Mohave, AZ	1		Solar	Base-load	5
Denver Airport Solar	Other	Denver, CO	1		Solar	Base-load	4
Hillabee	Other	Alexander City, AL	3		Gas	Intermediate	722
Grande Prairie	Other	Alberta, Canada	1		Gas	Peaking	105
SEGS 4, 5, 6	Other	Boron, CA	3	4.2-12.2	Solar	Peaking	9[(f)]
Total Other							1,913
Total							32,741

(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 operations at the Perryman 2 (51 MWs) and Riverside 4 (74 MWs) units effective February 1, 2016 and May 31, 2016, respectively.

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.

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.

Table of Contents

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, 2015 were as follows:

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

ComEd s electric distribution system includes 35,419 circuit miles of overhead lines and 31,040 circuit miles of underground lines.

First Mortgage and Insurance

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

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

PECO

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

Transmission and Distribution

PECO s high voltage electric transmission lines owned and in service at December 31, 2015 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.

Table of Contents

PECO s electric distribution system includes 12,960 circuit miles of overhead lines and 9,218 circuit miles of underground lines.

Gas

The following table sets forth PECO s natural gas pipeline miles at December 31, 2015:

	Pipeline Miles
Transmission	30
Distribution	6,826
Service piping	6,220
Total	13,076

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 150 mmcf and a peaking capability of 25 mmcf/day. In addition, PECO owns 31 natural gas city gate stations and direct pipeline customer delivery points at various locations throughout its gas service territory.

First Mortgage and Insurance

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

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

BGE

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

Transmission and Distribution

BGE s high voltage electric transmission lines owned and in service at December 31, 2015 were as follows:

Voltage (Volts)	**Circuit Miles**
500,000	218
230,000	322
138,000	55
115,000	703

BGE s electric distribution system includes 9,190 circuit miles of overhead lines and 16,841 circuit miles of underground lines.

66

Table of Contents

Gas

The following table sets forth BGE s natural gas pipeline miles at December 31, 2015:

	Pipeline Miles
Transmission	161
Distribution	7,173
Service piping	6,225
Total	13,559

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

Property Insurance

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

Exelon

Security Measures

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

ITEM 3. LEGAL PROCEEDINGS

Exelon, Generation, ComEd, PECO and BGE

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Note 3 Regulatory Matters and Note 23 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.

Table of Contents

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, 2016, there were 919,924,742 shares of common stock outstanding and approximately 118,487 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:

	2015				2014			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 31.37	$ 34.44	$ 34.98	$ 38.25	$ 38.93	$ 36.26	$ 37.73	$ 33.94
Low price	25.09	28.41	31.28	31.71	33.07	30.66	33.11	26.45
Close	27.77	29.70	31.42	33.61	37.08	34.09	36.48	33.56
Dividends	0.310	0.310	0.310	0.310	0.310	0.310	0.310	0.310

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 2011 through 2015.

This performance chart assumes:

- $100 invested on December 31, 2010 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,					
	2010	**2011**	**2012**	**2013**	**2014**	**2015**
Exelon Corporation	$100	$108.67	$78.93	$76.16	$107.03	$83.31
S&P 500	$100	$98.88	$112.13	$145.33	$161.88	$160.70
S&P Utilities	$100	$114.25	$110.93	$120.64	$149.94	$137.36

Generation

As of January 31, 2016, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2016, there were 127,016,973 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, 2016, in addition to Exelon, there were 299 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

Table of Contents

PECO

As of January 31, 2016, 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, 2016, 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

Table of Contents

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.

Exelon s Board of Directors approved a revised dividend policy. The approved policy would raise our dividend 2.5% each year for the next three years, beginning with the June 2016 dividend. The Board will take formal action to declare the next dividend in the second quarter.

At December 31, 2015, Exelon had retained earnings of $12,068 million, including Generation s undistributed earnings of $2,701 million, ComEd s retained earnings of $978 million consisting of retained earnings appropriated for future dividends of $2,617 million, partially offset by $(1,639) million of unappropriated retained deficits, PECO s retained earnings of $780 million, and BGE s retained earnings of $1,320 million.

The following table sets forth Exelon s quarterly cash dividends per share paid during 2015 and 2014:

	2015				2014			
(per share)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Exelon	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310

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

	2015				2014			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$ 106	$ 106	$ 906	$ 1,356	$ 205	$ 205	$ 205	$ 31
ComEd	75	75	75	75	77	77	77	76
PECO	70	70	70	70	80	80	80	80

First Quarter 2016 Dividend. On January 26, 2016, the Exelon Board of Directors declared a first quarter 2016 regular quarterly dividend of $0.31 per share on Exelon s common stock payable on March 10, 2016, to shareholders of record of Exelon at the end of the day on February 12, 2016.

Table of Contents

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)	**2015**	**2014 [a]**	**2013**	**2012 [b]**	**2011**
Statement of Operations data:					
Operating revenues	$ 29,447	$ 27,429	$ 24,888	$ 23,489	$ 19,063
Operating income	4,409	3,096	3,669	2,373	4,479
Income from continuing operations	2,250	1,820	1,729	1,171	2,499
Net income	2,250	1,820	1,729	1,171	2,499
Net income attributable to common shareholders	2,269	1,623	1,719	1,160	2,495
Earnings per average common share (diluted):					
Income from continuing operations	$ 2.54	$ 1.88	$ 2.00	$ 1.42	$ 3.75
Net income	$ 2.54	$ 1.88	$ 2.00	$ 1.42	$ 3.75
Dividends per common share	$ 1.24	$ 1.24	$ 1.46	$ 2.10	$ 2.10
Average shares of common stock outstanding diluted	893	864	860	819	665

(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.

	December 31,				
(In millions)	**2015**	**2014**	**2013**	**2012**	**2011**
Balance Sheet data:					
Current assets	$ 15,334	$ 11,853	$ 9,562	$ 10,009	$ 5,713
Property, plant and equipment, net	57,439	52,170	47,330	45,186	32,570
Noncurrent regulatory assets	6,065	6,076	5,910	6,497	4,518
Goodwill	2,672	2,672	2,625	2,625	2,625
Other deferred debits and other assets	13,874	13,645	13,816	14,033	9,498
Total assets	$ 95,384	$ 86,416	$ 79,243	$ 78,350	$ 54,924
Current liabilities	$ 9,118	$ 8,762	$ 7,686	$ 7,734	$ 5,134
Long-term debt, including long-term debt to financing trusts	24,286	19,853	18,165	18,266	12,118
Noncurrent regulatory liabilities	4,201	4,550	4,388	3,981	3,627
Other deferred credits and other liabilities	30,457	29,118	26,064	26,552	19,570
Contingently redeemable noncontrolling interest [a]	28				
Preferred securities of subsidiary				87	87
Noncontrolling interest	1,308	1,332	15	106	3
BGE preference stock not subject to mandatory redemption	193	193	193	193	

Shareholders equity	25,793	22,608	22,732	21,431	14,385
Total liabilities and shareholders equity	$ 95,384	$ 86,416	$ 79,243	$ 78,350	$ 54,924

(a) Represents mezzanine equity related to contingently redeemable equity contributions made by a noncontrolling interest holder of one of Generation s subsidiaries. See Note 18 Contingently Redeemable Noncontrolling Interest for further information.

Table of Contents

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.

	For the Years Ended December 31,				
(In millions)	**2015**	**2014** [a]	**2013**	**2012** [b]	**2011**
Statement of Operations data:					
Operating revenues	$ 19,135	$ 17,393	$ 15,630	$ 14,437	$ 10,447
Operating income	2,275	1,176	1,677	1,113	2,875
Net income	1,340	1,019	1,060	558	1,771
Net income attributable to membership interest	1,372	835	1,070	562	1,771

(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.

	December 31,				
(In millions)	**2015**	**2014**	**2013**	**2012**	**2011**
Balance Sheet data:					
Current assets	$ 6,342	$ 7,311	$ 5,964	$ 6,211	$ 3,217
Property, plant and equipment, net	25,843	23,028	20,111	19,531	13,475
Other deferred debits and other assets	14,344	14,612	14,625	14,906	10,714
Total assets	$ 46,529	$ 44,951	$ 40,700	$ 40,648	$ 27,406
Current liabilities	$ 4,933	$ 4,459	$ 3,842	$ 3,969	$ 1,899
Long-term debt	8,869	7,582	7,111	7,422	3,647
Other deferred credits and other liabilities	19,757	18,859	17,005	16,592	13,152
Contingently redeemable noncontrolling interest [a]	28				
Noncontrolling interest	1,307	1,333	17	108	5
Member s equity	11,635	12,718	12,725	12,557	8,703
Total liabilities and member s equity	$ 46,529	$ 44,951	$ 40,700	$ 40,648	$ 27,406

(a) Represents mezzanine equity related to contingently redeemable equity contributions made by a noncontrolling interest holder of one of Generation s subsidiaries. See Note 18 Contingently Redeemable Noncontrolling Interest for further information.

Table of Contents

ComEd

The selected financial data presented below has been derived from the audited consolidated financial statements of ComEd. This data is qualified in its entirety by reference to and should be read in conjunction with ComEd s Consolidated Financial Statements and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	For the Years Ended December 31,				
(In millions)	**2015**	**2014**	**2013**	**2012**	**2011**
Statement of Operations data:					
Operating revenues	$ 4,905	$ 4,564	$ 4,464	$ 5,443	$ 6,056
Operating income	1,017	980	954	886	982
Net income	426	408	249	379	416

	December 31,				
(In millions)	**2015**	**2014**	**2013**	**2012**	**2011**
Balance Sheet data:					
Current assets	$ 1,518	$ 1,723	$ 1,540	$ 1,692	$ 2,127
Property, plant and equipment, net	17,502	15,793	14,666	13,826	13,121
Goodwill	2,625	2,625	2,625	2,625	2,625
Noncurrent regulatory assets	895	852	933	666	699
Other deferred debits and other assets	3,992	4,365	4,325	3,984	3,975
Total assets	$ 26,532	$ 25,358	$ 24,089	$ 22,793	$ 22,547
Current liabilities	$ 2,766	$ 1,923	$ 2,032	$ 1,655	$ 2,071
Long-term debt, including long-term debt to financing trusts	6,049	5,870	5,235	5,492	5,391
Noncurrent regulatory liabilities	3,459	3,655	3,512	3,229	3,042
Other deferred credits and other liabilities	6,015	6,003	5,782	5,094	5,006
Shareholders equity	8,243	7,907	7,528	7,323	7,037
Total liabilities and shareholders equity	$ 26,532	$ 25,358	$ 24,089	$ 22,793	$ 22,547

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)	**2015**	**2014**	**2013**	**2012**	**2011**
Statement of Operations data:					
Operating revenues	$ 3,032	$ 3,094	$ 3,100	$ 3,186	$ 3,720
Operating income	630	572	666	623	655
Net income	378	352	395	381	389
Net income attributable to common shareholder	378	352	388	377	385

Table of Contents

(In millions)	2015	2014	December 31, 2013	2012	2011
Balance Sheet data:					
Current assets	$ 842	$ 645	$ 821	$ 1,054	$ 1,218
Property, plant and equipment, net	7,141	6,801	6,384	6,078	5,874
Noncurrent regulatory assets	1,583	1,529	1,448	1,378	1,216
Other deferred debits and other assets	801	885	868	793	814
Total assets	$ 10,367	$ 9,860	$ 9,521	$ 9,303	$ 9,122
Current liabilities	$ 944	$ 653	$ 889	$ 1,158	$ 1,145
Long-term debt, including long-term debt to financing trusts	2,464	2,416	2,120	1,821	1,772
Noncurrent regulatory liabilities	527	657	629	538	585
Other deferred credits and other liabilities	3,196	3,013	2,818	2,717	2,595
Preferred securities				87	87
Shareholders equity	3,236	3,121	3,065	2,982	2,938
Total liabilities and shareholders equity	$ 10,367	$ 9,860	$ 9,521	$ 9,303	$ 9,122

BGE

The selected financial data presented below has been derived from the audited consolidated financial statements of BGE. This data is qualified in its entirety by reference to and should be read in conjunction with BGE s Consolidated Financial Statements and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	2015	For the Years Ended December 31, 2014	2013	2012	2011
Statement of Operations data:					
Operating revenues	$ 3,135	$ 3,165	$ 3,065	$ 2,735	$ 3,068
Operating income	558	439	449	132	314
Net income	288	211	210	4	136
Net income (loss) attributable to common shareholder	275	198	197	(9)	123

(In millions)	2015	2014	December 31, 2013	2012 (a)	2011 (a)
Balance Sheet data:					
Current assets	$ 845	$ 951	$ 1,009	$ 979	$ 969
Property, plant and equipment, net	6,597	6,204	5,864	5,498	5,132
Noncurrent regulatory assets	514	510	524	522	551
Other deferred debits and other assets	339	391	442	486	531
Total assets	$ 8,295	$ 8,056	$ 7,839	$ 7,485	$ 7,183
Current liabilities	$ 1,134	$ 794	$ 800	$ 980	$ 675
Long-term debt, including long-term debt to financing trusts and variable interest entities	1,732	2,109	2,179	1,949	2,166
Noncurrent regulatory liabilities	184	200	204	214	201
Other deferred credits and other liabilities	2,368	2,200	2,101	1,984	1,840
Preference stock not subject to mandatory redemption	190	190	190	190	190

Shareholders equity	2,687	2,563	2,365	2,168	2,111
Total liabilities and shareholders equity	$ 8,295	$ 8,056	$ 7,839	$ 7,485	$ 7,183

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

Table of Contents

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.

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 financial statements since 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 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 Power Regions in Generation), ComEd, PECO and BGE. See Note 25 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.

Financial Results. The following consolidated financial results reflect the results of Exelon for the year ended December 31, 2015 compared to the same period in 2014. The 2014 financial results only include the operations of CENG on a fully consolidated basis from the date Generation assumed

76

Table of Contents

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, 2015						2014	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon [(a)]	Variance
Operating revenues	$ 19,135	$ 4,905	$ 3,032	$ 3,135	$ (760)	$ 29,447	$ 27,429	$ 2,018
Purchased power and fuel expense	10,021	1,319	1,190	1,305	(751)	13,084	13,003	(81)
Revenue net of purchased power and fuel expense [(b)]	9,114	3,586	1,842	1,830	(9)	16,363	14,426	1,937
Other operating expenses								
Operating and maintenance	5,308	1,567	794	683	(30)	8,322	8,568	246
Depreciation and amortization	1,054	707	260	366	63	2,450	2,314	(136)
Taxes other than income	489	296	160	224	31	1,200	1,154	(46)
Total other operating expenses	6,851	2,570	1,214	1,273	64	11,972	12,036	64
Equity in losses of unconsolidated affiliates							(20)	20
Gain on sales of assets	12	1	2	1	2	18	437	(419)
Gain on consolidation and acquisition of businesses							289	(289)
Operating income (loss)	2,275	1,017	630	558	(71)	4,409	3,096	1,313
Other income and (deductions)								
Interest expense, net	(365)	(332)	(114)	(99)	(123)	(1,033)	(1,065)	32
Other, net	(60)	21	5	18	(30)	(46)	455	(501)
Total other income and (deductions)	(425)	(311)	(109)	(81)	(153)	(1,079)	(610)	(469)
Income (loss) before income taxes	1,850	706	521	477	(224)	3,330	2,486	844
Income taxes	502	280	143	189	(41)	1,073	666	(407)
Equity in (losses) earnings of unconsolidated affiliates	(8)				1	(7)		(7)
Net income (loss)	1,340	426	378	288	(182)	2,250	1,820	430
Net income (loss) attributable to noncontrolling interests and preference stock dividends	(32)			13		(19)	197	(216)
Net income (loss) attributable to common shareholders	$ 1,372	$ 426	$ 378	$ 275	$ (182)	$ 2,269	$ 1,623	$ 646

(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 $2,269 million for the year ended December 31, 2015 as compared to $1,623 million for the year ended December 31, 2014, and diluted earnings per average common share were $2.54 for the year ended December 31, 2015 as compared to $1.88 for the year ended December 31, 2014.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $1,937 million as compared to 2014. The year-over-year increase was primarily due to the following favorable factors:

Increase of $666 million at Generation primarily due to the inclusion of CENG s results on a fully consolidated basis in 2015, benefit of lower cost to serve load (including the absence of higher procurement costs for replacement power in 2014), the cancellation of the DOE spent

Table of Contents

nuclear fuel disposal fee, increased capacity prices, the inclusion of Integrys results in 2015, favorability from portfolio management optimization activities in the Mid-Atlantic and Midwest regions, and increased load served, partially offset by lower margins resulting from the 2014 sales of generating assets, lower realized energy prices, and the absence of the 2014 fuel optimization opportunities in the South region due to extreme cold weather;

Increase of $848 million at Generation due to mark-to-market gains of $257 million in 2015 from economic hedging activities as compared to losses of $591 million in 2014;

Increase of $132 million at Generation related to amortization of contracts recorded at fair value associated with prior acquisitions;

Increase of $228 million at ComEd primarily due to increased electric distribution and transmission formula rate revenues (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE);

Increase of $9 million at PECO primarily due to favorable weather and volume; and

Increase of $82 million at BGE primarily due to increased distribution revenue pursuant to increased rates effective December 2014 as a result of the electric and natural gas distribution rate case order issued by the Maryland PSC and increased transmission revenue.

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 $38 million at ComEd due to unfavorable weather and volume.

Operating and maintenance expense decreased by $246 million as compared to 2014 primarily due to the following favorable factors:

Long-lived asset impairments at Generation of $12 million in 2015 compared to $663 million in 2014.

Decrease of $44 million resulting from the absence of 2014 expenses recorded for a Constellation merger commitment at Generation;

Decreased storm costs at PECO and BGE of $78 million and $21 million, respectively;

Decreased uncollectible accounts expense at BGE of $49 million.

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

Increase in Generation s labor, contracting and materials costs of $323 million primarily due to the inclusion of CENG s results on a fully consolidated basis in 2015 and increased contracting spend related to energy efficiency projects;

Increase of $64 million as a result of an increase in the number of nuclear refueling outage days at Generation, including Salem, primarily related to the inclusion of CENG s plants on a fully consolidated basis in 2015;

Increase in labor, contracting and materials costs of $31 million related to preventative maintenance and other projects at ComEd;

Increased storm costs at ComEd of $27 million;

Increased costs associated with ComEd s uncollectible accounts expense of $27 million; and

An increase in pension and non-pension postretirement benefits expense of $47 million primarily at Exelon, Generation, and ComEd, resulting from the unfavorable impact of lower assumed pension and OPEB discount rates for 2015 and an increase in the life expectancy assumption for plan participants in 2015, partially offset by cost savings from plan design changes for certain OPEB plans effective April 2014 and forward.

Table of Contents

Depreciation and amortization expense increased by $136 million primarily as a result of the inclusion of CENG s results on a fully consolidated basis in 2015, increased nuclear decommissioning amortization at Generation, and increased depreciation expense across the operating companies for ongoing capital expenditures.

Taxes other than income increased $46 million primarily due to the inclusion of CENG s results on a fully consolidated basis in 2015 and increased sales and use tax at Corporate.

Gain on sales of assets decreased $419 million as a result of the absence of 2014 gains recorded on the sales of ownership interest in certain generating stations.

Gain on consolidation and acquisition of businesses decreased by $289 million due to a $261 million gain upon consolidation of CENG in 2014 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 in 2014 related to the Integrys acquisition.

Interest expense decreased by $32 million primarily as a result of mark-to market gains in 2015 as compared to mark-to-market losses in 2014 associated with an interest rate swap terminated in June 2015, partially offset by higher debt in 2015 related to financing activities associated with the pending PHI merger.

Other, net decreased by $501 million primarily at Generation as a result of the change in realized and unrealized gains and losses on NDT funds.

Exelon s effective income tax rates for the years ended December 31, 2015 and 2014 were 32.2% and 26.8%, respectively. See Note 15 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, 2015 and 2014, 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, 2015 were $2,227 million, or $2.49 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,068 million, or $2.39 per diluted share, for the same period in 2014. In addition to net income, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor s overall understanding of year-to-year operating results and provide an indication of Exelon s baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Table of Contents

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, 2015 as compared to 2014:

	For the years ended December 31, 2015		2014	
(All amounts after tax; in millions, except per share amounts)		**Earnings per Diluted Share**		**Earnings per Diluted Share**
Net Income Attributable to Common Shareholders	$ 2,269	$ 2.54	$ 1,623	$ 1.88
Mark-to-Market Impact of Economic Hedging Activities [(a)]	(158)	(0.18)	363	0.42
Unrealized Losses (Gains) Related to NDT Fund Investments [(b)]	115	0.13	(86)	(0.10)
Plant Retirements and Divestitures [(c)]			(245)	(0.28)
Asset Retirement Obligation [(d)]	(6)	(0.01)	(13)	(0.02)
Merger and Integration Costs [(e)]	58	0.07	124	0.14
Amortization of Commodity Contract Intangibles [(f)]	(5)		64	0.07
Reassessment of State Deferred Income Taxes [(g)]	41	0.05	(27)	(0.03)
Long-Lived Asset Impairments [(h)]	21	0.02	435	0.50
Bargain-Purchase Gain on Integrys Acquisition [(i)]			(28)	(0.03)
Gain on CENG Integration [(j)]			(159)	(0.18)
Tax Settlements [(k)]	(52)	(0.06)	(106)	(0.12)
Mark-to-Market Impact of PHI Merger Related Interest Rate Swaps [(l)]	(21)	(0.02)	61	0.07
PHI Merger Related Redeemable Debt Exchange [(m)]	13	0.01		
Reduction in State Income Tax Reserve [(n)]	(10)	(0.01)		
Midwest Generation Bankruptcy Recoveries [(o)]	(6)	(0.01)		
CENG Non-Controlling Interest [(p)]	(32)	(0.04)	62	0.07
Adjusted (non-GAAP) Operating Earnings	$ 2,227	$ 2.49	$ 2,068	$ 2.39

(a) Reflects the impact of (gains) losses for the years ended December 31, 2015 and 2014 (net of taxes of $99 million and $232 million, respectively) on Generation s economic hedging activities. See Note 13 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 losses (gains) for the years ended December 31, 2015 and 2014 (net of taxes of $148 million and $77 million, respectively) on Generation s NDT fund investments for Non-Regulatory Agreement Units. See Note 16 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 year ended December 31, 2014 (net of taxes of $163 million, respectively).

(d) Reflects a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the Non-Regulatory Agreement Units for the years ended December 31, 2015 and 2014 (net of taxes of $4 million).

(e) Reflects certain costs associated with mergers and acquisitions incurred for the years ended December 31, 2015 and 2014 (net of taxes of $38 million and $45 million, respectively) including professional fees, employee-related expenses, integration activities, upfront credit facilities fees, merger commitments, and certain pre-acquisition contingencies related to the Constellation merger, CENG integration and the Integrys and pending PHI acquisitions.

(f) Reflects the non-cash impact for the years ended December 31, 2015 and 2014 (net of taxes of $3 million and $68 million, respectively) of the amortization of commodity contracts recorded at fair value associated with prior acquisitions, if and when applicable.

(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 2015, reflects charges to earnings primarily related to the impairments of investments in long-term leases and Upstream assets (net of taxes of $13 million). In 2014, reflects charges to earnings related to the impairments of certain generating assets held for sale, investment in long-term leases, Upstream assets, and wind generating assets (net of taxes of $250 million).

(i) Reflects the excess of the fair value of assets and liabilities acquired over the purchase price of Integrys (net of taxes of $16 million).

Table of Contents

(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 2015 and 2014 of certain income tax positions on Constellation s pre-acquisition tax returns.
(l) Reflects the impact of mark-to-market activity on forward-starting interest rate swaps held at Exelon Corporate related to financing for the pending PHI acquisition for the years ended December 31, 2015 and 2014 (net of taxes of $14 million and $39 million, respectively).
(m) Reflects the costs associated with the exchange and redemption in December 2015 of certain mandatorily redeemable debt issued to finance the PHI merger (net of taxes of $8 million).
(n) Reflects the reduction of a previously recorded state income tax reserve associated with the 2014 sales of Keystone and Conemaugh for the year ended December 31, 2015.
(o) Reflects a benefit for the favorable settlement of a long-term railcar lease agreement pursuant to the Midwest Generation bankruptcy for the year ended December 31, 2015 (net of taxes of $4 million).
(p) Represents Generation s non-controlling interest related to CENG exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments and mark-to-market activity in 2015, and in 2014 the impact of unrealized gains and losses on NDT fund investments, costs incurred associated with the integration, non-cash amortization of intangible assets, net, related to commodity contracts, mark-to-market activity, and changes in asset retirement obligations.

Merger and Acquisition Costs

As presented in the table 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 years ended December 31, 2015 and 2014, expense has been recognized for costs incurred to achieve the Constellation merger, CENG integration, Integrys acquisition and pending PHI acquisition as follows:

	Pre-tax Expense Twelve Months Ended December 31, 2015				
Merger Integration and Acquisition Expense:	**Generation**	**ComEd**	**PECO**	**BGE**	**Exelon**
Financing [(a)]	$	$	$	$	$ 21
Transaction [(b)]					23
Other [(c)]	32	9	4	5	51
Total	$ 32	$ 9	$ 4	$ 5	$ 95

	Pre-tax Expense Twelve Months Ended December 31, 2014				
Merger Integration and Acquisition Expense:	**Generation**	**ComEd**	**PECO**	**BGE**	**Exelon**
Financing [(a)]	$	$	$	$	$ 31
Transaction [(b)]					26
Regulatory commitments [(d)]	44				44
Employee-related [(e)]	5				5
Other [(c)]	56	4	2	2	65
Total	$ 105	$ 4	$ 2	$ 2	$ 171

(a) Reflects costs incurred at Exelon related to the financing of the PHI acquisition, including upfront credit facility fees. Excludes mark-to-market activity on forward-starting swaps and costs associated with the exchange and redemption of mandatorily redeemable debt.
(b)

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.

(c) Costs to integrate CENG, Constellation and Integrys processes and systems into Exelon and to terminate certain Constellation debt agreements. Also includes professional fees primarily related to integration for the pending PHI acquisition.

Table of Contents

(d) Reflects costs incurred at Generation for a Constellation merger commitment for the year ended December 31, 2014.
(e) Costs primarily for employee severance, pension and OPEB expense and retention bonuses.

As of December 31, 2015, Exelon projects incurring total PHI acquisition and integration related costs of approximately $700 million, excluding the amounts Exelon and PHI are committed, if approved, to provide to the PHI utility s respective customers. Of this amount, including 2014 and through December 31, 2015, Exelon has incurred approximately $300 million of costs associated with the proposed merger. Included in this amount are costs to fund the merger of which $76 million has been expensed, $56 million has been paid and recorded as deferred debt issuance costs and $60 million has been incurred and charged to common stock. The remaining costs will be primarily within Operating and maintenance expense within Exelon s Consolidated Statements of Operations and Comprehensive Income and will also include approximately $60 million for integration costs expected to be capitalized to Property, plant and equipment. The increase from the previous estimate of $635 million is due to higher transaction costs primarily driven by the merger delay. This increase in transaction costs is partially offset by lower integration costs.

Pursuant to the conditions set forth by the MDPSC in its approval of the Constellation 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 for office space 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. Construction began late in the second quarter of 2014 and the building is expected to be ready for occupancy by the end of 2016. See Note 23 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 2016 and Beyond

Exelon s value proposition and competitive advantage come from its scope and its core strengths of operational excellence and financial discipline. Exelon leverages its integrated business model to create value. Exelon s regulated and competitive businesses feature a mix of attributes that, when combined, offer shareholders and customers a unique value proposition:

- Exelon s utilities provide a foundation for stable earnings, which translates to a stable currency in our stock.
- Generation s competitive businesses provide free cash flow to invest primarily into the utilities and in long-term, contracted assets.

Exelon believes its strategy provides a platform for optimal success in an energy industry experiencing fundamental and sweeping change.

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 improving 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. Additionally,

Table of Contents

ComEd, PECO and BGE anticipate making significant future investments 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.

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 to reduce earnings volatility. Generation leverages its energy generation portfolio to deliver energy to both wholesale and retail customers. 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 financial priorities are to maintain investment grade credit metrics at each of Exelon, Generation, ComEd, PECO and BGE, to maintain optimal capital structure and to return value to Exelon s shareholders with an attractive dividend throughout the energy commodity market cycle and through stable earnings growth. Exelon s Board of Directors approved a revised dividend policy. The approved policy would raise our dividend 2.5% each year for the next three years, beginning with the June 2016 dividend. The Board will take formal action to declare the next dividend in the second quarter.

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.

Continually optimizing the cost structure is a key component of Exelon s financial strategy. Through a recent focused cost management program the company has committed to reducing operation and maintenance expenses and capital costs by $350 million, of which approximately 35% of run-rate savings are expected to be achieved by the end of 2016 and fully realized in 2018. Savings will be allocated approximately 75%, 14%, 6% and 6% to Generation, ComEd, PECO and BGE, respectively. Exelon anticipates the earnings per share savings impact on EPS will be within $0.13 to $0.18 from 2018 forward.

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. Under the Merger Agreement, PHI s shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. Based on the outstanding shares of PHI s common stock as of December 31, 2015, PHI shareholders would receive $6.9 billion in total cash. In addition, in connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased $180 million of a class of nonvoting, nonconvertible and nontransferable preferred securities of PHI. The preferred securities are included in Other non-current assets on Exelon s Consolidated Balance Sheet. PHI has the right to redeem the preferred securities at its option for the purchase price paid plus accrued dividends, if any.

On November 2, 2015, Exelon and PHI each filed a new Notification and Report Form with the DOJ under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act) due to the expiration of the original filing. The HSR Act waiting period expired on December 2, 2015, and the HSR Act no longer precludes completion of the merger.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBPU), the Delaware Public Service Commission (DPSC), the Maryland Public Service Commission (MDPSC) 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. The March 6, 2015, order by the NJBPU approving the merger required that the consummation of the merger must take place no later than November 1, 2015 unless otherwise extended by the Board. On October 15, 2015, the NJBPU extended the November 1, 2015 date to June 30, 2016.

On February 13, 2015, Exelon and PHI announced that they had reached a settlement agreement in the proceeding before the DPSC to review the proposed merger. The settlement, which was amended on April 7, 2015, was signed and filed by Exelon, PHI, Delmarva Power & Light Company (DPL), the DPSC Staff, the Delaware Public Advocate, the Delaware Department of Natural Resources and Environmental Control, the Delaware Sustainable Energy Utility, the Mid-Atlantic Renewable Energy Coalition and the Clean Air Council. As part of this settlement, Exelon and PHI proposed a package of benefits to DPL customers and the state of Delaware including the establishment of customer rate credits of $40 million for DPL customers in Delaware, $2 million of funding for energy efficiency programs for DPL low income customers, and $2 million of funding for workforce development. On June 2, 2015, the DPSC issued an order accepting the settlement and approving the merger between Exelon and PHI.

On March 17, 2015, Exelon and PHI announced that they had reached settlements with multiple parties in the Maryland proceeding to review the proposed merger after filing a Request for Adoption of Settlements with the MDPSC. The settlements were signed and filed by Exelon, PHI, Montgomery County, Prince George s County, the National Consumer Law Center, National Housing Trust, the Maryland Affordable Housing Coalition, the Housing Association of Nonprofit Developers, and a consortium of recreational trail advocacy organizations led by the Mid-Atlantic Off-Road Enthusiasts. Exelon and PHI also announced a settlement with The Alliance for Solar Choice. On May 15, 2015, the MDPSC approved the merger after modifying a number of the conditions in the settlements, resulting in total rate credits of $66 million, funding for energy efficiency programs of $43.2 million, a Green Sustainability Fund of $14.4 million, 20 MWs of renewable generation development and increased penalties related to reliability commitments. On May 18, 2015, Exelon and PHI accepted and committed to fulfill the conditions.

On June 11, 2015, the Maryland Office of People s Counsel (OPC), the Sierra Club, and the Chesapeake Climate Action Network filed Petitions for Judicial Review of the MDPSC s approval of the merger with the Circuit Court for Queen Anne s County. On June 23, 2015, Public Citizen, Inc. filed its Petition for Judicial Review with the Circuit Court for Queen Anne s County. On July 10, 2015, Exelon and PHI filed a response in opposition to the Petitions for Review.

On July 21, 2015, the OPC filed a motion to stay the MDPSC order approving the merger and to set a schedule for discovery and presentation of new evidence. On July 29, 2015, Public Citizen, Inc. filed a response supporting OPC s motion to stay, and on July 31, 2015 the Sierra Club and the Chesapeake Climate Action Network filed a joint motion to stay. In July and August, Exelon, PHI, the MDPSC, Prince George s County and Montgomery County filed responses opposing the motions to stay. The judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the Circuit Court judge affirmed the MDPSC s order approving the merger and denied the petitions for judicial review filed by the OPC, the Sierra Club, the Chesapeake Climate Action Network (CCAN) and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special appeals, and on January 21, Sierra Club and CCAN filed a notice of appeal. In the ordinary course this appeal would be resolved no earlier than third quarter 2016.

On August 27, 2015, the District of Columbia Public Service Commission (DCPSC) issued an Opinion and Order denying approval of the merger, concluding that the merger as presented was not in the public interest. Exelon and PHI filed an Application for Reconsideration with the DCPSC on September 28, 2015. On October 6, 2015, Exelon, PHI, the District of Columbia Government, the Office of Peoples Counsel, the District of Columbia Water and Sewer Authority, the National Consumer Law Center, National Housing Trust and National Housing Trust Enterprise Preservation Corporation, and the Apartment and Office Building Association of Metropolitan Washington (collectively, Settling Parties) entered into a Nonunanimous Full Settlement Agreement and Stipulation (Settlement Agreement) with respect to the merger. Exelon and PHI subsequently filed a motion of joint applicants requesting the DCPSC to reopen the approval application to allow for consideration of the Settlement Agreement and granting additional requested relief. The new package of benefits totals $78 million and includes commitments to provide relief of residential customer base rate increases of $26 million, one-time direct bill credits of $14 million, low-income energy assistance of $16 million, improved reliability, a cleaner and greener D.C. through funding energy efficiency programs and development of renewable energy, and investment in local jobs and the local economy through workforce development of $5 million. It also guarantees charitable contributions totaling $19 million over 10 years.

On October 28, 2015, the DCPSC agreed to reopen the approval application to allow for consideration of the Settlement Agreement. Since then, parties supporting and opposing the Settlement filed testimony, participated in formal hearings and, on December 23, 2015, submitted final briefs to the DCPSC. The parties now await a formal decision from the DCPSC. The Merger Agreement provides that either Exelon or PHI may terminate the Merger Agreement if the merger is not completed by October 28, 2015. Pursuant to a Letter Agreement related to the Settlement Agreement, Exelon and PHI have agreed, among other things, that they will not exercise their rights to terminate the Merger Agreement before March 4, 2016, except under limited circumstances. If the DCPSC does not approve the Settlement Agreement by March 4, 2016, either Exelon or PHI may terminate the Settlement Agreement.

The settlements reached and commission orders received to date in Delaware, Maryland and New Jersey include a most favored nation provision which, generally speaking, requires allocation of merger benefits proportionately across all the jurisdictions. When applying the most favored nation provision to the settlement terms and other conditions established in the merger approvals received to date, and as proposed in the Settlement Agreement filed with the DCPSC, Exelon and PHI currently estimate direct benefits of $430 million or more on a net present value basis (excluding charitable contributions and renewable generation commitments) will be provided, including rate credits, funding for energy efficiency programs and other required commitments. Exelon and PHI anticipate substantially all of such amounts will be charged to earnings at the time of merger close and will be paid by the end of 2017. An additional $53 million will be charged to earnings for charitable contributions, which are required to be paid over a period of 10 years. Commitments to develop renewable generation, which are expected to be primarily capital in nature, will be recognized as incurred. Upon completion of the merger, the actual nature, amount, timing and financial reporting treatment for these commitments may be materially different from the current projection.

Exelon has been named in suits filed in the Delaware Chancery Court alleging that individual directors of PHI breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors breaches. The suits seek to enjoin PHI from completing the merger or seek rescission of the merger if completed. In addition, they also seek unspecified damages and costs. Exelon was also named in a federal court suit making similar claims. In September 2014, the parties reached a proposed settlement that would resolve all claims, which is subject to court approval. Final court approval of the proposed settlement is not anticipated until approximately 90 days after merger close. Exelon does not believe these suits will impact the completion of the transaction, and they are not expected to have a material impact on Exelon s results of operations.

Including 2014 and through December 31, 2015, Exelon has incurred approximately $259 million of expense associated with the proposed merger. Of the total costs incurred, $121 million is primarily related to acquisition and integration costs and $138 million are for costs incurred to finance the transaction. The financing costs include $22 million of costs associated with the private exchange offer and redemption of certain Senior Unsecured Notes (see Note 14 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further information on the exchange), as well as, a net loss of $64 million related to the settlement of forward-starting interest-rate swaps. These swaps were terminated in connection with the $4.2 billion issuance of debt; refer to Note 13 Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for more information. The financing costs exclude costs to issue equity and the initial debt offering which we recorded to Exelon s Consolidated Balance Sheets.

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 Merger Agreement is terminated due to a failure to obtain a required regulatory approval, Exelon may be required to pay PHI a termination fee equal to $180 million through the redemption by PHI of the outstanding nonvoting preferred securities described above for no consideration other than the nominal par value of the stock, plus reimbursement of PHI s documented out-of-pocket expenses up to a maximum of $40 million.

Merger Financing

Exelon has raised cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments, through the issuance of $4.2 billion of debt (of which $3.3 billion remains after execution of the exchange offer, see Note 14 Debt and Credit Agreements for further information on the exchange), $1.15 billion of junior subordinated notes in the form of 23 million equity units, the issuance of $1.9 billion of common stock, cash proceeds of $1.8 billion from asset sales primarily at Generation (after-tax proceeds of approximately $1.4 billion) and the remaining balance from cash on hand and/or short-term borrowings available to Exelon. Exelon will have sufficient cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments. See Note 14 Debt and Credit Agreements and Note 19 Shareholder s Equity of the Combined Notes to the Consolidated Financial Statements for further information on the debt and equity issuances.

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. Refer to Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the merger transaction.

Implications of Potential Early Plant Retirements

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation s nuclear plants. Factors that will continue to affect the economic value of Generation s nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative solutions in New York and Illinois such as the proposed Low Carbon Portfolio Standard (LCPS) legislation, the impact of final rules from the EPA requiring reduction of carbon and other emissions and the efforts of the states to implement those final rules, and the outcome of the Ginna RSSA hearing and settlement procedures and the resulting contractual terms and conditions.

Table of Contents

On September 10, 2015, after considering the results of the recent PJM capacity auctions, Exelon and Generation decided to defer decisions about the future operations of its Quad Cities and Byron nuclear plants and will offer both plants in the 2019/2020 auction in May 2016. As a result of clearing the other PJM capacity auction in September 2015 for the 2017/2018 transitional capacity auction, Exelon and Generation will continue to operate its Quad Cities nuclear power plant through at least May 2018. The Byron plant is already obligated to operate through May 2019. On October 29, 2015, Exelon and Generation announced the deferral of any decision about the future operations of its Clinton nuclear plant and plans to bid the plant into the MISO capacity auction for the 2016-2017 planning year April 2016. This decision was driven by MISO s acknowledgment of the need for market design changes to ensure long-term power system reliability in southern Illinois, the desire to provide Illinois policy makers with additional time to consider needed reforms as well as the potential long-term impact of EPA s Clean Power Plan. Exelon and Generation previously committed to cease operation of the Oyster Creek nuclear plant by the end of 2019. Exelon and Generation have not made any decisions regarding potential nuclear plant closures at other sites at this time.

As a result of a decision to early retire one or more other nuclear plants, certain changes in accounting treatment would be triggered and Exelon s and Generation s results of operations and cash flows could be materially affected by a number of items including, among other items: accelerated depreciation expense, impairment charges related to inventory that cannot be used at other nuclear units and cancellation of in-flight capital projects, accelerated amortization of plant specific nuclear fuel costs, employee-related costs (i.e. severance, relocation, retention, etc.), accelerated asset retirement obligation expense related to future decommissioning activities, and additional funding of nuclear decommissioning trust funds. In addition, any early plant retirement would also result in reduced operating costs, lower fuel expense, and lower capital expenditures in the periods beyond shutdown. While there are a number of Generation s nuclear plants that are at risk of early retirement, the following table provides the balance sheet amounts as of December 31, 2015 for significant assets and liabilities associated with the three nuclear plants currently considered by management to be at the greatest risk of early retirement due to their current economic valuations and other factors:

(in millions)	Quad Cities	Clinton	Ginna	Total
Asset Balances				
Materials and supplies inventory	$ 50	$ 57	$ 29	$ 136
Nuclear fuel inventory, net	218	107	60	385
Completed plant, net	1,030	579	127	1,736
Construction work in progress	11	9	11	31
Liability Balances				
Asset retirement obligation	(698)	(401)	(644)	(1,743)
NRC License Renewal Term	2032	2046[(a)]	2029	

(a) Assumes Clinton seeks and receives a 20-year operating license renewal extension.

In the event a decision is made to retire early one or more nuclear plants, the precise timing of the retirement date, and resulting financial statement impact, is uncertain and would be influenced by a number of factors such as the results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and decommissioning trust fund requirements, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity obligations and just prior to its next scheduled nuclear refueling outage date in that year.

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then Generation would be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional cash contributions to the NDTF to ensure sufficient funds are available.

As of December 31, 2015, all three of Generation s plants at the highest risk of early retirement (Quad Cities, Clinton, and Ginna) pass the NRC minimum funding test based on their current license lives. See Note 16 Asset Retirement Obligations for additional information on NRC minimum funding requirements. However, in the event of an early retirement just before their next individual refueling outages, it is estimated that Clinton and Ginna would no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDTF investments could appreciate in value. Quad Cities would also be at risk. However, the size of the guarantees are ultimately dependent on the decommissioning approach adopted at each site (i.e., DECON, Delayed DECON and SAFSTOR), the associated level of costs, and the decommissioning trust fund investment performance going forward. Considering the three alternative decommissioning approaches available to Generation for each site, parental guarantees of up to $315 million, $260 million, and $65 million for Clinton, Ginna, and Quad Cities, respectively, could be required in order for each site to access its NDTF for radiological decommissioning costs.

In addition, upon issuance of any required financial guarantees, while all three sites would be able to utilize their respective decommissioning trust funds for radiological decommissioning costs, the NRC must approve an additional exemption in order for Generation to utilize the NDTF funds to pay for non-radiological decommissioning costs (i.e. spent fuel management and site restoration costs). If a unit does not receive this exemption, the costs would be borne by Generation. Accordingly, based on current projections, it is expected that some portion of the spent fuel management and/or site restoration costs would need to be funded through supplemental cash from Generation. While the ultimate amounts may vary greatly and could be reduced by alternate decommissioning scenarios and/or reimbursement of certain costs under DOE reimbursement agreements or future litigation, across the three alternative decommissioning approaches available to Generation, for the next 10 years, Clinton and Ginna could incur spent fuel management and site restoration costs of up to $165 million and $115 million, net of taxes, respectively. The costs associated with Ginna would be shared by the plant co-owners at their respective ownership percentages. If Quad Cities fails the exemption test, at its ownership percentage Generation could be required to pay for spent fuel management costs of up to $180 million, net of taxes, but Quad Cities is better positioned to pass the test than the other two plants.

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. As a result, 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 sought to improve resource performance and reliability largely by limiting the excuses for non-performance and by increasing the penalties for performance failures. The proposal permits suppliers to include in capacity market offers additional costs and risk so they can meet these higher performance requirements. 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. Generation participated actively in PJM s stakeholder process through which PJM developed the proposal and also actively participated in the FERC proceeding including filing comments. On June 9, 2015, FERC approved PJM s filing largely as proposed by PJM, including transitional auction rules for delivery years 2016/2017 through 2017/2018. As a result of this and several related orders, PJM hosted its 2018/2019 Base Residual Auction (results posted on August 21, 2015) and its transitional auction for delivery year 2016/2017 (results posted on August 31, 2015) and its transitional auction for delivery years 2017/2018 (results posted on September 9, 2015).

MISO Capacity Market Results. On April 14, 2015, the Midcontinent Independent System Operator (MISO) released the results of its capacity auction covering the June 2015 through May 2016 delivery year. As a result of the auction, capacity prices for the zone 4 region in downstate Illinois increased to $150 per MW per day beginning in June 2015, an increase from the prior pricing of $16.75 per MW per day that was in effect from June 2014 to May 2015. Generation had an offer that was selected in the auction. However, due to Generation s ratable hedging strategy, the results of the capacity auction have not had a material impact on Exelon s and Generation s consolidated results of operations and cash flows.

Additionally, in late May and June 2015, separate complaints were filed at the FERC by each of the State of Illinois, the Southwest Electric Cooperative, Public Citizens, Inc., and the Illinois Industrial Energy Consumers challenging the results of this MISO capacity auction for the 2015/2016 delivery in MISO delivery zone 4. The complaints allege generally that 1) the results of the capacity auction for zone 4 are not just and reasonable, 2) the results should be suspended, set for hearing and replaced with a new just and reasonable rate, 3) a refund date should be established and that 4) certain alleged behavior by one of the market participants other than Exelon or Generation, be investigated.

On October 1, 2015, the FERC announced that it was conducting a non-public investigation (that does not involve Exelon or Generation) into whether market manipulation or other potential violations occurred related to the auction. On December 31, 2015, the FERC issued a decision that certain of the rules governing the establishment of capacity prices in downstate Illinois are not just and reasonable on a prospective basis. The FERC ordered that certain rules must be changed for the next auction scheduled for April 2016 that will set capacity prices beginning June 1, 2016. In response to this order, MISO must file certain rule changes with the FERC within 30 days and certain other changes within 90 days. The FERC continues to conduct its non-public investigation to determine if the April 2015 auction results were manipulated and, if so, whether refunds are appropriate. The FERC did establish May 28, 2015, the day the first complaint was filed, as the date from which refunds (if ordered) would be calculated, and it also made clear that the findings in the December 31, 2015 order do not prejudge the investigation or related proceedings. Generation cannot predict the impact the FERC order may ultimately have on future auction results, capacity pricing or decisions related to the potential early retirement of the Clinton nuclear plant, however, such impacts could be material to Generation s future results of operations and cash flows. See Note 9 Implications of Potential Early Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on the impacts of the MISO announcement.

MISO has acknowledged the need for capacity market design changes in the zone 4 region and stated that reforms to its capacity market process may be required to drive future investment and that it plans to engage stakeholders to consider such reforms. The FERC has also encouraged such efforts.

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.

Table of Contents

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 into 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 would be in commercial operation by June 1, 2015. CPV 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 challenged the constitutionality and other aspects of the New Jersey legislation in federal court. The actions taken by the MDPSC were also challenged in federal court in an action to which Exelon was not a party. The federal trial courts in both the New Jersey and Maryland actions effectively invalidated the actions taken by the New Jersey legislature and the MDPSC, respectively. Each of those decisions was upheld by the U.S. Court of Appeals for the Third Circuit and the U.S. Court of Appeals for the Fourth Circuit, respectively. However, the U.S. Supreme Court has agreed to review the matter, and there is 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. 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.

One such state is Ohio, where state-regulated utility companies FirstEnergy Ohio (FE) and AEP Ohio (AEP) have initiated actions at the Public Utilities Commission of Ohio (PUCO) to obtain approval for Riders that would effectively allow these two companies to pass through to all customers in their service territories the differences between their costs and market revenues on PPAs entered into between the utility and its merchant generation affiliate. Collectively more than 6,000MW of primarily coal-fired generation owned by FE and AEP s affiliates seek ratepayer guaranteed subsidies via the proposed Riders. Thus, the Riders are similar to the CfDs described above (except that the PPA Riders in Ohio would apply to certain existing generation facilities whereas the CfDs applied to new generation facilities). While AEP and FE initially filed for these Riders in 2013 and 2014, respectively, it was not until late 2015 that the proposals obtained meaningful traction when PUCO staff entered into a settlement and stipulation with the Ohio utilities supporting the proposals and recommending that the PUCO approve the Riders. Exelon is a participant in these proceedings. Although the matter is still in hearing and a decision by the PUCO is not expected until late February/early March 2016, it is increasingly likely that these subsidies may be approved by the PUCO. Litigation around these approvals is also likely.

Exelon opposes the proposals in Ohio, continues to monitor developments in Maryland and New Jersey, and participates in stakeholder and other processes to ensure that similar state subsidies are not developed. Exelon remains active in advocating for competitive markets, while opposing policies that require taxpayers and/ or consumers to subsidize or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity grid.

Energy Demand. Modest economic growth partially offset by energy efficiency initiatives is resulting in positive growth for electricity for BGE and PECO; and a decrease in projected load for electricity for ComEd. BGE, PECO and ComEd are projecting load volumes to increase (decrease) by 1.5%, 0.4% and (0.3)%, respectively, in 2016 compared 2015.

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 first, second, third and fourth quarter 2015 and first quarter 2016 dividends of $0.31 per share each on Exelon s common stock. The dividends for the first, second, third and fourth quarter 2015 were paid on March 10, 2015, June 10, 2015, September 10, 2015 and December 10, 2015. The first quarter 2016 dividend is payable on March 10, 2016.

All future quarterly dividends require approval by Exelon s board of directors. Exelon s Board of Directors approved a revised dividend policy. The approved policy would raise our dividend 2.5% each year for the next three years, beginning with the June 2016 dividend. The Board will take formal action to declare the next dividend in the second quarter.

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 2015 and 2016. 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, 2015, the percentage of expected generation hedged for the major reportable segments was 90%-93%, 60%-63% and 28%-31% for 2016, 2017, and 2018 respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. 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.

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, or a combination thereof, 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 2016 through 2020 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

Management continually evaluates growth opportunities aligned with Exelon s businesses, assets and markets, leveraging Exelon s expertise in those areas and offering sustainable returns.

Regulated Energy Businesses

The proposed merger with PHI provides an opportunity to accelerate Exelon s regulated growth to provide stable cash flows, earnings accretion, and dividend support. Additionally, ComEd, PECO and BGE anticipate investing approximately $18 billion over the next five years in electric and natural gas infrastructure improvements and modernization projects, including smart meter and smart grid initiatives, storm hardening, advanced reliability technologies, and transmission projects, which is projected to result in an increase to current rate base of approximately $8 billion by the end of 2020. ComEd, PECO and BGE invest in rate base where beneficial 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 and infrastructure development and enhancement programs.

Competitive Energy Businesses

Generation continually assesses the optimal structure and composition of our generation assets as well as explores wholesale and retail opportunities within the power and gas sectors. Generation s long-term growth strategy is to prioritize investments in long-term contracted generation across multiple technologies and identify and capitalize on opportunities that provide generation to load matching as a means to provide stable earnings, while identifying emerging technologies where strategic investments provide the option for significant future growth or influence in market development. As of December 31, 2015, Generation has currently approved plans to invest a total of approximately $2 billion in 2016 through 2018 on capital growth projects (primarily new plant construction and distributed generation).

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 $0.4 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, 2015, approximately 25%, or $2.1 billion, of the Registrants aggregate total commitments were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.9 billion was available as of December 31, 2015, due to outstanding letters of credit. There were no borrowings under the Registrants credit facilities as of December 31, 2015. See Note 14 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

Tax Matters

See Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Environmental Legislative and Regulatory Developments.

Exelon is actively involved in the EPA s development and implementation of environmental regulations for the electric industry, in pursuit of its business strategy to provide reliable, clean, affordable and innovative energy products. These efforts have most frequently involved air, water and waste controls for electric generating units, as set forth in the discussion below. These regulations have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and have resulted in the retirement of older, marginal facilities. Retirements of coal-fired power plants will continue as additional EPA regulations take effect, and as air quality standards are updated and further restrict emissions. Due to its low emission generation portfolio, Generation 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 EPA s rulemaking efforts, and it is uncertain whether any of these bills will become law.

Air Quality. In recent years, the EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act applicable to electric generating units. These regulations have resulted in more stringent emissions limits on fossil-fuel electric generating stations as states implement their compliance plans.

National Ambient Air Quality Standards (NAAQS). The EPA continues to review and update its NAAQS for conventional air pollutants relating to ground-level ozone and emissions of particulate matter, SO2 and NOx. Following five years of litigation, the EPA is finalizing the Cross State Air Pollution Rule that 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.

Mercury and Air Toxics Standard Rule (MATS). On December 16, 2011, the 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, and to make capital investments in pollution control equipment and incur higher operating expenses. The initial compliance deadline to meet the new standards was April 16, 2015; however, facilities may have been granted an additional one or two year extension in limited cases. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. In April 2014, the D.C. Circuit Court issued an opinion upholding MATS in its entirety. On appeal, the U.S. Supreme Court decided in June 2015 that the EPA unreasonably refused to consider costs in determining whether it is appropriate and necessary to regulate hazardous air pollutants emitted by electric utilities. The U.S. Supreme Court, however, did not vacate the rule; rather, it was remanded to the D.C. Circuit Court to take further action consistent with the U.S. Supreme Court s opinion on this single issue. As such, the MATS rule remains in effect. Exelon will continue to participate in the remanded proceedings before the D.C. Circuit Court as an intervenor in support of the rule.

Climate Change. 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. In the absence of Federal legislation, the EPA is moving forward with the regulation of GHG emissions under the Clean Air Act. In addition, there have been recent developments in the international regulation of GHG emissions pursuant to the United Nations Framework Convention on Climate Change (UNFCCC of Convention). See ITEM 1. BUSINESS, Global Climate Change for further discussion.

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. All of Generation s power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by changes to the existing regulations. Those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, Ginna, Gould Street, Handley, Mountain Creek, Mystic 7, Nine Mile Point Unit 1, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. See ITEM 1. BUSINESS , Water Quality for further discussion.

Solid and Hazardous Waste. In October 2015, the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants became effective. The rule classifies CCR as non-hazardous waste under RCRA. 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 does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted under the new federal regulations for coal ash disposal sites formerly owned by Generation. For these reasons, Generation is unable to predict whether and to what extent it may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations.

Table of Contents

See Note 23 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 (Exelon and Generation). 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 2016 through 2019 is expected to be between approximately $175 million and $200 million of capital (which includes approximately $25 million for the CENG plants) and $25 million of operating expense (which includes approximately $5 million for the CENG plants). Generation s current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See ITEM 1A. RISK FACTORS for additional information.

Financial Reform Legislation (Exelon, Generation, ComEd, PECO, and BGE). 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 rules, including the capital and margin rules for (non-cleared) Swaps that do not impact Generation s collateral requirements directly, but may have an indirect impact.

Table of Contents

These rules, in addition to certain international regulatory requirements still under development and that are similar to Dodd-Frank, could subject Generation s SD or MSP counterparties to additional and potentially significant capitalization requirements and could motivate the SDs and MSPs to increase collateral requirements or cash postings from their counterparties, including Generation.

Generation cannot predict to what extent, if any, further refinements to Dodd-Frank and international regulatory requirements relating to Swaps 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.

Market-Based Rates (Exelon, Generation, ComEd, PECO and BGE). Generation, ComEd, PECO and BGE are public utilities for purposes of the Federal Power Act and are required to obtain FERC s acceptance of rate schedules for wholesale electricity sales. Currently, Generation, ComEd, PECO and BGE have authority to execute wholesale electricity sales at market-based rates. As is customary with market-based rate schedules, FERC has reserved the right to suspend market-based rate authority on a retroactive basis if it subsequently determines that Generation, ComEd, PECO or BGE has violated the terms and conditions of its tariff or the Federal Power Act. FERC is also authorized to order refunds in certain instances if it finds that the market-based rates are not just and reasonable under the Federal Power Act.

As required by FERC s regulations, as promulgated in the Order No. 697 series, Generation, ComEd, PECO and BGE file market power analyses using the prescribed market share screens to demonstrate that Generation, ComEd, PECO and BGE qualify for market-based rates in the regions where they are selling energy, capacity, and ancillary services under market-based rate tariffs. On December 30, 2013, Generation, ComEd, PECO and BGE filed its updated analysis for the Northeast Region, based on 2012 historic test period data which the FERC accepted on August 5, 2014. On December 23, 2014, Generation filed its updated market power analysis for the Southeast Region which the FERC accepted on July 16, 2015. On December 23, 2014, Generation filed its updated market power analysis for the Central Region which the FERC accepted on November 25, 2015. On December 29, 2015, Generation filed its updated market power analysis for the SPP Region, and the FERC has not yet acted on the filing.

Illinois Low Carbon Portfolio Standard (Exelon, Generation and ComEd). In March 2015, the Low Carbon Portfolio Standard (LCPS) was introduced in the Illinois General Assembly. The legislation would require ComEd and Ameren to purchase low carbon energy credits to match 70 percent of the electricity used on the distribution system. The LCPS is a technology-neutral solution, so all generators of zero or low carbon energy would be able to compete in the procurement process, including wind, solar, hydro, clean coal and nuclear. Costs associated with purchasing the low carbon energy credits would be collected from customers. The LCPS proposal includes consumer protection such as a price cap that would limit the impact to a 2.015% increase based off 2009 monthly bills, or about $2 per month for the average residential electricity customer. The legislation also includes a separate customer rebate provision that would provide a direct bill credit to customers in the event wholesale prices exceed a specified level. The proposed legislation is pending and Exelon and Generation continue to work with stakeholders.

Legislation to Maximize Smart Grid Investments and to Promote a Cleaner and Greener Illinois (Exelon and ComEd). In March 2015, legislation was introduced in the Illinois General Assembly that would (1) build on ComEd s investment in the Smart Grid to reinforce the resiliency and security of the electrical grid to withstand unexpected challenges, (2) expand energy efficiency programs to reduce energy waste and increase customer savings, (3) further integrate clean renewable energy onto the power system, and (4) introduce a new demand-based rate design for residential customers that would allow for a more equitable sharing of smart grid costs among customers. The legislation also provides for additional funding for customer assistance programs for low-income customers. The proposed legislation is pending and ComEd continues to work with stakeholders.

Distribution Formula Rate Update Filing (Exelon and ComEd). On April 15, 2015, ComEd filed its annual distribution formula rate to request a total decrease to the revenue requirement of $50 million. On December 9, 2015, the ICC issued its final order which decreased the revenue requirement by $67 million, reflecting an increase of $85 million for the initial revenue requirement for 2015 and a decrease of $152 million related to the annual reconciliation for 2014. The rates took effect in January 2016. Intervenors requested a rehearing on specific issues. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information related to distribution formula updates.

2015 Pennsylvania Electric Distribution Rate Case (Exelon and PECO). On March 27, 2015, PECO filed a petition with the PAPUC requesting an increase of $190 million to its annual service revenues for electric delivery, which requested an ROE of 10.95%. On September 10, 2015, PECO and interested parties filed with the PAPUC a petition for joint settlement for an increase of $127 million in annual distribution service revenue. No overall ROE was specified in the settlement. On December 17, 2015, the PAPUC approved the settlement of PECO s electric distribution rate case. The approved electric delivery rates became effective on January 1, 2016.

The settlement includes approval of the In-Program Arrearage Forgiveness (IPAF) Program, which provides for forgiveness of a portion of the eligible arrearage balance of its low-income Customer Assistance Program (CAP) accounts receivable that will be determined as of program inception in October 2016. The forgiveness will be granted to the extent CAP customers remain current with payments. The Settlement guarantees PECO s recovery of two-thirds of the arrearage balance through a combination of customer payments and rate recovery, including through future rates cases if necessary. The remaining one-third of the arrearage balance will be absorbed by PECO, of which a portion has already been expensed as bad debt for CAP customer s accounts receivable balances.

Although the actual arrearage balance is not defined until program inception, PECO believes that it can reasonably estimate certain CAP customer accounts receivable balances as of December 31, 2015 that will remain outstanding at program inception. Management determined its best estimate based on historical collectability information. As a result, a regulatory asset of $7 million, representing the previously incurred bad debt expense associated with the estimated eligible accounts receivable balances, was recorded on Exelon s and PECO s Consolidated Balance Sheets as of December 31, 2015. This estimate will be revisited on a quarterly basis through program inception.

PECO Gas Main Extension Program (Exelon and PECO). 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. On October 1, 2015, the PAPUC approved the PECO Gas Main Extension Program, without modification. This approval allows local customers to pay significantly less initially to have natural gas installed at their homes and businesses.

2015 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On November 6, 2015, and as amended on January 5, 2016, BGE filed for electric and gas base rate increases with the MDPSC, ultimately requesting an increase of $121 million and $79 million, respectively, of which $103 million and $37 million, respectively, is related to recovery of smart grid initiative costs. BGE requested a ROE for the electric and gas distribution rate case of 10.6% and 10.5%, respectively. The new

Table of Contents

electric and gas base rates are expected to take effect in June 2016. BGE is also proposing to recover an annual increase of approximately $30 million for Baltimore City conduit lease fees through a surcharge. BGE cannot predict how much of the requested increase the MDPSC will approve or if it will approve BGE s request for a conduit fee surcharge.

Transmission Formula Rate Update Filing (Exelon, ComEd and BGE). On April 15, 2015 (and revised on May 19), ComEd filed its annual 2015 transmission formula rate update with the FERC, reflecting an increased revenue requirement of $86 million, including an increase of $68 million for the initial revenue requirement and an increase of $18 million related to the annual reconciliation. The filing establishes the revenue requirement used to set rates that took effect in June 2015, subject to review by the FERC and other parties. The time period for any challenges to ComEd s annual update expired in October 2015. No challenges were submitted. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information related to transmission formula update.

In April 2015, BGE filed its annual transmission formula rate update with the FERC, reflecting an increased revenue requirement of $10 million, including an increase of $13 million for the initial revenue requirement, inclusive of dedicated facilities charge revenues, and a decrease of $3 million related to the annual reconciliation for 2014. The filing establishes the revenue requirement used to set rates that took effect in June 2015. The time period for any challenges to BGE s annual update expired in October 2015. No challenges were submitted. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information related to the transmission formula update.

Grand Prairie Gateway Transmission Line (Exelon and ComEd). 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. The costs incurred for the project prior to May 21, 2014 were immaterial. ComEd has acquired numerous easements across the project route through voluntary transactions. ComEd will seek to acquire the property rights on the remaining 28 parcels through condemnation proceedings in the circuit courts. ComEd began construction of the line during the second quarter of 2015 with an in-service date expected in the second quarter of 2017.

FERC Ameren Order (Exelon and ComEd). 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. On July 20, 2015, FERC approved a settlement between Ameren and its customers to resolve the matter. ComEd believes that the FERC settlement authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/goodwill from its transmission formula rate, the impact could be material to ComEd s results of operations and cash flows.

FERC Order No. 1000 Compliance (ComEd, PECO and BGE). In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods applicable to certain new regional and interregional transmission projects. As part of the changes to the transmission planning procedures, the FERC required removal from all FERC-approved tariffs and agreements of a right of first refusal to build certain new transmission facilities. On October 25, 2012, 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 that, among other things, rejected the arguments of the PJM Transmission Owners that changes to the PJM governing documents were entitled to review under the *Mobile-Sierra* standard. The FERC s March 22, 2013 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 PECO 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. On May 15, 2014, FERC denied the PJM Transmission Owners rehearing request. Several parties filed an appeal of the FERC s May 15, 2014, Order which upheld PJM s right of first refusal language in the D.C. Circuit. The ultimate outcome of this proceeding cannot be predicted at this time, however, it could be material to Exelon, ComEd, PECO and BGE s results of operations and cash flows.

FERC Transmission Complaint (Exelon and BGE). On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the PHI 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 (and certain additional incentive basis points on certain projects). The parties sought a reduction in the base return on equity to 8.7% and changes to the formula rate process. Under FERC rules, any revenues subject to refund are limited to a fifteen month period and the earliest date from which the base ROE could be adjusted and refunds required is the date of 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.

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 reduction from 10.8% to 8.8%. The filing of the second complaint created 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. On February 20, 2015, the Chief Judge issued an order consolidating the two complaint proceedings and established an Initial Decision issuance deadline of February 29, 2016.

On November 6, 2015, BGE and the PHI companies and the complainants filed a settlement with FERC covering the issues raised in the complaints. The settlement provides for a 10% base ROE, effective March 8, 2016, which will be augmented by the PJM incentive adder of 50 basis points, and refunds to BGE customers of $13.7 million. The settlement also provides a moratorium on any change in the ROE until June 1, 2018. On December 16, 2015, the Presiding Administrative Law Judge submitted a Certification of the Uncontested Settlement to the FERC Commissioners. The settlement remains subject to FERC approval. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Table of Contents

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In 2013, legislation intended to accelerate gas infrastructure replacements in Maryland was signed into law. The law established a mechanism, separate from base rate proceedings, for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects incurred after June 1, 2013. The monthly surcharge and infrastructure replacement costs must be approved by the MDPSC and are subject to a cap and 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 November 16, 2015, BGE filed a surcharge update to be effective January 1, 2016, including a true-up of cost estimates included in the 2015 surcharge, along with its 2016 project list and projected capital estimates of $113 million to be included in the 2016 surcharge calculation. The MDPSC subsequently approved BGE s 2016 project list and the proposed surcharge for 2016, which included the 2015 surcharge true-up. As of December 31, 2015, BGE recorded a regulatory asset of less than $1 million, representing the difference between the surcharge revenues and program costs.

In 2014, the residential consumer advocate in Maryland appealed MDPSC s decision on BGE s infrastructure replacement plan and associated surcharge with the Baltimore City Circuit Court, who affirmed the MDPSC s decision. 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. During the third quarter of 2015, the residential consumer advocate, MDPSC, and BGE filed briefs. Oral argument in this matter was held before the Court of Special Appeals on November 3, 2015. On January 28, 2016, the Maryland Court of Special Appeals issued a decision affirming the MDPSC s decision. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

PJM Minimum Offer Price Rule (Exelon and Generation). PJM s capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. The FERC orders approving the MOPR were upheld by the United States Court of Appeals for the Third Circuit in February 2014.

Exelon continues to work with PJM stakeholders and through the FERC process to implement several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sanctioned subsidy contracts and capacity market speculators) cannot inappropriately affect capacity auction prices in PJM.

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.

Table of Contents

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

Generation s ARO associated with decommissioning its nuclear units was $8.2 billion at December 31, 2015. 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 decommissioning outcome scenarios.

As a result of recent nuclear plant retirements in the industry, nuclear operators and third-party service providers are obtaining more information about costs associated with decommissioning activities. At the same time, regulators are gaining more information about decommissioning activities which could result in changes to existing decommissioning requirements. In addition, as more nuclear plants are retired, it is possible that technological advances will be identified that could create efficiencies and lead to a reduction in decommissioning costs. These factors could result in material changes to Generation s current estimates as more information becomes available and could change the timing and probability assigned to the decommissioning 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 and/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, unless circumstances warrant more frequent updates (such as a change in assumed operating life for a nuclear plant). As part of the annual cost study update process, Generation evaluates newly assumed costs or substantive changes in previously assumed costs to determine if the cost estimate impacts are sufficiently material to warrant application of the updated estimates to the AROs across the nuclear fleet outside of the normal five-year rotating cost study update cycle.

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. All of the nuclear AROs are adjusted each year for the updated cost escalation factors.

Probabilistic Cash Flow Models. Generation s probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning cost levels, decommissioning approaches, and timing of plant shutdown 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 also assigned to three different decommissioning approaches as follows:

1. 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,

2.

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

Table of Contents

3. 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.

The actual decommissioning approach selected once a nuclear facility is shutdown will be determined by Generation at the time of shutdown and may be influenced by multiple factors including the funding status of the nuclear decommissioning trust fund at the time of shutdown.

The assumed plant shutdown timing scenarios have historically included the following two alternatives: (1) the probability of operating through the original 40-year nuclear license term, and (2) the probability of operating through an extended 60-year nuclear license term (regardless of whether such 20-year license extension had been received for each unit). During 2015, due to changing market conditions and regulatory environments, Generation began to consider and incorporate assumptions regarding plant shutdown timing scenarios for certain plants other than just the two scenarios historically considered. In addition to potential early shutdown scenarios, Generation also began in 2015 to incorporate into its ARO estimates some probability of a second, 20-year license renewal for some nuclear units. The successful operation of nuclear plants in the U.S. beyond the initial 40-year license terms has prompted the NRC to consider regulatory and technical requirements for potential plant operations for an 80-year nuclear operating term. As power market and regulatory environment developments occur, Generation evaluates and incorporates, as necessary, the impacts of such developments into its nuclear ARO assumptions and estimates.

Generation s probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal. Generation currently assumes DOE will begin accepting SNF in 2025. The SNF acceptance date assumption 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 long-term SNF storage. For more information regarding the estimated date that DOE will begin accepting SNF, see Note 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

License Renewals. Generation has received, has applied for, or plans to seek, 20-year license renewals for all of its nuclear units. Generation has successfully secured 20-year operating license renewal extensions (i.e., extending the total license term to 60 years) for twenty-one of its nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG and Braidwood Units 1 and 2 for which the NRC approved the renewed license on January 27, 2016). None of Generation s previous applications for an operating license extension has been denied. The 20-year license renewal for Oyster Creek nuclear unit was obtained in 2009, however, operations will cease by the end of 2019. For its remaining three operating units, Generation is in various stages of the process of pursuing similar extensions and has filed license renewal applications for two operating nuclear units and has until 2021 to seek license renewal for one remaining operating nuclear unit. Generation s assumptions regarding successful license extension for the remaining three operating units 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 twenty-one units to date.

Generation estimates that the failure to obtain initial license renewals to extend the operating life from 40 years to 60 years at any of its remaining nuclear units (assuming all other assumptions remain constant) would increase its ARO on average approximately $300 million per unit as of December 31, 2015. 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.

Table of Contents

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. Increases in the ARO as a result of upward revisions in estimated undiscounted cash flows are considered new obligations and are measured using a current CARFR as the increase creates a new cost layer within the ARO. Any decrease in the estimated undiscounted future cash flows relating to the ARO are treated as a modification of an existing ARO and, therefore, are measured using the average historical CARFR rates used in creating the initial ARO cost layers.

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 $8.2 billion to approximately $8.5 billion. The ultimate decommissioning obligation will be funded by the NDTs. The NDTs are recorded on Exelon s and Generation s Consolidated Balance Sheets at December 31, 2015 at fair value of approximately $10.3 billion and have an estimated targeted annual pre-tax return of 6.1% 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 2014 CARFRs rather than the 2015 CARFRs in performing its third quarter 2015 ARO update, Generation would have increased the ARO by approximately $940 million as compared to the actual increase to the ARO of $831 million; and ii) if the CARFR used in performing the third quarter 2015 ARO update (which also reflected increases in the amounts and changes to the timing of projected cash flows) was increased by 100 basis points or decreased by 50 basis points, the ARO would have increased by $100 million and $1.2 billion, respectively, as compared to the actual increase of $831 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.

Table of Contents

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, 2015	
Cost escalation studies		
Uniform increase in escalation rates of 50 basis points	$	1,600
Probabilistic cash flow models		
Increase the estimated costs to decommission the nuclear plants by 20 percent	$	1,420
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	$	410
Increase the likelihood of the SAFSTOR scenario by 20 percentage points and decrease the likelihood of the Delayed DECON scenario by 20 percentage points [a]	$	(240)
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	$	540
Extend the estimated date for DOE acceptance of SNF to 2030	$	(20)
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with an increase in discount rates of 100 basis points	$	(480)
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with a decrease in discount rates of 50 basis points	$	270

(a) The Delayed DECON scenario is currently assumed to be the most likely decommissioning approach for a majority of Exelon s nuclear plants.

For more information regarding accounting for nuclear decommissioning obligations, see Note 1 Significant Accounting Policies, Note 9 Implications of Potential Early Plant Retirements and Note 16 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements.

Goodwill (Exelon and ComEd)

As of December 31, 2015, 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.

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

104

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 11 Intangible Assets and Note 15 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, often utilizes 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 expected realization 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 11 Intangible Assets of the Combined Notes to Consolidated Financial Statements for further discussion.

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

Exelon, Generation, ComEd, PECO and BGE regularly monitor and evaluate their long-lived assets and asset groups, excluding goodwill, for impairment when circumstances indicate the carrying value of those assets may not be recoverable. Indicators of potential impairment may include a deteriorating business climate, including decline in energy prices, 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 utilizes 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 the cash flows of other assets and liabilities. For the generation business, the lowest level of independent cash flows is determined by the 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 assets or liabilities 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 related intangible assets and liabilities 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 for a long-lived asset or asset group, a comparison of the undiscounted expected future cash flows to the carrying value is performed. 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 less costs to sell. 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 assets or liabilities, as well as reduce the current period earnings by the amount of the impairment.

Generation evaluates natural gas and oil upstream properties on a quarterly basis to determine if they are impaired. Impairment indicators for natural gas and oil upstream properties are present 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.

Generation evaluates its equity method investments and other investments in debt and equity securities 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.

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.

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 if an event, regulatory 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 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 2015, which resulted in the implementation of new depreciation rates effective January 1, 2015.

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.

Table of Contents

PECO is required to file a depreciation rate study at least every five years with the PAPUC. In March 2015, 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, 2015 for electric transmission assets, July 1, 2015 for gas distribution assets and January 1, 2016 for electric distribution 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 Employee Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement employee benefit plans for substantially all Generation, ComEd, PECO, BGE and BSC employees. See Note 17 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension plans and other postretirement benefit plans.

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

Pension and other postretirement benefit plan assets include equity securities, including U.S. and international securities, and fixed income securities, as well as certain alternative investment classes such as real estate, private equity and hedge funds. See Note 17 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%, 7.00% and 7.50% for 2015, 2014 and 2013, respectively. The weighted average EROA assumption used in calculating other postretirement benefit costs was 6.46%, 6.59% and 6.45% in 2015, 2014 and 2013, 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 17 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 6.71% to estimate its 2016 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, 2015 were 0.29% and 0.80%, respectively, compared to an expected long-term return assumption of 7.00% and 6.46%, respectively.

Discount Rate. The discount rate used to determine the majority of pension and other postretirement benefit obligations was 4.29% at December 31, 2015. The discount rates at December 31, 2015 represent weighted-average rates for the majority of pension and other postretirement benefit plans. At December 31, 2015 and 2014, 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 3.68% to 4.43% to estimate its 2016 pension and other postretirement benefit costs.

Health Care Reform Legislation. In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers, including a provision that imposes an excise tax on certain high-cost plans whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Additional legislation was passed in December 2015 that made some changes to the law, including moving the implementation date of the excise tax from 2018 to 2020. Although the excise tax does not go into effect until 2020, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Certain key assumptions are required to estimate the impact of the excise tax on Exelon s other postretirement benefit obligation, including projected inflation rates (based on the CPI). 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 2015, 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 uses a mortality base table for its accounting valuation that is consistent with the IRS required table for funding (referred to as RP-2000). Exelon has a substantial employee population that provides a credible basis for mortality evaluation. Exelon is utilizing the Scale BB 2-Dimensional improvement scale with long-term improvements of 0.75% for its mortality improvement assumption.

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 2015 cost:				
Discount rate [(a)]	0.5%	$ (69)	$ (19)	$ (88)
	(0.5)%	83	30	113
EROA	0.5%	(73)	(11)	(84)
	(0.5)%	73	11	84
Health care cost trend rate [(b)]	1.00%	N/A	12	12
	(1.00)%	N/A	(9)	(9)
Change in benefit obligation at December 31, 2015:				
Discount rate [(a)]	0.5%	(1,042)	(249)	(1,291)
	(0.5)%	1,210	289	1,499
Health care cost trend rate [(b)]	1.00%	N/A	100	100
	(1.00)%	N/A	(89)	(89)

(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 11.9 years, 11.8 years and 11.8 years for the years ended December 31, 2015, 2014 and 2013, 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 10.8 years, 9.1 years and 8.7 years for the years ended December 31, 2015, 2014 and 2013, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 9.7 years, 10.1 years and 9.8 years for the years ended December 31, 2015, 2014 and 2013, 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, 2015, 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.

Table of Contents

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 13 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 remained probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and was reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurred. 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 models that take 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 12 Fair Value of Financial Assets and Liabilities and Note 13 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.

Table of Contents

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, 2015 and 2014 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 15 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 23 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.

Table of Contents

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

Sources of Revenue and Determination 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, revenues may fluctuate monthly as a result of customers electing to use an alternate supplier, 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

Table of Contents

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, investments made, allowed ROE 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, PECO and BGE 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. 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, 2015, 2014 and 2013 set forth below include intercompany transactions, which are eliminated in Exelon s consolidated financial statements.

Net Income Attributable to Common Shareholders by Registrant

	2015	2014	Favorable (unfavorable) 2015 vs. 2014 variance	2013	Favorable (unfavorable) 2014 vs. 2013 variance
Exelon	$ 2,269	$ 1,623	$ 646	$ 1,719	$ (96)
Generation	1,372	835	537	1,070	(235)
ComEd	426	408	18	249	159

PECO	378	352	26	388	(36)
BGE	275	198	77	197	1

Table of Contents

Results of Operations Generation

	2015	2014 [a]	Favorable (unfavorable) 2015 vs. 2014 variance	2013	Favorable (unfavorable) 2014 vs. 2013 variance
Operating revenues	$ 19,135	$ 17,393	$ 1,742	$ 15,630	$ 1,763
Purchased power and fuel expense	10,021	9,925	(96)	8,197	(1,728)
Revenue net of purchased power and fuel expense [b]	9,114	7,468	1,646	7,433	35
Other operating expenses					
Operating and maintenance	5,308	5,566	258	4,534	(1,032)
Depreciation and amortization	1,054	967	(87)	856	(111)
Taxes other than income	489	465	(24)	389	(76)
Total other operating expenses	6,851	6,998	147	5,779	(1,219)
Equity in (losses) earnings of unconsolidated affiliates		(20)	20	10	(30)
Gain on sales of assets	12	437	(425)	13	424
Gain on consolidation and acquisition of businesses		289	(289)		289
Operating income	2,275	1,176	1,099	1,677	(501)
Other income and (deductions)					
Interest expense	(365)	(356)	(9)	(357)	1
Other, net	(60)	406	(466)	355	51
Total other income and (deductions)	(425)	50	(475)	(2)	52
Income before income taxes	1,850	1,226	624	1,675	(449)
Income taxes	502	207	(295)	615	408
Equity in losses of unconsolidated affiliates	(8)		8		
Net income	1,340	1,019	321	1,060	(41)
Net income (loss) attributable to noncontrolling interest	(32)	184	(216)	(10)	194
Net income attributable to membership interest	$ 1,372	$ 835	$ 537	$ 1,070	$ (235)

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, beginning on April 1, 2014, the financial results include CENG s results of operations on a fully consolidated basis.
(b) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Membership Interest

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. Generation s net income attributable to membership interest increased compared to the same period in 2014 primarily due to higher revenue net of purchase power and fuel expense and lower operating and maintenance expense; partially offset by the absence of the 2014 gains recorded on the sales of Generation s ownership interest in generating stations, the absence of the 2014 gain recorded upon the consolidation of CENG, decreased other income and increased income tax expense. The increase in revenue, net of purchase power and fuel expense was primarily due to the inclusion of CENG s results on fully consolidated basis in 2015, the benefit of lower cost to serve load (including the absence of higher procurement costs for replacement power in 2014), the cancellation of the DOE spent nuclear fuel disposal fee, increased capacity prices, the inclusion of Integrys results in 2015, favorability from portfolio management optimization activities, increased load served, and mark-to-market gains in 2015 compared to mark-to-market losses in 2014, partially offset by lower margins resulting from the 2014 sale of generating assets, lower realized energy prices, and the absence of the 2014 fuel optimization opportunities in the South region due to extreme cold weather. The decrease in operating and maintenance expense was largely due to the reduction of long-lived asset impairment charges in 2015 versus 2014, partially offset by increased labor, contracting and materials expense due to the inclusion of CENG s results on a fully consolidated basis in 2015 and increased energy efficiency projects. The decrease in other income is primarily the result of the change in realized and unrealized gains and losses on NDT fund investments in 2015 as compared to 2014.

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 on a fully consolidated basis 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 and 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 gains on NDT fund investments.

Revenue Net of Purchased Power and Fuel Expense

The basis for Generation s reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation s hedging strategies and risk metrics are also aligned with these same geographic regions. Descriptions of each of Generation s six reportable segments are as follows:

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

Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, 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 ISO-NY, which covers the state of New York in its entirety.

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

Other Power Regions:

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: natural gas, as well as other miscellaneous business activities that are not significant to Generation s overall operating revenues or results of operations. Further, the following activities are not allocated to a region, and are reported in the table below in Other: unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities 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 owned generation and fuel costs associated with tolling agreements.

For the years ended December 31, 2015 compared to 2014 and December 31, 2014 compared to 2013, Generation s revenue net of purchased power and fuel expense by region were as follows:

			2015 vs. 2014			2014 vs. 2013	
	2015	2014	Variance	% Change	2013	Variance	% Change
Mid-Atlantic [(a)(b)(e)]	$ 3,571	$ 3,431	$ 140	4.1%	$ 3,270	$ 161	4.9%
Midwest [(c)]	2,892	2,599	293	11.3%	2,586	13	0.5%
New England	461	351	110	31.3%	185	166	89.7%
New York [(a)(e)]	634	483	151	31.3%	(4)	487	n.m.
ERCOT	293	317	(24)	(7.6)%	436	(119)	(27.3)%
Other Power Regions	250	327	(77)	(23.5)%	201	126	62.7%
Total electric revenue net of purchased power and fuel expense	8,101	7,508	593	7.9%	6,674	834	12.5%
Proprietary Trading	1	42	(41)	(97.6)%	(8)	50	n.m.

Mark-to-market gains (losses)	257	(591)	848	n.m.	504	(1,095)	n.m.
Other [d]	755	509	246	48.3%	263	246	93.5%
Total revenue net of purchased power and fuel expense	$ 9,114	$ 7,468	$ 1,646	22.0%	$ 7,433	$ 35	0.5%

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, beginning April 1, 2014, the financial results include CENG s results on a fully consolidated basis.
(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.
(c) Results of transactions with ComEd are included in the Midwest region.
(d) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes an $8 million increase to RNF, a $124 million decrease to RNF, and a $488 million decrease to RNF for the amortization of intangible assets related to energy contracts for the years ended December 31, 2015, 2014, and 2013, respectively.
(e) 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. See Note 26 Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Generation s supply sources by region are summarized below:

Supply Source (GWh)	2015	2014	2015 vs. 2014 Variance	2015 vs. 2014 % Change	2013	2014 vs. 2013 Variance	2014 vs. 2013 % Change
Nuclear Generation [a]							
Mid-Atlantic	63,283	58,809	4,474	7.6%	48,881	9,928	20.3%
Midwest	93,422	94,000	(578)	(0.6)%	93,245	755	0.8%
New York	18,769	13,645	5,124	37.6%		13,645	n.m.
Total Nuclear Generation	175,474	166,454	9,020	5.4%	142,126	24,328	17.1%
Fossil and Renewables [a]							
Mid-Atlantic	2,774	11,025	(8,251)	(74.8)%	11,714	(689)	(5.9)%
Midwest	1,547	1,372	175	12.8%	1,478	(106)	(7.2)%
New England	2,983	5,233	(2,250)	(43.0)%	10,896	(5,663)	(52.0)%
New York	3	4	(1)	(25.0)%		4	n.m.
ERCOT	5,763	7,164	(1,401)	(19.6)%	6,453	711	11.0%
Other Power Regions	7,848	7,955	(107)	(1.3)%	6,664	1,291	19.4%
Total Fossil and Renewables	20,918	32,753	(11,835)	(36.1)%	37,205	(4,452)	(12.0)%
Purchased Power							
Mid-Atlantic [b]	8,160	6,082	2,078	34.2%	14,092	(8,010)	(56.8)%
Midwest	2,325	2,004	321	16.0%	4,408	(2,404)	(54.5)%
New England	24,309	12,354	11,955	96.8%	7,655	4,699	61.4%
New York [b]		2,857	(2,857)	(100.0)%	13,642	(10,785)	(79.1)%
ERCOT	10,070	8,651	1,419	16.4%	13,459	(4,808)	(35.7)%
Other Power Regions	16,728	14,795	1,933	13.1%	14,931	(136)	(0.9)%
Total Purchased Power	61,592	46,743	14,849	31.8%	68,187	(21,444)	(31.4)%
Total Supply/Sales by Region [c]							
Mid-Atlantic [d]	74,217	75,916	(1,699)	(2.2)%	74,687	1,229	1.6%
Midwest [d]	97,294	97,376	(82)	(0.1)%	99,131	(1,755)	(1.8)%
New England	27,292	17,587	9,705	55.2%	18,551	(964)	(5.2)%
New York	18,772	16,506	2,266	13.7%	13,642	2,864	21.0%
ERCOT	15,833	15,815	18	0.1%	19,912	(4,097)	(20.6)%
Other Power Regions	24,576	22,750	1,826	8.0%	21,595	1,155	5.3%
Total Supply/Sales by Region	257,984	245,950	12,034	4.9%	247,518	(1,568)	(0.6)%

(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 the year ended December 31, 2015 includes physical volumes of 14,646 GWh in Mid-Atlantic and 18,769 GWh in New York for CENG and for the year ended December 31, 2014 includes physical volumes of 11,409 GWh in Mid-Atlantic and 13,645 GWh in New York for CENG. Prior to the integration date of April 1, 2014, CENG volumes were included in purchased power.

Table of Contents

(b) Purchased power includes physical volumes of 2,489 GWh and 12,067 GWh in the Mid-Atlantic and 2,857 GWh and 12,165 GWh in New York as a result of the PPA with CENG for the years ended December 31, 2014 and 2013, respectively. Since the integration date of April 1, 2014, CENG volumes are included in nuclear generation.
(c) Excludes physical proprietary trading volumes of 7,310 GWh, 10,571 GWh, and 8,762 GWh for the years ended December 31, 2015, 2014, and 2013, respectively.
(d) Includes affiliate sales to PECO and BGE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region.

Mid-Atlantic

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $140 million was primarily due to the inclusion of CENG s results on a fully consolidated basis for the full year in 2015, the benefit of lower cost to serve load (which includes the absence of higher procurement costs for replacement power due to extreme cold weather in the first quarter of 2014), increased load volumes served, higher nuclear volumes, the cancellation of the DOE spent nuclear fuel disposal fee, and favorability from portfolio management optimization activities, partially offset by lower capacity revenues, and lower generation volumes due to the sale of generating assets.

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 $161 million was primarily due to the consolidation of CENG, the cancellation of the DOE spent nuclear fuel disposal fees in 2014, 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.

Midwest

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The increase in revenue net of purchased power and fuel expense in the Midwest of $293 million was primarily due to higher capacity revenues, increased load volumes served, the inclusion of Integrys results in 2015, the cancellation of the DOE spent nuclear fuel disposal fee in 2014, and favorability from portfolio management optimization activities, partially offset by lower nuclear volumes.

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 $13 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.

New England

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The increase in revenue net of purchased power and fuel expense in New England of $110 million was primarily due to the benefit of lower cost to serve load, increased load volumes served, the inclusion of Integrys results in 2015, and favorability from portfolio management optimization activities, partially offset by lower generation volumes due to the sale of a generating asset.

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

New York

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $151 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the inclusion of CENG s results on a fully consolidated basis for the full year in 2015, increased nuclear volumes and the inclusion of Integrys results in 2015, partially offset by lower realized energy prices and decreased capacity revenues.

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.

ERCOT

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $24 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily due to lower realized energy prices and a decrease in generation volumes due to the sale of a generating asset, partially offset by the absence of higher procurement costs for replacement power in 2014 and decreased fuel costs.

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.

Other Power Regions

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The decrease in revenue net of purchased power and fuel expense in Other Power Regions of $77 million was primarily due to the amortization of contracts recorded at fair value associated with prior acquisitions, lower realized energy prices, the absence of the 2014 fuel optimization opportunities, partially offset by increased generation from power purchase agreements, and decreased fuel costs.

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 Power Regions was primarily due to higher generation volumes and higher realized energy prices.

Proprietary Trading

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $41 million decrease in revenue net of purchased power and fuel expense in Proprietary trading was primarily due to the absence of gains on congestion trading products.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The $50 million increase in revenue net of purchased power and fuel expense in Proprietary trading was primarily due to gains on congestion trading products.

Mark-to-market

Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. See Note 12 Fair Value of Financial

Table of Contents

Assets and Liabilities and Note 13 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, 2015 Compared to Year Ended December 31, 2014. Mark-to-market gains on economic hedging activities were $257 million in 2015 compared to losses of $591 million in 2014.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Mark-to-market losses on economic hedging activities were $591 million in 2014 compared to gains of $504 million in 2013.

Other

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $246 million increase in other revenue net of purchased power and fuel was primarily due to the amortization of energy contracts recorded at fair value associated with prior acquisitions, the inclusion of Integrys gas results in 2015, and an increase in distributed generation and energy efficiency activity. See Note 11 Intangible Assets of the Combined Notes to Consolidated Financial Statements for information regarding energy contract intangibles.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The $246 million increase in other revenue net of purchased power and fuel was primarily due to the amortization of energy contracts recorded at fair value associated with prior acquisitions, partially offset by a loss on gas inventory from lower of cost or market adjustments in 2014. See Note 11 Intangible Assets of the Combined Notes to Consolidated Financial Statements for information regarding energy contract intangibles.

Nuclear Fleet Capacity Factor

The following table presents nuclear fleet operating data for 2015, as compared to 2014 and 2013, 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. Generation considers capacity factor useful measure 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.

	2015	**2014**	**2013**
Nuclear fleet capacity factor (a)	93.7%	94.3%	94.1%

(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, 2015 Compared to Year Ended December 31, 2014. The nuclear fleet capacity factor, which excludes Salem, decreased in 2015 compared to 2014 primarily due to a higher number of refueling outage days and non-outage energy losses, partially offset by a lower number of unplanned outage days. For 2015 and 2014, planned refueling outage days totaled 290 and 275, respectively, and non-refueling outage days totaled 82 and 92, respectively

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

Table of Contents

were 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.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2015 compared to 2014, consisted of the following:

	Increase (Decrease) [(a)]
Impairment and related charges of certain generating assets [(b)]	$ (651)
Maryland merger commitments	(44)
Merger and integration costs	(28)
Midwest Generation bankruptcy charges	(14)
Decrease in asbestos bodily injury reserve	(12)
ARO update	8
Regulatory fees and assessments	10
Pension and non-pension postretirement benefits expense	15
Corporate allocations [(c)]	16
Accretion expense	18
Nuclear refueling outage costs, including the co-owned Salem plant [(d)]	64
Labor, other benefits, contracting and materials [(e)]	323
Other	37
Decrease in operating and maintenance expense	$ (258)

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the operating results include CENG s results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014 and for the entire year in 2015.
(b) Primarily relates to impairments of certain generating assets held-for-sale, Upstream assets, and wind generating assets during 2014 that did not reoccur in 2015.
(c) Reflects an increased share of corporate allocated costs primarily due to the inclusion of CENG beginning April 1, 2014.
(d) Reflects the unfavorable impacts of increased nuclear outages in 2015.
(e) Reflects an increase of labor, other benefits, contracting and materials costs primarily due to the inclusion of CENG on a fully consolidated basis in 2015. Also includes cost of sales of our other business activities that are not allocated to a region.

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 inclusion of CENG beginning April 1, 2014.
(e) Reflects the impact of increased nuclear outage days primarily due to the inclusion of CENG beginning April 1, 2014.

Depreciation and Amortization

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The increase in depreciation and amortization expense was primarily due to the inclusion of CENG s results on a fully consolidated basis in 2015, increased nuclear decommissioning amortization, and an increase in ongoing capital expenditures.

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.

Taxes Other Than Income

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The increase in taxes other than income was primarily due to the inclusion of CENG s results on a fully consolidated basis in 2015.

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

Equity in Earnings (Losses) of Unconsolidated Affiliates

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. 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.

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.

Gain (Loss) on Sales of Assets

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The decrease in gain (loss) on sales of assets in primarily related to the absence of $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, 2014 Compared to Year Ended December 31, 2013. The increase in gain (loss) on sales of assets is primarily related to $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.

Gain on Consolidation and Acquisition of Businesses

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The decrease in gain on consolidation and acquisition of businesses reflects the absence of 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 recorded in 2014, and the absence of a $28 million bargain-purchase gain related to the Integrys acquisition recorded in 2014.

Interest Expense

The changes in interest expense for 2015 compared to 2014 and 2014 compared to 2013 consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Interest expense on long-term debt	$ 53	$ 33
Interest expense on interest rate swaps	22	4
Interest expense on tax settlements	(37)	(21)
Other interest expense	(29)	(17)
Increase (decrease) in interest expense, net	$ 9	$ (1)

Other, Net

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The decrease in Other, net primarily reflects the net decrease in realized and unrealized gains related to the NDT fund investments of Generation s Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $(22) million and $67 million for the year ended December 31, 2015 and 2014, respectively, related to the contractual elimination of income tax expense associated with the NDT fund investments 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 fund investments.

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 tax returns and the increased net realized and unrealized gains related to the NDT fund investments of Generation s Non-Regulatory Agreement Units compared to net realized and unrealized gains in 2013, 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 (benefit) associated with the NDT fund investments 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 fund investments.

The following table provides unrealized and realized gains (losses) on the NDT fund investments of the Non-Regulatory Agreement Units recognized in Other, net for 2015, 2014 and 2013:

	2015	2014	2013
Net unrealized (losses) gains on decommissioning trust funds	$ (197)	$ 134	$ 146
Net realized gains on sale of decommissioning trust funds	$ 66	$ 77	$ 24

Table of Contents

Effective Income Tax Rate.

Generation s effective income tax rates for the years ended December 31, 2015, 2014 and 2013 were 27.1%, 16.9% and 36.7%, 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.

Results of Operations ComEd

	2015	2014	Favorable (Unfavorable) 2015 vs. 2014 Variance	2013	Favorable (Unfavorable) 2014 vs. 2013 Variance
Operating revenue	$ 4,905	$ 4,564	$ 341	$ 4,464	$ 100
Purchased power expense	1,319	1,177	(142)	1,174	(3)
Revenue net of purchased power expense (a)(b)	3,586	3,387	199	3,290	97
Other operating expenses					
Operating and maintenance	1,567	1,429	(138)	1,368	(61)
Depreciation and amortization	707	687	(20)	669	(18)
Taxes other than income	296	293	(3)	299	6
Total other operating expenses	2,570	2,409	(161)	2,336	(73)
Gain on sales of assets	1	2	(1)		2
Operating income	1,017	980	37	954	26
Other income and (deductions)					
Interest expense, net	(332)	(321)	(11)	(579)	258
Other, net	21	17	4	26	(9)
Total other income and (deductions)	(311)	(304)	(7)	(553)	249
Income before income taxes	706	676	30	401	275
Income taxes	280	268	(12)	152	(116)
Net income	$ 426	$ 408	$ 18	$ 249	$ 159

(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.

(b)

For regulatory recovery mechanisms, including ComEd s electric distribution and transmission formula rates, and riders, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).

Net Income

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. ComEd s Net income for the year ended December 31, 2015 was higher than the same period in 2014 primarily due to increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE), partially offset by unfavorable weather and volume.

Table of Contents

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 to the 2013 remeasurement of Exelon s like-kind exchange tax position and increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment), partially offset by unfavorable weather.

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.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the years ended December 31, 2015, 2014 and 2013, consisted of the following:

	For the Years Ended December 31,		
	2015	**2014**	**2013**
Electric	76%	80%	81%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2015, 2014 and 2013 consisted of the following:

	December 31, 2015		December 31, 2014		December 31, 2013	
	Number of customers	**% of total retail customers**	**Number of customers**	**% of total retail customers**	**Number of customers**	**% of total retail customers**
Electric	1,655,400	42%	2,426,900	63%	2,630,200	68%

Under an Illinois law allowing municipalities to arrange the purchase of electricity for their participating residents, the City of Chicago previously participated in ComEd s customer choice program and arranged the purchase of electricity from Constellation (formerly Integrys), for those participating residents. In September 2015, the City of Chicago discontinued its participation in the customer choice program and many of those participating residents resumed their purchase of electricity from ComEd. ComEd s Operating revenue has increased as a result of the City of Chicago switching, but that increase is fully offset in Purchased power expense.

Table of Contents

The changes in ComEd s Revenue net of purchased power expense for the year ended December 31, 2015 compared to the same period in 2014, and for the year ended December 31, 2014 compared to the same period in 2013, consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Weather	$ (16)	$ (16)
Volume	(22)	
Electric distribution revenue	180	(2)
Transmission revenue	48	30
Regulatory required programs	(1)	52
Uncollectible accounts recovery, net	27	41
Pricing and customer mix	(4)	5
Revenue subject to refund	9	(9)
Other	(22)	(4)
Increase in revenue net of purchased power	$ 199	$ 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 because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. For the years ended December 31, 2015 and 2014, unfavorable weather conditions reduced Operating revenue net of purchased power expense when compared to the prior years.

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, 2015, 2014 and 2013 consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2015**	**2014**	**Normal**	**2015 vs. 2014**	**2015 vs. Normal**
Heating Degree-Days	6,091	7,027	6,341	(13.3)%	(3.9)%
Cooling Degree-Days	806	799	842	0.9%	(4.3)%

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2014**	**2013**	**Normal**	**2014 vs. 2013**	**2014 vs. 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. 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, 2015, reflecting decreased average usage per residential customer and the impacts of energy efficiency programs, as compared to the same period in 2014. 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, electric distribution revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, allowed ROE, and other billing determinants. ComEd s allowed ROE 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, 2015, electric distribution revenue increased $180 million, primarily due to higher Operating and maintenance expense and increased capital investment, partially offset by lower allowed ROE due to decreased treasury rates. During the year ended December 31, 2014, electric distribution revenue decreased $2 million, primarily due to lower Operating and maintenance expense resulting from certain OPEB plan design changes, partially offset by increased capital investment. See Operating and Maintenance Expense below and Note 3 Regulatory Matters 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 years ended December 31, 2015 and 2014, ComEd recorded increased transmission revenue primarily due to higher Operating and maintenance expense and increased capital investment. See Operating and Maintenance Expense below and 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 purchased power administrative costs. The riders are designed to provide full and current cost recovery. An equal and offsetting amount has been included in Operating and maintenance expense. See 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 Operating and maintenance expense discussion below for additional information on this tariff.

Pricing and Customer Mix. For the year ended December 31, 2015, the decrease in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to lower overall effective rates due to increased usage across all major customer classes and change in customer mix. For the year ended December 31, 2014, 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.

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. Revenue net of purchase power expense was higher for the year ended December 31, 2015, due to the one-time revenue refund recorded in 2014 associated with the 2007 Rate Case.

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, recoveries of environmental costs associated with MGP sites, and recoveries of energy procurement costs.

Table of Contents

Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease)	Year Ended December 31,		Increase (Decrease)
	2015	2014	2015 vs. 2014	2014	2013	2014 vs. 2013
Operating and maintenance expense baseline	$ 1,353	$ 1,214	$ 139	$ 1,214	$ 1,205	$ 9
Operating and maintenance expense regulatory required programs [(a)]	214	215	(1)	215	163	52
Total operating and maintenance expense	$ 1,567	$ 1,429	$ 138	$ 1,429	$ 1,368	$ 61

(a) Operating and maintenance expense 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 year ended December 31, 2015, compared to the same period in 2014, and for the year ended December 31, 2014, compared to the same period in 2013, consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Baseline		
Labor, other benefits, contracting and materials [(a)]	$ 31	$ 56
Pension and non-pension postretirement benefits expense [(b)]	19	(85)
Storm-related costs	27	(11)
Uncollectible accounts expense provision [(c)]	(7)	12
Uncollectible accounts expense recovery, net [(c)]	34	29
Other [(d)]	35	8
	139	9
Regulatory required programs		
Energy efficiency and demand response programs	(1)	52
Increase in operating and maintenance expense	$ 138	$ 61

(a) Primarily reflects increased contracting costs related to preventative maintenance and other projects for the year ended December 31, 2015, and increased contracting costs resulting from new projects associated with EIMA for the year ended December 31, 2014. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding EIMA.

(b) The increase from 2014 to 2015 primarily reflects the unfavorable impact of lower assumed pension and OPEB discount rates and an increase in the life expectancy assumption for plan participants, partially offset by cost savings from plan design changes for certain OPEB plans effective April 2014 and forward. The decrease from 2013 to 2014 primarily reflects the cost savings from plan design changes for certain OPEB plans effective April 2014 and forward. See Note 16 Retirement Benefits of the Exelon 2014 Form 10-K 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 2015 and 2014, ComEd recorded a net increase in Operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery. An equal and offsetting amount has been recognized in Operating revenue for the periods presented.

(d) Primarily reflects increased information technology support services from BSC during 2015.

132

Table of Contents

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2015 compared to 2014, and 2014 compared to 2013, consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Depreciation expense [a]	$ 43	$ 46
Amortization regulatory assets [b]	(28)	(21)
Other	5	(7)
Increase in depreciation and amortization expense	$ 20	$ 18

(a) Depreciation expense increased due to ongoing capital expenditure during the years ended December 31, 2015 and 2014.
(b) For the years ended December 31, 2015 and 2014, primarily relates to a decrease in MGP regulatory asset amortization and ComEd s severance regulatory assets fully amortizing during 2014.

Taxes Other Than Income

Taxes other than income, which can vary year to year, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014, and for the year ended December 31, 2014, compared to the same period in 2013.

Interest Expense, Net

The changes in Interest expense, net, for the year ended 2015 compared to the same period in 2014, and for the year ended 2014 compared to the same period in 2013, consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Interest expense related to uncertain tax positions	$ 2	$ (275)[a]
Interest expense on debt (including financing trusts) [b]	13	16
Other	(4)	1
Increase (decrease) in interest expense, net	$ 11	$ (258)

(a) The reduction in interest expense in 2014 from 2013 is primarily attributable to the remeasurement of Exelon s like-kind exchange tax position recorded in the first quarter of 2013. See Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Primarily reflects an increase in interest expense due to the issuance of First Mortgage Bonds for the years ended December 31, 2015 and 2014. See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s debt obligations.

Effective Income Tax Rate

ComEd s effective income tax rates for the years ended December 31, 2015, 2014 and 2013, were 39.7%, 39.6% and 37.9%, respectively. See Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Table of Contents

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2015	2014	% Change 2015 vs 2014	Weather-Normal % Change	2013	% Change 2014 vs 2013	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	26,496	27,230	(2.7)%	(1.5)%	27,800	(2.1)%	0.3%
Small commercial & industrial	31,717	32,146	(1.3)%	(0.9)%	32,305	(0.5)%	(0.3)%
Large commercial & industrial	27,210	27,847	(2.3)%	(2.0)%	27,684	0.6%	0.7%
Public authorities & electric railroads	1,309	1,358	(3.6)%	(2.6)%	1,355	0.2%	(0.7)%
Total retail deliveries	86,732	88,581	(2.1)%	(1.4)%	89,144	(0.6)%	0.2%

Number of Electric Customers	As of December 31, 2015	2014	2013
Residential	3,550,239	3,502,386	3,480,398
Small commercial & industrial	370,932	369,053	367,569
Large commercial & industrial	1,976	1,998	1,984
Public authorities & electric railroads	4,820	4,815	4,853
Total	3,927,967	3,878,252	3,854,804

Electric Revenue	2015	2014	% Change 2015 vs 2014	2013	% Change 2014 vs 2013
Retail Sales [(a)]					
Residential	$ 2,360	$ 2,074	13.8%	$ 2,073	%
Small commercial & industrial	1,337	1,335	0.1%	1,250	6.8%
Large commercial & industrial	443	434	2.1%	427	1.6%
Public authorities & electric railroads	42	46	(8.7)%	48	(4.2)%
Total retail	4,182	3,889	7.5%	3,798	2.4%
Other revenue [(b)]	723	675	7.1%	666	1.4%
Total electric revenue	$ 4,905	$ 4,564	7.5%	$ 4,464	2.2%

(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 revenue also includes rental revenue, revenue related to late payment charges, revenue from other utilities for mutual assistance programs and recoveries of remediation costs associated with MGP sites.

Table of Contents

Results of Operations PECO

	2015	2014	Favorable (unfavorable) 2015 vs. 2014 variance	2013	Favorable (unfavorable) 2014 vs. 2013 variance
Operating revenue	$ 3,032	$ 3,094	$ (62)	$ 3,100	$ (6)
Purchased power and fuel	1,190	1,261	71	1,300	39
Revenue net of purchased power and fuel expense [(a)]	1,842	1,833	9	1,800	33
Other operating expenses					
Operating and maintenance	794	866	72	748	(118)
Depreciation and amortization	260	236	(24)	228	(8)
Taxes other than income	160	159	(1)	158	(1)
Total other operating expenses	1,214	1,261	47	1,134	(127)
Gain on sale of assets	2		2		
Operating income	630	572	58	666	(94)
Other income and (deductions)					
Interest expense, net	(114)	(113)	(1)	(115)	2
Other, net	5	7	(2)	6	1
Total other income and (deductions)	(109)	(106)	(3)	(109)	3
Income before income taxes	521	466	55	557	(91)
Income taxes	143	114	(29)	162	48
Net income	378	352	26	395	(43)
Preferred security dividends and redemption				7	7
Net income attributable to common shareholder	$ 378	$ 352	$ 26	$ 388	$ (36)

(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, 2015 Compared to Year Ended December 31, 2014. PECO s net income attributable to common shareholder for the year ended December 31, 2015 was higher than the same period in 2014, primarily due to a decrease in Operating and maintenance expense due to a decrease in storm costs.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. PECO s net income attributable to common shareholder for the year ended December 31, 2014 was lower than the same period in 2013, primarily due to an increase in Operating and maintenance expense due to an increase in storm costs partially offset by an increase in Operating revenue net of purchase power and fuel expense and a decrease in Income tax expense.

Table of Contents

Operating Revenue Net of Purchased Power and Fuel Expense

Electric and natural 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 as specified in the PAPUC-approved tariffs 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 PECO s GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and natural gas revenue net of purchased power and fuel expense.

Electric and natural 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 natural 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 natural gas revenue net of purchase power and fuel expense.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the years ended December 31, 2015, 2014, and 2013 consisted of the following:

	For the Years Ended December 31,		
	2015	2014	2013
Electric	70%	70%	68%
Natural Gas	25%	22%	19%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at December 31, 2015, 2014, and 2013 consisted of the following:

	December 31, 2015		December 31, 2014		December 31, 2013	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	563,400	35%	546,900	34%	531,500	34%
Natural Gas	81,100	16%	78,400	16%	66,400	13%

The changes in PECO s Operating revenue net of purchased power and fuel expense for the years ended December 31, 2015 and December 31, 2014 compared to the same periods in 2014 and 2013, respectively, consisted of the following:

	2015 vs. 2014 Increase (Decrease)			2014 vs. 2013 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$ 28	$ (19)	$ 9	$ (15)	$ 13	$ (2)
Volume	4	7	11	2	5	7
Pricing	4	2	6	(1)	(3)	(4)
Regulatory required programs	(6)		(6)	33		33

Other	(12)	1	(11)	(1)		(1)
Total increase (decrease)	$ 18	$ (9)	$ 9	$ 18	$ 15	$ 33

Weather. The demand for electricity and natural 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 natural 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 natural gas. Conversely, mild weather reduces demand. Operating revenue net of purchased power and fuel expense for the year ended December 31, 2015 was higher primarily due to the impact of favorable 2015 summer and first quarter winter weather conditions, partially offset by the impact of unfavorable fourth quarter 2015 winter weather conditions in PECO s service territory.

Operating revenue net of purchased power and fuel expense for the year ended December 31, 2014, 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.

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 years ended December 31, 2015 and December 31, 2014 compared to the same periods in 2014 and 2013, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2015**	**2014**	**Normal**	**2015 vs. 2014**	**2015 vs. Normal**
Heating Degree-Days	4,245	4,749	4,613	(10.6)%	(8.0)%
Cooling Degree-Days	1,720	1,311	1,301	31.2%	32.2%

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2014**	**2013**	**Normal**	**2014 vs. 2013**	**2014 vs. 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, for the year ended December 31, 2015, primarily reflects the impact of moderate economic and customer growth partially offset by energy efficiency initiatives on customer usages for gas and residential and small commercial and industrial electric classes. Additionally, the increase represents a shift in the volume profile across classes from large commercial and industrial classes to residential and small commercial and industrial classes for electric.

The increase in Operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2014, 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 increase in electric operating revenue net of purchased power expense as a result of pricing for the year ended December 31, 2015 is primarily attributable to increased monthly customer demand in the commercial and industrial classes. The increase in natural gas operating revenue net of fuel expense as a result of pricing for the year ended December 31, 2015, is primarily attributable to higher overall effective rates due to decreased retail gas usage.

The decrease in natural gas operating revenue net of fuel expense as a result of pricing for the year ended December 31, 2014, is primarily attributable to lower overall effective rates due to increased retail gas usage.

Table of Contents

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.

Other. The decrease in other electric revenue net of purchased power expense for the year ended December 31, 2015 reflects the impact of lower wholesale transmission revenue, which is impacted by the previous year s peak demand, which was lower in 2014 than in 2013.

Operating and Maintenance Expense

	Year Ended December 31, 2015	Year Ended December 31, 2014	Increase (Decrease) 2015 vs. 2014	Year Ended December 31, 2014	Year Ended December 31, 2013	Increase (Decrease) 2014 vs. 2013
Operating and maintenance expense baseline	$ 685	$ 761	$ (76)	$ 761	$ 668	$ 93
Operating and maintenance expense regulatory required programs[a]	109	105	$ 4	105	80	$ 25
Total operating and maintenance expense	$ 794	$ 866	$ (72)	$ 866	$ 748	$ 118

(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 2015 compared to 2014 and 2014 compared to 2013 consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Baseline		
Labor, other benefits, contracting and materials	$ 1	$ 12
Storm-related costs	(78)[a]	100[b]
Pension and non-pension postretirement benefits expense	3	(5)
Merger integration costs	2	(7)
Corporate allocation	9	5
Uncollectible accounts expense	(22)	(9)
Other	9	(3)
	(76)	93
Regulatory required programs		
Smart meter	(3)	7
Energy efficiency	8	17
Other	(1)	1
	4	25

Increase (decrease) in operating and maintenance expense	$ (72)	$ 118

138

(a) Reflects a reduction of $67 million in incremental storm costs, primarily as a result of the February 5, 2014 ice storm.
(b) Reflects an increase of $85 million in incremental storm costs, including the February 5, 2014 ice storm and the significant July 2014 storms.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2015 compared to 2014 and 2014 compared to 2013, consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Depreciation expense	$ 13	$ 8
Regulatory asset amortization	11	
Increase in depreciation and amortization expense	$ 24	$ 8

Taxes Other Than Income

Taxes other than income, which can vary year to year, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014, and the year ended December 31, 2014, compared to the same period in 2013.

Interest Expense, Net

Interest expense, net remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014, and the year ended December 31, 2014, compared to the same period in 2013.

Other, Net

Other, net remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014, and the year ended December 31, 2014, compared to the same period in 2013.

Effective Income Tax Rate

PECO s effective income tax rates for the years ended December 31, 2015, 2014 and 2013 were 27.4%, 24.5% and 29.1%, 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)	2015	2014	% Change 2015 vs. 2014	Weather-Normal % Change	2013	% Change 2014 vs. 2013	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	13,630	13,222	3.1%	0.3%	13,341	(0.9)%	0.5%
Small commercial & industrial	8,118	8,025	1.2%	0.6%	8,101	(0.9)%	%
Large commercial & industrial	15,365	15,310	0.4%	(0.5)%	15,379	(0.4)%	(0.1)%
Public authorities & electric railroads	881	937	(6.0)%	(6.0)%	930	0.8%	0.8%
Total electric retail deliveries	37,994	37,494	1.3%	(0.1)%	37,751	(0.7)%	0.1%

139

Table of Contents

Number of Electric Customers	As of December 31, 2015	2014	2013
Residential	1,444,338	1,434,011	1,423,068
Small commercial & industrial	149,200	149,149	149,117
Large commercial & industrial	3,091	3,103	3,105
Public authorities & electric railroads	9,805	9,734	9,668
Total	1,606,434	1,595,997	1,584,958

Electric Revenue	2015	2014	% Change 2015 vs. 2014	2013	% Change 2014 vs. 2013
Retail Sales [(a)]					
Residential	$ 1,599	$ 1,555	2.8%	$ 1,592	(2.3)%
Small commercial & industrial	428	423	1.2%	433	(2.3)%
Large commercial & industrial	221	217	1.8%	224	(3.1)%
Public authorities & electric railroads	31	32	(3.1)%	30	6.7%
Total retail	2,279	2,227	2.3%	2,279	(2.3)%
Other revenue [(b)]	207	221	(6.3)%	221	%
Total electric operating revenue	$ 2,486	$ 2,448	1.6%	$ 2,500	(2.1)%

(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 reflects 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)	2015	2014	% Change 2015 vs. 2014	Weather-Normal % Change	2013	% Change 2014 vs. 2013	Weather-Normal % Change
Retail Deliveries [(a)]							
Retail sales	59,003	62,734	(5.9)%	3.3%	57,613	8.9%	2.2%
Transportation and other	27,879	27,208	2.5%	1.2%	28,089	(3.1)%	(1.0)%
Total natural gas deliveries	86,882	89,942	(3.4)%	2.6%	85,702	4.9%	1.2%

Number of Gas Customers	As of December 31, 2015	2014	2013
Residential	467,263	462,663	458,356
Commercial & industrial	43,160	42,686	42,174

Total retail	510,423	505,349	500,530
Transportation	827	855	909
Total	511,250	506,204	501,439

Gas revenue	**2015**	**2014**	**% Change 2015 vs. 2014**	**2013**	**% Change 2014 vs. 2013**
Retail Sales [(a)]					
Retail sales	$ 511	$ 608	(16.0)%	$ 562	8.2%
Transportation and other	35	38	(7.9)%	38	%
Total natural gas operating revenue	$ 546	$ 646	(15.5)%	$ 600	7.7%

(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 reflects the cost of natural gas.

Results of Operations BGE

	2015	2014	Favorable (unfavorable) 2015 vs. 2014 variance	2013	Favorable (unfavorable) 2014 vs. 2013 variance
Operating revenue	$ 3,135	$ 3,165	$ (30)	$ 3,065	$ 100
Purchased power and fuel expense	1,305	1,417	112	1,421	4
Revenue net of purchased power and fuel expense [(a)]	1,830	1,748	82	1,644	104
Other operating expenses					
Operating and maintenance	683	717	34	634	(83)
Depreciation and amortization	366	371	5	348	(23)
Taxes other than income	224	221	(3)	213	(8)
Total other operating expenses	1,273	1,309	36	1,195	(114)
Gain on sales of assets	1		1		
Operating income	558	439	119	449	(10)
Other income and (deductions)					
Interest expense, net	(99)	(106)	7	(122)	16
Other, net	18	18		17	1
Total other income and (deductions)	(81)	(88)	7	(105)	17
Income before income taxes	477	351	126	344	7
Income taxes	189	140	(49)	134	(6)
Net income	288	211	77	210	1
Preference stock dividends	13	13		13	
Net income attributable to common shareholder	$ 275	$ 198	$ 77	$ 197	$ 1

(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 Attributable to Common Shareholder

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. Net income attributable to common shareholder was higher primarily due to an increase in Revenue net of purchased power and fuel expense as a result of the December 2014 electric and gas distribution rate order issued by the MDPSC, an increase in transmission formula rate revenues and a reduction in Operating and maintenance expense as a result of a decrease in bad debt expense and storm costs in the BGE service territory.

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

Table of Contents

Revenue net of purchased power and fuel expense as a result of the December 2013 and 2014 electric and gas distribution rate orders issued by the MDPSC offset by increases in Operating and maintenance expense and Depreciation expense.

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 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.

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 shareholder return component, which for residential SOS customers is being returned to residential distribution customers through December 31, 2016, 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.

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 and/or natural gas from a competitive natural gas supplier. This customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to SOS.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) at December 31, 2015, 2014 and 2013 consisted of the following:

	For the Years Ended December 31,		
	2015	**2014**	**2013**
Electric	61%	60%	61%
Natural Gas	56%	53%	54%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at December 31, 2015, 2014 and 2013 consisted of the following:

	December 31, 2015		**December 31, 2014**		**December 31, 2013**	
	Number of Customers	**% of total retail customers**	**Number of Customers**	**% of total retail customers**	**Number of Customers**	**% of total retail customers**

Electric	343,000	27%	364,000	29%	399,000	32%
Natural Gas	154,000	23%	161,000	25%	172,000	26%

Table of Contents

The changes in BGE s Operating revenue net of purchased power and fuel expense for the year ended December 31, 2015 compared to the same period in 2014 and for the year ended December 31, 2014 compared to the same period in 2013, respectively, consisted of the following:

	2015 Increase (Decrease)			2014 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution rate increase	$ 20	$ 35	$ 55	$ 57	$ 28	$ 85
Regulatory required programs	4	2	6	13	(1)	12
Transmission revenue	11		11	10		10
Other	10		10	(13)	10	(3)
Total increase	$ 45	$ 37	$ 82	$ 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, it will not be affected by actual weather or usage conditions. BGE bills or credits impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE s service territory. The changes in heating and cooling degree days in BGE s service territory for the year ended December 31, 2015 compared to the same period in 2014 and for the year ended December 31, 2014 compared to the same period in 2013, respectively, and normal weather consisted of the following:

	For the Year Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2015**	**2014**	**Normal**	**2015 vs. 2014**	**From Normal**
Heating Degree-Days	4,666	5,091	4,663	(8.3)%	0.1%
Cooling Degree-Days	924	732	875	26.2%	5.6%

	For the Year Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2014**	**2013**	**Normal**	**2014 vs. 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 Increase. The increase in distribution revenue for the year ended December 31, 2015 was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective in December 2014 in accordance with the MDPSC approved electric and natural gas distribution rate case order.

The increase in distribution revenue for the year ended December 31, 2014 was primarily due to the impact of new electric and natural gas distribution rates charged to customers that became

Table of Contents

effective in December 2013 and 2014, in accordance with the MDPSC approved electric and natural gas distribution rate case orders. 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 in BGE s Consolidated Statements of Operations and Comprehensive Income.

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. During the years ended December 31, 2015 and 2014, the increase in transmission revenue was primarily due to higher Operating and maintenance expense and increased capital investment. See Operating and Maintenance Expense below and Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other. 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 2015 compared to 2014 and 2014 compared to 2013 consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Baseline		
Labor, other benefits, contracting and materials	$ 12	$ 22
Pension and non-pension postretirement benefits expense	(1)	8
Storm-related costs [a]	(21)	21
Uncollectible accounts expense [b]	(49)	17
Merger integration costs	3	5
Other	22	10
(Decrease) increase in operating and maintenance expense	$ (34)	$ 83

(a) Storm-related costs decreased due to lack of major storms for the year ended December 31, 2015 compared to the same period in 2014.
(b) Uncollectible accounts expense decreased primarily due to improved customer behavior and favorable weather for the year ended December 31, 2015 compared to the same period in 2014.

Conduit Lease with City of Baltimore

On September 23, 2015, the Baltimore City Board of Estimates approved an increase in rental fees for access to the Baltimore City conduit system effective November 1, 2015, which is expected to result in an increase to operating and maintenance expense of approximately $24 million in 2016 subject to an annual increase based on the Consumer Price Index. On October 16, 2015, BGE filed a lawsuit against the City in the Circuit Court for Baltimore City to protect its customers from any improper use by the City of the conduit fee revenues and to place constraints on the City s ability to set the conduit fee in the future.

Table of Contents

Among the relief sought by BGE was a preliminary injunction preventing the City from enforcing its substantial increase in the conduit fee rate during the course of the litigation. A hearing was held in the Circuit Court for Baltimore County on December 15, 2015. While BGE s motion for preliminary injunction was denied, the Court s decision was premised upon several important concessions or acknowledgments made by the City in its written papers and at the hearing. Most importantly, the City conceded that it can charge BGE only for the actual costs of conduit maintenance and that a true-up process is required to the extent that the City fails to spend the amount collected for conduit maintenance.

As part of its electric and gas distribution rate case filed on November 6, 2015, and as amended on January 5, 2016, BGE is proposing to recover the annual increase in conduit fees, effective November 1, 2015 of approximately $30 million through a surcharge. BGE cannot predict if the MDPSC will approve BGE s request for a conduit fee surcharge.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2015 compared to 2014 and 2014 compared to 2013 consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Depreciation expense [(a)]	$ 2	$ 25
Regulatory asset amortization [(b)]	(6)	(1)
Other	(1)	(1)
(Decrease) increase in depreciation and amortization expense	$ (5)	$ 23

(a) Depreciation expense increased due to ongoing capital expenditures during the year ended December 31, 2015 compared to 2014 and 2014 compared 2013. The increase for the year ended December 31, 2015 compared to 2014 was offset by the effect of revised depreciation rates established in accordance with the MDPSC approved December 2014 electric and natural gas distribution rate case order.

(b) Regulatory asset amortization decreased for the year ended December 31, 2015 compared to the same period in 2014 due to a reduction in regulatory asset amortization related to demand response programs and revised recovery periods for certain regulatory assets in accordance with the MDPSC approved December 2014 electric and natural gas distribution rate case order.

Taxes Other Than Income

The change in taxes other than income for 2015 compared to 2014 and 2014 compared to 2013 consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Property tax	$ 3	$ 2
Franchise tax	1	4
Other	(1)	2

Increase in taxes other than income	$	3	$	8

145

Table of Contents

Interest Expense, Net

The decrease in Interest expense, net for 2015 compared to 2014 and 2014 compared to 2013 consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Interest expense on debt (including financing trusts)	$ (4)	$ (10)
Interest expense related to capitalization of interest / AFUDC	(2)	(6)
Interest expense related to uncertain tax positions	(1)	
Decrease in interest expense, net	$ (7)	$ (16)

Effective Income Tax Rate

BGE s effective income tax rates for the years ended December 31, 2015, 2014 and 2013 were 39.6%, 39.9% and 39.0%, respectively. See Note 15 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)	2015	2014	% Change 2015 vs. 2014	Weather-Normal % Change	2013	% Change 2014 vs. 2013	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	12,598	12,974	(2.9)%	n.m.	13,077	(0.8)%	n.m.
Small commercial & industrial	3,119	3,086	1.1%	n.m.	3,035	1.7%	n.m.
Large commercial & industrial	14,293	14,191	0.7%	n.m.	14,339	(1.0)%	n.m.
Public authorities & electric railroads	294	311	(5.5)%	n.m.	317	(1.9)%	n.m.
Total electric deliveries	30,304	30,562	(0.8)%	n.m.	30,768	(0.7)%	n.m.

Number of Electric Customers	As of December 31, 2015	2014	2013
Residential	1,137,934	1,125,369	1,120,431
Small commercial & industrial	113,138	112,972	112,850
Large commercial & industrial	11,906	11,730	11,652
Public authorities & electric railroads	285	290	292
Total	1,263,263	1,250,361	1,245,225

Table of Contents

Electric Revenue	2015	2014	% Change 2015 vs. 2014	2013	% Change 2014 vs. 2013
Retail Sales [(a)]					
Residential	$ 1,449	$ 1,404	3.2%	$ 1,404	%
Small commercial & industrial	273	271	0.7%	257	5.4%
Large commercial & industrial	469	491	(4.5)%	439	11.8%
Public authorities & electric railroads	32	32	%	31	3.2%
Total retail	2,223	2,198	1.1%	2,131	3.1%
Other revenue	267	262	1.9%	274	(4.4)%
Total electric operating revenue	$ 2,490	$ 2,460	1.2%	$ 2,405	2.3%

(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.

BGE Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2015	2014	% Change 2015 vs. 2014	Weather-Normal % Change	2013	% Change 2014 vs. 2013	Weather-Normal % Change
Retail Deliveries [(a)]							
Retail sales	96,618	99,194	(2.6)%	n.m.	94,020	5.5%	n.m.
Transportation and other [(b)(c)]	6,238	9,242	(32.5)%	n.m.	12,210	(24.3)%	n.m.
Total natural gas deliveries	102,856	108,436	(5.1)%	n.m.	106,230	2.1%	n.m.

Number of Gas Customers	As of December 31, 2015	2014	2013
Residential	616,994	609,626	611,532
Commercial & industrial	44,119	44,200	44,162
Total	661,113	653,826	655,694

Gas revenue	2015	2014	% Change 2015 vs. 2014	2013	% Change 2014 vs. 2013
Retail Sales [(a)]					
Retail sales	$ 607	$ 622	(2.4)%	$ 592	5.1%
Transportation and other [(b)(c)]	38	83	(54.2)%	68	22.1%
Total natural gas operating revenue	$ 645	$ 705	(8.5)%	$ 660	6.8%

(a) 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.
(b) Transportation and other gas revenue includes off-system revenue of 6,238 mmcfs ($35 million), 9,242 mmcfs ($72 million), and 12,210 mmcfs ($55 million) for the years ended 2015, 2014 and 2013, respectively.
(c) Other revenue includes operating revenue with affiliates.

Liquidity and Capital Resources

Exelon s and Generation s prior year activity presented below includes the activity of CENG, from the integration date effective April 1, 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. Exelon Corporate, Generation, ComEd, PECO and BGE s syndicated revolving credit facilities expire in 2018 and 2019. In addition, Generation has $0.4 billion in bilateral facilities with banks which have various expirations between March 2016 and January 2019. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the Credit Matters section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

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

See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants debt and credit agreements.

PHI Merger Financing

Exelon has raised cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments, through the issuance of $4.2 billion of debt (of which $3.3 billion remains after execution of the exchange offer, see Note 14 Debt and Credit Agreements for further information on the exchange), $1.15 billion of junior subordinated notes in the form of 23 million equity units, the issuance of $1.9 billion of common stock, cash proceeds of $1.8 billion from asset sales primarily at Generation (after-tax proceeds of approximately $1.4 billion) and the remaining balance from cash on hand and/or short-term borrowings available to Exelon. Exelon will have sufficient cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments. See Note 14 Debt and Credit Agreements and Note 19 Shareholder s Equity for further information on the debt and equity issuances. In the event the PHI merger is terminated, the Board of Directors could direct Exelon to use its existing cash on hand to retire debt, to return capital to shareholders or for other general corporate purposes.

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 23 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. On November 2, 2015 the funding relief was extended for an additional three years and premiums pension plans pay to the Pension Benefit Guaranty Corporation were further increased. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to make qualified pension plan contributions of $250 million to its qualified pension plans in 2016, of which Generation, ComEd, PECO and BGE expect to contribute $134 million, $30 million, $28 million and $31 million, respectively. Exelon s and Generation s expected qualified pension plan contributions above include $25 million related to the legacy CENG plans that will be funded by CENG as provided in an Employee Matters Agreement (EMA) between Exelon and CENG. Exelon s non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $21 million in 2016, of which Generation, ComEd, PECO and BGE will make payments of $9 million, $2 million, $1 million and $1 million respectively. See Note 17 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for the Registrants 2015 and 2014 pension contributions.

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. 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 $35 million in 2016, of which Generation, ComEd, PECO, and BGE

expect to contribute $13 million, $3 million, $1 million, and $18 million, respectively. See Note 17 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for the Registrants 2015 and 2014 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, Exelon would be required to either post a bond or pay the tax and interest for the tax years before the court to appeal the decision. If an adverse decision is reached in 2016, the potential tax and after-tax interest, exclusive of penalties, that could become payable may be as much as $860 million, of which approximately $300 million would be attributable to ComEd after consideration of Exelon s agreement to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd s equity, and the balance at Exelon. It is expected that Exelon s remaining tax years affected by the litigation will be settled following a final appellate decision which could take several years.

Exelon, Generation, and ComEd expect to receive tax refunds of approximately $430 million, $190 million, and $260 million, respectively, in 2016. PECO expects to make tax payments of approximately $7 million related to IRS positions settling in 2016.

State and local governments continue to face increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes or the imposition, extension or permanence of temporary tax levies.

On December 18, 2015, President Obama signed H.R. 2029, the Protecting Americans from Tax Hikes (PATH) Act. The Act included an extension of 50% bonus depreciation for 2015 2017. It also includes provisions for 40% and 30% bonus depreciation allowance for qualified property placed in service in 2018 and 2019, respectively. As a result of the 50% bonus depreciation extension for 2015, Exelon, Generation, ComEd, PECO, and BGE are estimated to generate incremental cash in 2016 of approximately $690 million, $350 million, $220 million, $70 million, and $50 million, respectively. Furthermore, the extension of 50% bonus depreciation resulted in a decrease to Generation s Domestic Production Activities Deduction, reducing cash tax benefits and increasing income tax expense by approximately $65 million in 2015. Due to the extension of bonus depreciation, ComEd s 2015 revenue requirement decreased by approximately $10 million (after-tax).

Table of Contents

The following table provides a summary of the major items affecting Exelon s cash flows from operations for the years ended December 31, 2015, 2014 and 2013:

	2015 (c)	2014	2015 vs. 2014 Variance	2013	2014 vs. 2013 Variance
Net income	$ 2,250	$ 1,820	$ 430	1,729	$ 91
Add (subtract):					
Non-cash operating activities (a)	5,630	5,884	(254)	4,159	1,725
Pension and non-pension postretirement benefit contributions	(502)	(617)	115	(422)	(195)
Income taxes	97	(143)	240	883	(1,026)
Changes in working capital and other noncurrent assets and liabilities (b)	(264)	(806)	542	(185)	(621)
Option premiums received (paid), net	58	38	20	(36)	74
Collateral received (posted), net	347	(1,719)	2,066	215	(1,934)
Net cash flows provided by operations	$ 7,616	$ 4,457	$ 3,159	$ 6,343	$ (1,886)

(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 24 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) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2015 and 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.

Cash flows provided by operations for the year ended December 31, 2015, 2014 and 2013 by Registrant were as follows:

	2015	2014	2013
Exelon (a)	$ 7,616	$ 4,457	$ 6,343
Generation (a)	4,199	1,826	3,887
ComEd	1,896	1,326	1,218
PECO	770	712	747
BGE	782	740	561

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2015 and 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.

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 2015, 2014 and 2013 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 an exchange or in the OTC markets. During 2015, 2014 and 2013, Generation had net collections/(payments) of counterparty cash collateral of $407 million, $(1,748) million and $162 million, respectively, primarily due to market conditions that resulted in changes to

Generation s net mark-to-market position, as well as Exelon s decision to post more cash collateral in 2014 compared to using letters of credit in 2015 to support the PHI merger financing.

During 2015, 2014 and 2013, Generation had net collections/(payments) of approximately $58 million, $38 million and $(36) million, respectively, related to purchases and sales of options. The level of option activity in a given year may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

During 2015, 2014 and 2013, ComEd s payables for Generation energy purchases increased/(decreased) by $(28) million, $5 million and $(16) million, respectively, and payables to other energy suppliers for energy purchases increased by $2 million, $27 million and $35 million, respectively.

During 2015, ComEd posted $31 million of cash collateral to PJM. During 2014, ComEd posted no cash collateral to PJM. ComEd s collateral posted with PJM has increased year over year primarily due to higher RPM credit requirements and higher PJM billings resulting from increased load being served by ComEd as a result of City of Chicago customers switching back to ComEd.

PECO

During 2015, 2014 and 2013, PECO s payables to Generation for energy purchases increased/(decreased) by $7 million, $(9) million and $(17) million, respectively, and payables to other energy suppliers for energy purchases increased/(decreased) by $(38) million, $10 million and $39 million, respectively.

BGE

During 2015, 2014 and 2013, BGE s payables to Generation for energy purchases increased/(decreased) by $(9) million, $13 million and $(4) million, respectively, and payables to other energy suppliers for energy purchases decreased by $(25) million, $(7) million and $(12) million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for the year ended December 31, 2015, 2014, and 2013 by Registrant were as follows:

	2015	2014	2013
Exelon [(a)]	$ (7,822)	$ (4,599)	$ (5,394)
Generation [(a)]	(4,069)	(1,767)	(2,916)
ComEd	(2,362)	(1,655)	(1,387)
PECO	(588)	(649)	(531)
BGE	(675)	(622)	(571)

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2015 and 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.

Table of Contents

Generation

Generation has entered into several agreements to acquire equity interests in privately held development stage entities which develop energy-related technology. The agreements contain a series of scheduled investment commitments, including in-kind services contributions. There are approximately $327 million of anticipated expenditures remaining through 2018 to fund anticipated planned capital and operating needs of the associated companies, of which up to $172 million will be contributed by a non-controlling interest holder. See Note 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further details of Generation s equity interests.

Capital expenditures by Registrant for the year ended December 31, 2015, 2014, and 2013 and projected amounts for 2016 are as follows:

	Projected 2016 [(a)]	**2015**	**2014**	**2013**
Exelon [(b)]	$ 7,600	$ 7,624	$ 6,077	$ 5,395
Generation [(b)(e)]	3,600	3,841	3,012	2,752
ComEd [(c)]	2,425	2,398	1,689	1,433
PECO	675	601	661	537
BGE	825	719	620	587
Other [(d)]	75	65	95	86

(a) Total projected capital expenditures do not include adjustments for non-cash activity.
(b) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2015 and 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(c) The capital expenditures and 2016 projections include $610 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) Generation s capital expenditures for the projected full year 2016 includes nuclear fuel of $1.1 billion and growth expenditures of $1.4 billion.

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 through 2016 associated with the CIP V.5 compliance implementation project, which are included in projected capital expenditures above.

Generation

Approximately 32% and 15% of the projected 2016 capital expenditures at Generation are for the acquisition of nuclear fuel and the construction of new natural gas plants, respectively, with the remaining amounts reflecting investment in renewable energy and 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.

Table of Contents

ComEd, PECO and BGE

Approximately 86%, 98% and 97% of the projected 2016 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. In addition to the capital expenditure for continuing projects, ComEd s total expenditures include smart grid/smart meter technology required under EIMA and for PECO and BGE, total capital expenditures related to their respective smart meter program.

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 have been 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 2016 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 a combination of internally generated funds and borrowings and additional capital contributions from parent, including ComEd s capital expenditures associated with EIMA as further discussed in Note 3 Regulatory Matters 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, 2015, 2014, and 2013 by Registrant were as follows:

	2015	**2014**	**2013**
Exelon [a]	$ 4,830	$ 411	$ (826)
Generation [a]	(479)	(537)	(384)
ComEd	467	359	61
PECO	83	(250)	(361)
BGE	(162)	(85)	(48)

(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.

Table of Contents

***Debt*.**

See Note 14 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 2015, 2014 and 2013 by Registrant was as follows:

During the year ended December 31, 2015, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Senior Unsecured Notes [(a)]	1.55%	June 9, 2017	$ 550	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes [(a)]	2.85%	June 15, 2020	900	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes [(a)(b)]	3.95%	June 15, 2025	1,250	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes [(a)(b)]	4.95%	June 15, 2035	500	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes [(a)(b)]	5.10%	June 15, 2045	1,000	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Long Term Software License Agreement	3.95%	May 1, 2024	111	Procurement of software licenses
Generation	Senior Unsecured Notes [(c)]	2.95%	January 15, 2020	750	Fund the optional redemption of Exelon s $550 million, 4.550% Senior Notes and for general corporate purposes

155

Table of Contents

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	AVSR DOE Nonrecourse Debt [d]	2.29 - 2.96%	January 5, 2037	39	Antelope Valley solar development
Generation	Energy Efficiency Project Financing [e]	3.71%	July 31, 2017	42	Funding to install energy conservation measures in Coleman, Florida
Generation	Energy Efficiency Project Financing [e]	3.55%	November 15, 2016	19	Funding to install energy conservation measures in Frederick, Maryland
Generation	Tax Exempt Pollution Control Revenue Bonds [f]	2.50 - 2.70%	2019 - 2020	435	General corporate purposes
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	100	Albany Green Energy biomass generation development
Generation	Nuclear Fuel Procurement Contract	3.15%	September 30, 2020	57	Procurement of nuclear fuel
ComEd	First Mortgage Bonds, Series 118	3.70%	March 1, 2045	400	Refinance maturing mortgage bonds, repay a portion of ComEd s outstanding commercial paper obligations and for general corporate purposes
ComEd	First Mortgage Bonds, Series 119	4.35%	November 15, 2045	450	Repay a portion of ComEd s outstanding commercial paper obligations and for general corporate purposes.
PECO	First and Refunding Mortgage Bonds	3.15%	October 15, 2025	350	General corporate purposes

(a) See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of the merger financing.
(b) In connection with the issuance of PHI merger financing, Exelon terminated its floating-to-fixed interest rate swaps that had been designated as cash flow hedges. See Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for further information.
(c) In connection with the issuance of Senior Unsecured Notes, Exelon terminated floating-to-fixed interest rate swaps that had been designated as cash flow hedges. See Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for further information on the swap termination.
(d) See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.
(e) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.
(f) The Tax Exempt pollution Control Revenue Bonds have a mandatory put date that ranges from March 1, 2019 September 1, 2020.

Table of Contents

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

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Junior Subordinated Notes	2.50%	June 1, 2024	$ 1,150	Finance a portion of the pending merger with PHI and for general corporate purposes
Generation	Nuclear Fuel Purchase Contract	3.25 - 3.35%	June 30, 2018	70	Procurement of uranium
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	300	General corporate purposes
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 18, 2021	675	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	3.06 - 3.14%	January 5, 2037	126	Antelope Valley solar development
ComEd	First Mortgage Bonds, Series 115	2.15%	January 15, 2019	300	Refinance maturing mortgage bonds and general corporate purposes
ComEd	First Mortgage Bonds, Series 116	4.70%	January 15, 2044	350	Refinance maturing mortgage bonds and general corporate purposes
ComEd	First Mortgage Bonds, Series 117	3.10%	November 1, 2024	250	Repay commercial paper obligations and general corporate purposes
PECO	First and Refunding Mortgage Bonds	4.15%	October 1, 2044	300	Refinance existing mortgage bonds and general corporate purposes

Table of Contents

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	2.21 - 2.44%	July 22, 2016	$ 5	Fund Upstream gas activities
Generation	AVSR DOE Nonrecourse Debt	2.53 - 3.35%	January 5, 2037	227	Antelope Valley solar development
Generation	Social Security Administration Project Financing	2.93%	February 18, 2015	1	Funding to install conservation measures for the Social Security Administration Headquarters facility in Maryland
Generation	Energy Efficiency Project Financing	4.40%	August 31, 2014	9	Funding to install energy conservation measures in Beckley, West Virginia
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	613	General corporate purposes
ComEd	First Mortgage Bonds, Series 114	4.60%	August 15, 2043	350	Repay commercial paper obligations and for general corporate purposes
PECO	First and Refunding Mortgage Bonds	1.20%	October 15, 2016	300	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	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	Partially refinance Notes due July 1, 2013 and for general corporate purposes

Table of Contents

During the year ended December 31, 2015, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon Corporate [a]	Senior Unsecured Notes	4.55%	June 15, 2015	$ 550
Exelon Corporate	Senior Notes	4.90%	June 15, 2015	800
Exelon Corporate	Senior Unsecured Notes [b]	3.95%	June 15, 2025	443
Exelon Corporate	Senior Unsecured Notes [b]	4.95%	June 15, 2035	167
Exelon Corporate	Senior Unsecured Notes [b]	5.10%	June 15, 2045	259
Exelon Corporate	Long Term Software License Agreement	3.95%	May 1, 2024	1
Generation [a]	Senior Unsecured Notes	4.55%	June 15, 2015	550
Generation	CEU Upstream Nonrecourse Debt [c]	LIBOR + 2.25%	January 14, 2019	9
Generation	AVSR DOE Nonrecourse Debt [c]	2.29% - 3.56%	January 5, 2037	23
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	3
Generation	Continental Wind Nonrecourse Debt [c]	6.00%	February 28, 2033	20
Generation	ExGen Texas Power Nonrecourse Debt [c]	LIBOR + 4.75%	September 8, 2021	5
Generation	ExGen Renewables I Nonrecourse Debt [c]	LIBOR + 4.25%	February 6, 2021	24
Generation	Constellation Solar Horizons Nonrecourse Debt [c]	2.56%	September 7, 2030	2
Generation	Sacramento PV Energy Nonrecourse Debt [c]	2.58%	December 31, 2030	2
Generation	Energy Efficiency Project	3.55%	November 15, 2016	19
ComEd	First Mortgage Bonds, Series 101	4.70%	April 15, 2015	260
BGE	Rate Stabilization Bonds	5.72%	April 1, 2016	75

(a) As part of the 2012 Constellation merger, Exelon and subsidiaries of Generation assumed intercompany loan agreements that mirrored the terms and amounts of external obligations held by Exelon, resulting in intercompany notes payable at Generation and Exelon Corporate.
(b) See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of the redemption of the Senior Unsecured Notes.
(c) See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.

On January 5, 2016, Generation paid down $5 million of principal of its 3.56% AVSR DOE Nonrecourse debt.

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

Company	Type	Interest Rate	Maturity	Amount
Generation	Senior Unsecured Notes	5.35%	January 15, 2014	$ 500
Generation	Pollution Control Notes	4.10%	July 1, 2014	20
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	20
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	3
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	18
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 18, 2021	2
Generation	AVSR DOE Nonrecourse Debt	2.33% - 3.55%	January 5, 2037	15
Generation	Clean Horizons Solar Nonrecourse Debt	2.56%	September 7, 2030	2
Generation	Sacramento Solar Nonrecourse Debt	2.56%	December 31, 2030	2
Generation	Energy Efficiency Project Financing	4.12%	December 31, 2015	12
ComEd	First 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

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 Constellation 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, which are eliminated in consolidation on Exelon s Consolidated Balance Sheets. The debentures were redeemed and the intercompany loan agreements repaid on June 15, 2013.

Table of Contents

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 for the year ended December 31, 2015, 2014 and 2013 by Registrant were as follows:

	2015	2014	2013
Exelon [(a)]	$ 1,105	$ 1,486	1,249
Generation [(a)]	2,474	1,066	625
ComEd	299	307	220
PECO	279	320	333
BGE [(b)]	171	13	13

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2015 and 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(b) Includes dividends paid on BGE s preference stock.

Quarterly dividends declared by the Exelon Board of Directors during the year ended December 31, 2015 and for the first quarter of 2016 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share
First Quarter 2015	January 27, 2015	February 13, 2015	March 10, 2015	$ 0.31
Second Quarter 2015	April 28, 2015	May 15, 2015	June 10, 2015	$ 0.31
Third Quarter 2015	July 28, 2015	August 14, 2015	September 10, 2015	$ 0.31
Fourth Quarter 2015	October 27, 2015	November 13, 2015	December 10, 2015	$ 0.31
First Quarter 2016 [(a)]	January 26, 2016	February 12, 2016	March 10, 2016	$ 0.31

(a) Exelon s Board of Directors approved a revised dividend policy. The approved policy would raise our dividend 2.5% each year for the next three years, beginning with the June 2016 dividend. The Board will take formal action to declare the next dividend in the second quarter.

Short-Term Borrowings. Short-term borrowings incurred (repaid) during 2015, 2014 and 2013 by Registrant were as follows:

	2015	2014	2013
Generation [(a)]	$	$ 17	$ 13
ComEd	(10)	120	184
BGE	90	(15)	135
Other [(b)]			

Exelon [a]	$ 80	$ 122	$ 332

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2015 activity includes CENG on a fully consolidated basis.
(b) Other primarily consists of corporate operations and BSC.

Table of Contents

Retirement of Long-Term Debt to Financing Affiliates. There were no retirements of long-term debt to financing affiliates during 2015, 2014 and 2013 by the Registrants.

Contributions from Parent/Member. Contributions from Parent/Member (Exelon) during 2015, 2014 and 2013 by Registrant were as follows:

	2015	2014	2013
Generation	$ 47	$ 53	$ 26
ComEd [(a)]	209	278	176
PECO	16	24	27
BGE	7		

(a) Additional contributions from parent or external debt financing may be required as a result of increased capital investment in infrastructure improvements and modernization pursuant to EIMA, transmission upgrades and expansions and Exelon s agreement to indemnify ComEd for any unfavorable after-tax impacts associated with ComEd s LKE tax matter.

Other. For the year ended December 31, 2015, other financing activities primarily consists of debt issuance costs. See Note 14 Debt and Credit Agreements 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 $8.4 billion in aggregate total commitments of which $6.9 billion was available as of December 31, 2015, and of which no financial institution has more than 7% of the aggregate commitments for Exelon, Generation, ComEd, PECO and BGE. The Registrants had access to the commercial paper market during 2015 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, 2015, it would have been required to provide incremental collateral of $2.0 billion to meet collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of $4.3 billion. If ComEd lost its investment grade credit ratings as of December 31, 2015, it would have been required to provide collateral of $31 million pursuant to PJM s credit policy and could have been required to provide incremental collateral of $19 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, 2015 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 $25 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, 2015 it would have been required to provide collateral of $6 million pursuant to PJM s credit policy and could have been required to provide collateral of $35 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

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants credit facilities and short term borrowing activity.

Other Credit Matters

Capital Structure. At December 31, 2015, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE
Long-term debt	47%	37%	43%	43%	34%
Long-term debt to affiliates [(a)]	1%	4%	1%	3%	5%
Common equity	51%		54%	54%	53%
Member s equity		59%			
Preference Stock					4%
Commercial paper and notes payable	1%		2%		4%

(a) Includes approximately $641 million, $205 million, $184 million and $252 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, 2015, in addition to the net contribution or borrowing as of December 31, 2015, are presented in the following table:

	Maximum Contributed	Maximum Borrowed	December 31, 2015 Contributed (Borrowed)
Generation	$ 3	$ 1,709	$ (1,252)
PECO		100	
BSC		413	(226)
Exelon Corporate	2,008		1,478

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 establish limits on the concentration of holdings in any one company and also in any one industry. See Note 16 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 have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in May 2017. 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. As of December 31, 2015, ComEd had $442 million available in long-term debt refinancing authority and $353 million available in new money long-term debt financing authority from the ICC. In November 2015, the PAPUC approved PECO s application for long-term financing for $2.5 billion, which is effective through December 31, 2018. As of December 31, 2015, PECO had $1.9 billion available in long-term debt financing authority from the PAPUC. As of December 31, 2015, BGE had $1.4 billion available in long-term financing authority from MDPSC.

As of December 31, 2015, ComEd, PECO and BGE had short-term financing authority from FERC, which expires on December 31, 2017, of $2.5 billion, $1.5 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 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. 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, 2015, Exelon had retained earnings of $12,068 million, including Generation s undistributed earnings of $2,701 million, ComEd s retained earnings of $978 million consisting of retained earnings appropriated for future dividends of $2,617 million partially offset by $1,639 million of unappropriated retained deficit, PECO s retained earnings of $780 million and BGE s retained earnings $1,320 million. See Note 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Table of Contents

Contractual Obligations

The following tables summarize the Registrants future estimated cash payments as of December 31, 2015 under existing contractual obligations, including payments due by period. See Note 23 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	**2016**	**2017-2018**	**2019-2020**	**Due 2021 and beyond**	**All Other**
Long-term debt [(a)]	$ 25,732	$ 1,483	$ 3,226	$ 4,275	$ 16,748	$
Interest payments on long-term debt [(b)]	14,459	1,146	2,122	1,863	9,328	
Liability and interest for uncertain tax positions [(c)]	860	860				
Capital leases	29	4	8	9	8	
Operating leases [(d)]	1,174	133	195	144	702	
Purchase power obligations [(e)]	1,692	506	717	212	257	
Fuel purchase agreements [(f)]	9,382	1,448	2,460	1,919	3,555	
Electric supply procurement [(f)]	1,563	993	570			
AEC purchase commitments [(f)]	6	1	2	3		
Curtailment services commitments [(f)]	99	37	55	7		
Long-term renewable energy and REC commitments [(g)]	1,443	76	155	165	1,047	
Other purchase obligations [(h)]	4,578	2,420	940	421	797	
Construction commitments [(i)]	1,272	821	451			
PJM regional transmission expansion commitments [(j)]	737	375	293	69		
Spent nuclear fuel obligation [(k)]	1,021				1,021	
Pension minimum funding requirement [(l)]	1,412	250	500	500	162	
Total contractual obligations	$ 65,459	$ 10,553	$ 11,694	$ 9,587	$ 33,625	$

(a) Includes $648 million due after 2021 to ComEd, PECO and BGE financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2015 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2015. Includes estimated interest payments due to ComEd, PECO and BGE financing trusts.

(c) In the event of a fully successful IRS challenge to Exelon s like-kind exchange position, Exelon would be required to either post a bond or pay the tax and interest for the tax years before the court to appeal the decision. If an adverse decision is reached in 2016, the potential tax and after-tax interest, exclusive of penalties, that could become payable may be as much as $860 million, of which approximately $300 million would be attributable to ComEd after consideration of Exelon s agreement to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd s equity, and the balance at Exelon. It is expected that Exelon s remaining tax years affected by the litigation will be settled following a final appellate decision which could take several years.

(d) Excludes Generation s contingent operating lease payments associated with contracted generation agreements. These amounts are included within purchase power obligations. Includes estimated cash payments for service fees related to PECO s meter reading operating lease.

(e) Purchase power obligations include contingent operating lease payments associated with contracted generation agreements. Amounts presented represent Generation s expected payments under these arrangements at December 31, 2015, including those related to CENG. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. These obligations do not include ComEd s SFCs as these contracts do not require purchases of fixed or minimum quantities. See Notes 3 Regulatory Matters

(f) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs and curtailment services.
(g) Primarily related to ComEd 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3 Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(h) Represents the future estimated value at December 31, 2015 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(i) Represents commitments for Generation s ongoing investments in renewables development, new natural gas and biomass generation construction. Amount includes $421 million of remaining commitments related to the construction of new combined-cycle gas turbine units in Texas. Achievement of commercial operations related to this project is expected in 2017.
(j) Under their operating agreements with PJM, ComEd, PECO and BGE are committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd s, PECO s and BGE s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(k) See Note 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding spent nuclear fuel obligations.
(l) These amounts represent Exelon s expected contributions to its qualified pension plans. The projected contributions reflect a funding strategy of contributing the greater of $250 million until the qualified plans are fully funded on an accumulated benefit obligation basis, and the minimum amounts under ERISA to avoid benefit restrictions and at-risk status thereafter. The remaining qualified pension plans contributions are generally based on the estimated minimum pension contributions required under ERISA and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2021 are not included. See Note 17 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

Generation

		Payment due within				
	Total	**2016**	**2017-2018**	**2019-2020**	**Due 2021 and beyond**	**All Other**
Long-term debt	$ 8,898	$ 87	$ 849	$ 2,575	$ 5,387	$
Interest payments on long-term debt [(a)]	5,452	424	792	684	3,552	
Capital leases	21	4	8	9		
Operating leases [(c)]	956	86	126	89	655	
Purchase power obligations [(d)]	1,692	506	717	212	257	
Fuel purchase agreements [(e)]	8,450	1,211	2,167	1,777	3,295	
Other purchase obligations [(f)]	2,193	928	392	225	648	
Construction commitments [(g)]	1,272	821	451			
Spent nuclear fuel obligation [(b)]	1,021				1,021	
Total contractual obligations	$ 29,955	$ 4,067	$ 5,502	$ 5,571	$ 14,815	$

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2015 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2015.
(b) See Note 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding spent nuclear fuel obligations.
(c) Excludes Generation s contingent operating lease payments associated with contracted generation agreements.
(d) Purchase power obligations include contingent operating lease payments associated with contracted generation agreements. Amounts presented represent Generation s expected payments under these arrangements at December 31, 2015. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature.
(e) Represents commitments to purchase fuel supplies for nuclear and fossil generation.

(f) Represents the future estimated value at December 31, 2015 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(g) Represents commitments for Generation s ongoing investments in renewables development, new natural gas and biomass generation construction. Amount includes $421 million of remaining commitments related to the construction of new combined-cycle gas turbine units in Texas. Achievement of commercial operations related to this project is expected in 2017.

ComEd

	Payment due within					
	Total	2016	2017-2018	2019-2020	Due 2021 and beyond	All Other
Long-term debt [(a)]	$ 6,765	$ 665	$ 1,265	$ 800	$ 4,035	$
Interest payments on long-term debt [(b)]	4,597	297	523	420	3,357	
Liability and interest for uncertain tax positions [(c)]	300	300				
Capital leases	8				8	
Operating leases	37	14	14	8	1	
Electric supply procurement	739	453	286			
Long-term renewable energy and associated REC commitments [(d)]	1,444	76	156	165	1,047	
Other purchase obligations [(e)]	699	565	94	39	1	
PJM regional transmission expansion commitments [(f)]	297	204	87	6		
Total contractual obligations	$ 14,886	$ 2,574	$ 2,425	$ 1,438	$ 8,449	$

(a) Includes $206 million due after 2021 to a ComEd financing trust.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2015 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2015. Includes estimated interest payments due to the ComEd financing trust.
(c) In the event of a fully successful IRS challenge to Exelon s like-kind exchange position, Exelon would be required to either post a bond or pay the tax and interest for the tax years before the court to appeal the decision. If an adverse decision is reached in 2016, the potential tax and after-tax interest, exclusive of penalties, that could become payable may be as much as $860 million, of which approximately $300 million would be attributable to ComEd after consideration of Exelon s agreement to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd s equity, and the balance at Exelon. It is expected that Exelon s remaining tax years affected by the litigation will be settled following a final appellate decision which could take several years.
(d) Primarily related to ComEd 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3 Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(e) Represents the future estimated value at December 31, 2015 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(f) Under its operating agreement with PJM, ComEd is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

PECO

	Payment due within					
	Total	2016	2017-2018	2019-2020	Due 2021 and beyond	All Other
Long-term debt [(a)]	$ 2,784	$ 300	$ 500	$	$ 1,984	$
Interest payments on long-term debt [(b)]	1,771	115	207	176	1,273	
Operating leases	12	3	5	4		
Fuel purchase agreements [(c)]	357	125	137	35	60	
Electric supply procurement [(c)]	622	516	106			
AEC purchase commitments [(c)]	9	2	4	3		
Other purchase obligations [(d)]	215	174	18	22	1	
PJM regional transmission expansion commitments [(e)]	67	31	32	4		
Total contractual obligations	$ 5,837	$ 1,266	$ 1,009	$ 244	$ 3,318	$

(a) Includes $184 million due after 2021 to PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2014 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs.
(d) Represents the future estimated value at December 31, 2015 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(e) Under its operating agreement with PJM, PECO is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PECO s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

BGE

	Payment due within					
	Total	2016	2017-2018	2019-2020	Due 2021 and beyond	All Other
Long-term debt [(a)]	$ 2,128	$ 378	$ 42	$	$ 1,708	$
Interest payments on long-term debt [(b)]	1,353	82	159	159	953	
Operating leases	65	12	19	15	19	
Fuel purchase agreements [(d)]	575	112	156	107	200	
Electric supply procurement [(d)]	1,427	860	567			
Curtailment services commitments [(d)]	99	37	55	7		
Other purchase obligations [(e)]	635	408	208	17	2	
PJM regional transmission expansion commitments [(c)]	373	140	174	59		
Total contractual obligations	$ 6,655	$ 2,029	$ 1,380	$ 364	$ 2,882	$

(a) Includes $258 million due after 2021 to the BGE financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2015 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Under its operating agreement with PJM, BGE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent BGE s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 Regulatory Matters of the Combined

Notes to Consolidated Financial Statements.

(d) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and curtailment services.

(e) Represents the future estimated value at December 31, 2015 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

Table of Contents

See Note 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants other commitments potentially triggered by future events.

For additional information regarding:

- commercial paper, see Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- long-term debt, see Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- liabilities related to uncertain tax positions, see Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- operating leases and rate relief commitments, see Note 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- the nuclear decommissioning and SNF obligations, see Notes 16 Asset Retirement Obligations and 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements.
- variable interest entities, see Note 2 Variable Interest Entities of the Combined Notes to Consolidated Financial Statements.
- nuclear insurance, see Note 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- new accounting pronouncements, see Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon s RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities.

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

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

Generation

Normal Operations and Hedging Activities. Electricity available from Generation s owned or contracted generation supply in excess of Generation s obligations to customers, including portions of ComEd s, PECO s and BGE s retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2016 through 2018.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation s owned and contracted generation positions which have not been hedged. Exelon s hedging program involves the hedging of commodity risk for Exelon s expected generation, typically on a ratable basis over a three year period. As of December 31, 2015, the proportion of expected generation hedged is 90%-93%, 60%-63% and 28%-31% for 2016, 2017 and 2018, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. 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 Generation s sales to ComEd, PECO and BGE to serve their retail load.

A portion of Generation s hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation s entire non-proprietary trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on December 31, 2015, market conditions and hedged position would be a decrease in pre-tax net income of approximately $50 million, $400 million and $725 million, respectively, for 2016, 2017 and 2018. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation s portfolio.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon s RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon s RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 7,310 GWh, 10,571 GWh, and 8,762 GWh for the years ended December 31, 2015, 2014 and 2013 respectively, are a complement to Generation s energy marketing portfolio, but represent a small portion of Generation s overall revenue from energy marketing activities. Proprietary trading portfolio activity for the year ended December 31, 2015, resulted in pre-tax gains of $1 million due to net mark-to-market losses of $8 million and realized gains of $9 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $0.2 million of exposure during the year. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to

Table of Contents

Generation s total Revenue net of purchase power and fuel expense from continuing operations for the year ended December 31, 2015 of $9,114 million.

Fuel Procurement. Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrates supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation s procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 50% of Generation s uranium concentrate requirements from 2016 through 2020 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 positions. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information regarding uranium and coal supply agreement matters.

ComEd

The financial swap contract between Generation and ComEd was deemed prudent by the Illinois Settlement Legislation, thereby ensuring that ComEd would be entitled to receive full cost recovery in rates. The change in fair value each period was recorded by ComEd with an offset to a regulatory asset or liability. This financial swap contract between Generation and ComEd expired on May 31, 2013. All realized impacts have been included in Generation s and ComEd s results of operations.

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC s Order on December 19, 2012, ComEd s commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC s December 18, 2013 Order approved the reduction of ComEd s commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014. See Note 3 Regulatory Matters and Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3 Regulatory Matters of the Combined Notes to the Consolidated Financial Statements. PECO has certain full requirements contracts and block contracts, which are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

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

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE s MDPSC-approved SOS program. BGE s full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance and as a result, are accounted for on an accrual basis of accounting. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE s financial position. However, under BGE s market-based rates incentive mechanism, BGE s actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE s actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities

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

Table of Contents

The following table provides detail on changes in Exelon s, Generation s, and ComEd s commodity mark-to-market net asset or liability balance sheet position from January 1, 2014 to December 31, 2015. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings, as well as the settlements from OCI to earnings and changes in fair value for the cash flow hedging activities that are recorded in Accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2015 and December 31, 2014.

	Generation	ComEd	Exelon
Total mark-to-market energy contract net assets (liabilities) at January 1, 2014 [a]	$ 1,047	$ (193)	$ 854
Contracts acquired at merger date [c]	128		128
Total change in fair value during 2014 of contracts recorded in result of operations	(608)		(608)
Reclassification to realized at settlement of contracts recorded in results of operations	(21)		(21)
Reclassification to realized at settlement from accumulated OCI	(195)		(195)
Changes in fair value energy derivatives [b]		(14)	(14)
Changes in allocated collateral	1,503		1,503
Changes in net option premium paid/(received)	(38)		(38)
Option premium amortization	(122)		(122)
Other balance sheet reclassifications [d]	18		18
Total mark-to-market energy contract net assets (liabilities) at December 31, 2014 [a]	1,712	(207)	1,505
Total change in fair value during 2015 of contracts recorded in result of operations	412		412
Reclassification to realized at settlement of contracts recorded in results of operations	(168)		(168)
Reclassification to realized at settlement from accumulated OCI	(2)		(2)
Changes in fair value energy derivatives [b]		(40)	(40)
Changes in allocated collateral	(172)		(172)
Changes in net option premium paid/(received)	(58)		(58)
Option premium amortization	(21)		(21)
Other balance sheet reclassifications [d]	50		50
Total mark-to-market energy contract net assets (liabilities) at December 31, 2015 [a]	$ 1,753	$ (247)	$ 1,506

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

(b) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2015 and 2014, ComEd recorded a regulatory liability of $247 million and $207 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. Includes $55 million of decreases in fair value and an increase for realized losses due to settlements off $(15) million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2015. Includes $13 million of decreases in fair value and a reduction for realized gains due to settlements of $1 million for the year ended December 31, 2014.

(c) Includes $81 million of fair value from contracts acquired and $47 million of cash collateral as a result of the Integrys acquisition.

(d) Other balance sheet reclassifications include derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums.

Table of Contents

Fair Values

The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants commodity contract net assets (liabilities) net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 12 Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						Total
	2016	2017	2018	2019	2020	2021 and Beyond	Fair Value
Normal Operations, Commodity derivative contracts [(a)(b)]:							
Actively quoted prices (Level 1)	$ 37	$ 27	$ (19)	$ (19)	$ (7)	$	$ 19
Prices provided by external sources (Level 2)	540	165	(8)	(8)	(6)		683
Prices based on model or other valuation methods (Level 3) [(c)]	572	255	95	(26)	(23)	(69)	804
Total	$ 1,149	$ 447	$ 68	$ (53)	$ (36)	$ (69)	$ 1,506

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $1,234 million at December 31, 2015.
(c) Includes ComEd s net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						Total
	2016	2017	2018	2019	2020	2021 and Beyond	Fair Value
Normal Operations, Commodity derivative contracts [(a)(b)]:							
Actively quoted prices (Level 1)	$ 37	$ 27	$ (19)	$ (19)	$ (7)	$	$ 19
Prices provided by external sources (Level 2)	540	165	(8)	(8)	(6)		683
Prices based on model or other valuation methods (Level 3)	595	276	116	(5)	(1)	70	1,051
Total	$ 1,172	$ 468	$ 89	$ (32)	$ (14)	$ 70	$ 1,753

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b)

Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $1,234 million at December 31, 2015.

Table of Contents

ComEd

	Maturities Within						
	2016	2017	2018	2019	2020	2021 and Beyond	Fair Value
Prices based on model or other valuation methods (Level 3) [(a)]	$ (23)	$ (21)	$ (21)	$ (21)	$ (22)	$ (139)	$ (247)

(a) Represents ComEd s net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

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

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation s credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2015. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company s credit risk by credit rating of the counterparties. The figures in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE, and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO and BGE of $15 million, $36 million and $31 million, respectively. See Note 26 Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Rating as of December 31, 2015	Total Exposure Before Credit Collateral	Credit Collateral [(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,397	$ 50	$ 1,347	1	$ 432
Non-investment grade	67	25	42		
No external ratings					
Internally rated investment grade	521		521		
Internally rated non-investment grade	77	7	70		
Total	$ 2,062	$ 82	$ 1,980	1	$ 432

Table of Contents

	Maturity of Credit Risk Exposure			
Rating as of December 31, 2015	**Less than 2 Years**	**2-5 Years**	**Exposure Greater than 5 Years**	**Total Exposure Before Credit Collateral**
Investment grade	$ 1,036	$ 343	$ 18	$ 1,397
Non-investment grade	40	19	8	67
No external ratings				
Internally rated investment grade	452	46	23	521
Internally rated non-investment grade	71	6		77
Total	$ 1,599	$ 414	$ 49	$ 2,062

Net Credit Exposure by Type of Counterparty	**As of December 31, 2015**
Financial institutions	$ 187
Investor-owned utilities, marketers, power producers	886
Energy cooperatives and municipalities	872
Other	35
Total	$ 1,980

(a) As of December 31, 2015, credit collateral held from counterparties where Generation had credit exposure included $13 million of cash and $69 million of letters of credit.

ComEd

Credit risk for ComEd is managed by credit and collection policies, which are consistent with state regulatory requirements. ComEd is currently obligated to provide service to all electric customers within its franchised territory. ComEd records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. The Illinois Settlement Legislation prohibits utilities, including ComEd, from terminating electric service to a residential electric space heat customer due to nonpayment between December 1 of any year through March 1 of the following year. ComEd s ability to disconnect non space-heating residential customers is also impacted by certain weather restrictions, at any time of year, under the Illinois Public Utilities Act. ComEd will monitor the impact of its disconnection practices and will make any necessary adjustments to the provision for uncollectible accounts. ComEd did not have any customers representing over 10% of its revenues as of December 31, 2015. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding ComEd s recently approved tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense.

ComEd s power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd s net credit exposure. ComEd s counterparty credit risk is mitigated by its ability to

176

recover realized energy costs through customer rates. As of December 31, 2015, ComEd s credit exposure to energy suppliers was immaterial.

PECO

Credit risk for PECO is managed by credit and collection policies, which are consistent with state regulatory requirements. PECO is currently obligated to provide service to all retail electric customers within its franchised territory. PECO records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with PAPUC regulations, after November 30 and before April 1, an electric distribution utility or natural gas distribution utility shall not terminate service to customers with household incomes at or below 250% of the Federal poverty level. PECO s provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in PAPUC regulations. PECO did not have any customers representing over 10% of its revenues as of December 31, 2015.

PECO s supplier master agreements that govern the terms of its DSP Program contracts, which define a supplier s performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier s lowest credit rating from the major credit rating agencies and the supplier s tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier s unsecured credit limit. As of December 31, 2015, PECO had no net credit exposure with suppliers.

PECO does not obtain cash collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2015, PECO s credit exposure under its natural gas supply and asset management agreements with investment grade suppliers was immaterial.

BGE

Credit risk for BGE is managed by credit and collection policies, which are consistent with state regulatory requirements. BGE is currently obligated to provide service to all electric customers within its franchised territory. BGE records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. BGE will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for uncollectible accounts policy. MDPSC regulations prohibit BGE from terminating service to residential customers due to nonpayment from November 1 through March 31 if the forecasted temperature is 32 degrees or below for the subsequent 72 hour period. BGE is also prohibited by the Public Utilities Article of the Annotated Code of Maryland and MDPSC regulations from terminating service to residential customers due to nonpayment if the forecasted temperature is 95 degrees or above for the subsequent 72 hour period. BGE did not have any customers representing over 10% of its revenues as of December 31, 2015.

BGE s full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier s performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier s lowest credit rating from the major credit rating agencies and the supplier s tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day

a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier s unsecured credit limit. The seller s credit exposure is calculated each business day. As of December 31, 2015, BGE had no net credit exposure with suppliers.

BGE s regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE s recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers demands, which are not covered by the gas cost adjustment clause. At December 31, 2015, BGE had credit exposure of $4 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

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

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, natural gas and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation s net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation transacts output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon s and Generation s results of operations, cash flows and financial position. As market prices rise above or fall below contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

As of December 31, 2015, Generation had cash collateral of $1,267 million posted and cash collateral held of $21 million for external counterparties with derivative positions, of which $1,234 million and $9 million in net cash collateral deposits were offset against energy derivatives and interest rate and foreign exchange derivatives related to underlying energy contracts, respectively. As of December 31, 2015, $3 million of cash collateral deposits was not offset against net derivative positions because it was not associated with energy-related derivatives or as of the balance sheet date there were no positions to offset. As of December 31, 2014, Generation had cash collateral posted of $1,497 million and cash collateral held of $77 million for external counterparties with derivative positions, of which $1,406 million and $6 million in net cash collateral deposits were offset against

Table of Contents

energy derivatives and interest rate and foreign exchange derivatives related to underlying energy contracts, respectively. As of December 31, 2014, $8 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives or as the balance sheet date there were no positions to offset. See Note 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of December 31, 2015, ComEd held no collateral from suppliers in association with standard block energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for renewable energy contracts. See Note 3 Regulatory Matters and Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

PECO

As of December 31, 2015, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of December 31, 2015, BGE was not required to post collateral under its natural gas procurement contracts nor was it holding collateral under its electric supply and natural gas procurement contracts. See Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

RTOs and ISOs (Exelon, Generation, ComEd, PECO and BGE)

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

Exchange Traded Transactions (Exelon and Generation)

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

Table of Contents

Long-Term Leases (Exelon)

Exelon s Consolidated Balance Sheet, as of December 31, 2015, included a $352 million net investment in coal-fired plants in Georgia subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of $639 million, less unearned income of $287 million. As of December 31, 2014, Exelon s Consolidated Balance Sheet included a $361 million net investment in coal-fired plants in Georgia subject to long-term leases, which represented the estimated residual value of leased assets at the end of the respective lease terms of $685 million, less unearned income of $324 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessee does not exercise the fixed purchase options, Exelon has the ability to operate the stations and keep or market the power itself or require the lessee to arrange for a third-party to bid on a service contract for a period following the lease term. Exelon will be subject to residual value risk if the lessee does not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon s exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures. Management regularly evaluates the creditworthiness of Exelon s counterparties to these long-term leases. Exelon monitors the continuing credit quality of the credit enhancement party.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and, if the review indicates a fair value below the carrying value and the decline is determined to be other than temporary, must record an impairment charge in the period the estimate changed. Based on the annual review performed in the second quarters of 2015 and 2014, the estimated residual value of Exelon s direct financing leases for the Georgia generating stations experienced other than temporary declines given increases in estimated long-term operating and maintenance costs in the 2015 annual review and reduced long-term energy and capacity price expectations in the 2014 annual review. As a result, Exelon recorded a $24 million pre-tax impairment charge in 2015 and 2014 for these stations. See Note 8 Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for further information.

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2015, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $738 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $6 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2015. 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.

Table of Contents

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation s nuclear plants. As of December 31, 2015, Generation s decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation s NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $454 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

Table of Contents

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

Generation

General

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. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. These segments are discussed in further detail in ITEM 1. BUSINESS Exelon Generation Company, LLC of this Form 10-K.

Executive Overview

A discussion of items pertinent to Generation s executive overview is set forth under ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Exelon Corporation Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2015 Compared To Year Ended December 31, 2014 and Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

A discussion of Generation s results of operations for 2015 compared to 2014 and 2014 compared to 2013 is set forth under Results of Operations Generation in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

Generation s business is capital intensive and requires considerable capital resources. Generation s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, participation in the intercompany money pool or capital contributions from Exelon. Generation s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has access to credit facilities in the aggregate of $5.7 billion that Generation currently utilizes to support its commercial paper program and to issue letters of credit.

See the EXELON CORPORATION Liquidity and Capital Resources and Note 14 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund Generation s capital requirements, including construction, retirement of debt, the payment of distributions to Exelon, contributions to Exelon s pension plans and investments in new and existing ventures. Future acquisitions could require external financing or borrowings or capital contributions from Exelon.

Cash Flows from Operating Activities

A discussion of items pertinent to Generation s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Table of Contents

Cash Flows from Investing Activities

A discussion of items pertinent to Generation s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Generation s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Generation is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Generation s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd, PECO and BGE Critical Accounting Policies and Estimates above for a discussion of Generation s critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Generation

Generation is exposed to market risks associated with commodity price, credit, interest rates and equity price. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

Table of Contents

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

ComEd

General

ComEd operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in northern Illinois, including the City of Chicago. This segment is discussed in further detail in ITEM 1. BUSINESS ComEd of this Form 10-K.

Executive Overview

A discussion of items pertinent to ComEd s executive overview is set forth under EXELON CORPORATION Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 and Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

A discussion of ComEd s results of operations for 2015 compared to 2014 and for 2014 compared to 2013 is set forth under Results of Operations ComEd in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

ComEd s business is capital intensive and requires considerable capital resources. ComEd s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ComEd s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2015, ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion. See the Credit Matters section of Liquidity and Capital Resources for additional discussion.

See the EXELON CORPORATION Liquidity and Capital Resources and Note 14 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund ComEd s capital requirements, including construction, retirement of debt, and contributions to Exelon s pension plans. Additionally, ComEd operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ComEd s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to ComEd s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Table of Contents

Cash Flows from Financing Activities

A discussion of items pertinent to ComEd s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ComEd is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ComEd s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd, PECO and BGE Critical Accounting Policies and Estimates above for a discussion of ComEd s critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ComEd

ComEd is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

Table of Contents

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

PECO

General

PECO operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution service in Pennsylvania in the counties surrounding the City of Philadelphia. This segment is discussed in further detail in ITEM 1. BUSINESS PECO of this Form 10-K.

Executive Overview

A discussion of items pertinent to PECO s executive overview is set forth under EXELON CORPORATION Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 and Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

A discussion of PECO s results of operations for 2015 compared to 2014 and for 2014 compared to 2013 is set forth under Results of Operations PECO in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

PECO s business is capital intensive and requires considerable capital resources. PECO s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or participation in the intercompany money pool. PECO s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At December 31, 2015, PECO had access to a revolving credit facility with aggregate bank commitments of $600 million. See the Credit Matters section of Liquidity and Capital Resources for additional discussion.

Capital resources are used primarily to fund PECO s capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon s pension plans. Additionally, PECO operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PECO s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to PECO s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Table of Contents

Cash Flows from Financing Activities

A discussion of items pertinent to PECO s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PECO is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PECO s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd, PECO and BGE Critical Accounting Policies and Estimates above for a discussion of PECO s critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PECO

PECO is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

187

Table of Contents

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

BGE

General

BGE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution service in central Maryland, including the City of Baltimore. This segment is discussed in further detail in ITEM 1. BUSINESS BGE of this Form 10-K.

Executive Overview

A discussion of items pertinent to BGE s executive overview is set forth under EXELON CORPORATION Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 and Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

A discussion of BGE s results of operations for 2015 compared to 2014 and for 2014 compared to 2013 is set forth under Results of Operations BGE in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

BGE s business is capital intensive and requires considerable capital resources. BGE s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. BGE s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where BGE no longer has access to the capital markets at reasonable terms, BGE has access to a revolving credit facility. At December 31, 2015, BGE had access to a revolving credit facility with aggregate bank commitments of $600 million. See the Credit Matters section of Liquidity and Capital Resources for additional discussion.

Capital resources are used primarily to fund BGE s capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon s pension plans. Additionally, BGE operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to BGE s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to BGE s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Table of Contents

Cash Flows from Financing Activities

A discussion of items pertinent to BGE s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to BGE is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of BGE s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd, PECO and BGE Critical Accounting Policies and Estimates above for a discussion of BGE s critical accounting policies and estimates.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BGE

BGE is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

189

Table of Contents

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management s Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Exelon s management conducted an assessment of the effectiveness of Exelon s internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon s management concluded that, as of December 31, 2015, Exelon s internal control over financial reporting was effective.

The effectiveness of Exelon s internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 10, 2016

Table of Contents

Management s Report on Internal Control Over Financial Reporting

The management of Exelon Generation Company, LLC (Generation) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Generation s management conducted an assessment of the effectiveness of Generation s internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Generation s management concluded that, as of December 31, 2015, Generation s internal control over financial reporting was effective.

The effectiveness of Generation s internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 10, 2016

Table of Contents

Management s Report on Internal Control Over Financial Reporting

The management of Commonwealth Edison Company (ComEd) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

ComEd s management conducted an assessment of the effectiveness of ComEd s internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ComEd s management concluded that, as of December 31, 2015, ComEd s internal control over financial reporting was effective.

The effectiveness of ComEd s internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 10, 2016

Table of Contents

Management s Report on Internal Control Over Financial Reporting

The management of PECO Energy Company (PECO) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

PECO s management conducted an assessment of the effectiveness of PECO s internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PECO s management concluded that, as of December 31, 2015, PECO s internal control over financial reporting was effective.

The effectiveness of PECO s internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 10, 2016

Table of Contents

Management s Report on Internal Control Over Financial Reporting

The management of Baltimore Gas and Electric Company (BGE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

BGE s management conducted an assessment of the effectiveness of BGE s internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, BGE s management concluded that, as of December 31, 2015, BGE s internal control over financial reporting was effective.

The effectiveness of BGE s internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 10, 2016

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Exelon Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Corporation (the Company) and its subsidiaries at December 31, 2015 and 2014 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Chicago, Illinois

February 10, 2016

195

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Exelon Generation Company, LLC:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Generation Company, LLC (the Company) and its subsidiaries at December 31, 2015 and 2014 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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/s/ PricewaterhouseCoopers LLP

Baltimore, Maryland

February 10, 2016

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Commonwealth Edison Company (the Company) and its subsidiaries at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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/s/ PricewaterhouseCoopers LLP

Chicago, Illinois

February 10, 2016

197

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of PECO Energy Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of PECO Energy Company (the Company) and its subsidiaries at December 31, 2015 and 2014 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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/s/ PricewaterhouseCoopers LLP

Philadelphia, Pennsylvania

February 10, 2016

198

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Baltimore Gas and Electric Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company (the Company) and its subsidiaries at December 31, 2015 and 2014 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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/s/ PricewaterhouseCoopers LLP

Baltimore, Maryland

February 10, 2016

Table of Contents

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Table of Contents

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	For the Years Ended December 31, 2015	2014	2013
Operating revenues			
Competitive businesses revenues	$ 18,395	$ 16,637	$ 14,277
Rate-regulated utility revenues	11,052	10,792	10,611
Total operating revenues	29,447	27,429	24,888
Operating expenses			
Competitive businesses purchased power and fuel	10,007	9,369	6,928
Rate-regulated utility purchased power and fuel	3,077	3,103	2,540
Purchased power and fuel from affiliates		531	1,256
Operating and maintenance	8,322	8,568	7,270
Depreciation and amortization	2,450	2,314	2,153
Taxes other than income	1,200	1,154	1,095
Total operating expenses	25,056	25,039	21,242
Equity in (losses) earnings of unconsolidated affiliates		(20)	10
Gain on sales of assets	18	437	13
Gain on consolidation and acquisition of businesses		289	
Operating income	4,409	3,096	3,669
Other income and (deductions)			
Interest expense, net	(992)	(1,024)	(1,315)
Interest expense to affiliates, net	(41)	(41)	(41)
Other, net	(46)	455	460
Total other income and (deductions)	(1,079)	(610)	(896)
Income before income taxes	3,330	2,486	2,773
Income taxes	1,073	666	1,044
Equity in losses of unconsolidated affiliates	(7)		
Net income	2,250	1,820	1,729
Net income (loss) attributable to noncontrolling interest and preference stock dividends	(19)	197	10
Net income attributable to common shareholders	$ 2,269	$ 1,623	$ 1,719
Comprehensive income, net of income taxes			
Net income	$ 2,250	$ 1,820	$ 1,729
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	(46)	(30)	
Actuarial loss reclassified to periodic benefit cost	220	147	208
Pension and non-pension postretirement benefit plan valuation adjustment	(99)	(497)	669
Unrealized gain (loss) on cash flow hedges	9	(148)	(248)

Unrealized gain on marketable securities		1	2
Unrealized gain (loss) on equity investments	(3)	8	106
Unrealized loss on foreign currency translation	(21)	(9)	(10)
Reversal of CENG equity method AOCI		(116)	
Other comprehensive income (loss)	60	(644)	727
Comprehensive income	$ 2,310	$ 1,176	$ 2,456
Average shares of common stock outstanding:			
Basic	890	860	856
Diluted	893	864	860
Earnings per average common share:			
Basic	$ 2.55	$ 1.89	$ 2.01
Diluted	$ 2.54	$ 1.88	$ 2.00
Dividends per common share	$ 1.24	$ 1.24	$ 1.46

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2015	2014	2013
Cash flows from operating activities			
Net income	$ 2,250	$ 1,820	$ 1,729
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	3,987	3,868	3,779
Impairment of long-lived assets	36	687	171
Gain on consolidation and acquisition of businesses		(296)	
Gain on sales of assets	(18)	(437)	(13)
Deferred income taxes and amortization of investment tax credits	752	502	119
Net fair value changes related to derivatives	(367)	716	(445)
Net realized and unrealized losses (gains) on nuclear decommissioning trust fund investments	131	(210)	(170)
Other non-cash operating activities	1,109	1,054	718
Changes in assets and liabilities:			
Accounts receivable	240	(318)	(97)
Inventories	4	(380)	(100)
Accounts payable and accrued expenses	(121)	49	(116)
Option premiums received (paid), net	58	38	(36)
Collateral received (posted), net	347	(1,719)	215
Income taxes	97	(143)	883
Pension and non-pension postretirement benefit contributions	(502)	(617)	(422)
Other assets and liabilities	(387)	(157)	128
Net cash flows provided by operating activities	7,616	4,457	6,343
Cash flows from investing activities			
Capital expenditures	(7,624)	(6,077)	(5,395)
Proceeds from termination of direct financing lease investment		335	
Proceeds from nuclear decommissioning trust fund sales	6,895	7,396	4,217
Investment in nuclear decommissioning trust funds	(7,147)	(7,551)	(4,450)
Cash and restricted cash acquired from consolidations and acquisitions		140	
Acquisitions of businesses	(40)	(386)	
Proceeds from sales of long-lived assets	147	1,719	32
Proceeds from sales of investments		7	22
Purchases of investments		(3)	(4)
Change in restricted cash	66	(104)	(43)
Distribution from CENG		13	115
Other investing activities	(119)	(88)	112
Net cash flows used in investing activities	(7,822)	(4,599)	(5,394)
Cash flows from financing activities			
Payment of accounts receivable agreement			(210)
Changes in short-term borrowings	80	122	332
Issuance of long-term debt	6,709	3,463	2,055
Retirement of long-term debt	(2,687)	(1,545)	(1,589)
Issuance of common stock	1,868		

Redemption of preferred securities			(93)
Distributions to noncontrolling interest of consolidated VIE		(421)	
Dividends paid on common stock	(1,105)	(1,065)	(1,249)
Proceeds from employee stock plans	32	35	47
Other financing activities	(67)	(178)	(119)
Net cash flows provided by (used in) financing activities	4,830	411	(826)
Increase in cash and cash equivalents	4,624	269	123
Cash and cash equivalents at beginning of period	1,878	1,609	1,486
Cash and cash equivalents at end of period	$ 6,502	$ 1,878	$ 1,609

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2015	2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 6,502	$ 1,878
Restricted cash and cash equivalents	205	271
Accounts receivable, net		
Customer	3,187	3,482
Other	912	1,227
Mark-to-market derivative assets	1,365	1,279
Unamortized energy contract assets	86	254
Inventories, net		
Fossil fuel	462	579
Materials and supplies	1,104	1,024
Regulatory assets	759	847
Assets held for sale	4	147
Other	748	865
Total current assets	15,334	11,853
Property, plant and equipment, net	57,439	52,170
Deferred debits and other assets		
Regulatory assets	6,065	6,076
Nuclear decommissioning trust funds	10,342	10,537
Investments	639	544
Goodwill	2,672	2,672
Mark-to-market derivative assets	758	773
Unamortized energy contract assets	484	549
Pledged assets for Zion Station decommissioning	206	319
Other	1,445	923
Total deferred debits and other assets	22,611	22,393
Total assets [(a)]	$ 95,384	$ 86,416

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2015	2014
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 533	$ 460
Long-term debt due within one year	1,500	1,802
Accounts payable	2,883	3,048
Accrued expenses	2,376	1,539
Payables to affiliates	8	8
Regulatory liabilities	369	310
Mark-to-market derivative liabilities	205	234
Unamortized energy contract liabilities	100	238
Renewable energy credit obligation	302	192
Other	842	931
Total current liabilities	9,118	8,762
Long-term debt	23,645	19,212
Long-term debt to financing trusts	641	641
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,776	12,778
Asset retirement obligations	8,585	7,295
Pension obligations	3,385	3,366
Non-pension postretirement benefit obligations	1,618	1,742
Spent nuclear fuel obligation	1,021	1,021
Regulatory liabilities	4,201	4,550
Mark-to-market derivative liabilities	374	403
Unamortized energy contract liabilities	117	211
Payable for Zion Station decommissioning	90	155
Other	1,491	2,147
Total deferred credits and other liabilities	34,658	33,668
Total liabilities [(a)]	68,062	62,283
Commitments and contingencies		
Contingently redeemable noncontrolling interest	28	
Shareholders equity		
Common stock (No par value, 2000 shares authorized, 920 shares and 860 shares outstanding at December 31, 2015 and 2014, respectively)	18,676	16,709
Treasury stock, at cost (35 shares at December 31, 2015 and 2014, respectively)	(2,327)	(2,327)
Retained earnings	12,068	10,910
Accumulated other comprehensive loss, net	(2,624)	(2,684)
Total shareholders equity	25,793	22,608
BGE preference stock not subject to mandatory redemption	193	193
Noncontrolling interest	1,308	1,332

Total equity	27,294	24,133
Total liabilities and shareholders equity	$ 95,384	$ 86,416

(a) Exelon s consolidated assets include $8,268 million and $8,159 million at December 31, 2015 and December 31, 2014, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon s consolidated liabilities include $3,264 million and $2,728 million at December 31, 2015 and December 31, 2014, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 2 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Changes in Shareholders Equity

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Non-controlling Interest	Preferred and Preference Stock	Total Shareholders Equity
Balance, December 31, 2012	889,525	$ 16,632	$ (2,327)	$ 9,893	$ (2,767)	$ 106	$ 193	$ 21,730
Net income (loss)				1,719		(10)	20	1,729
Long-term incentive plan activity	1,445	81						81
Employee stock purchase plan issuances	1,064	28						28
Common stock dividends				(1,254)				(1,254)
Consolidated VIE dividend to noncontrolling interest						(63)		(63)
Deconsolidation of VIE						(18)		(18)
Redemption of preferred securities							(6)	(6)
Preferred and preference stock dividends							(14)	(14)
Other comprehensive income, net of income taxes					727			727
Balance, December 31, 2013	892,034	$ 16,741	$ (2,327)	$ 10,358	$ (2,040)	$ 15	$ 193	$ 22,940
Net income				1,623		184	13	1,820
Long-term incentive plan activity	1,574	72						72
Employee stock purchase plan issuances	960	35						35
Tax benefit on stock compensation		(8)						(8)
Acquisition of noncontrolling interest		(2)				6		4
Common stock dividends				(1,071)				(1,071)
Preferred and preference stock dividends							(13)	(13)
Fair value of financing contract payments		(131)						(131)
Noncontrolling interest established upon consolidation of CENG						1,548		1,548
Transfer of CENG pension and non-pension postretirement benefit obligations		2						2
Consolidated VIE dividend to noncontrolling interest						(421)		(421)
Reversal of CENG equity method AOCI, net of income taxes					(116)			(116)
Other comprehensive loss, net of income taxes					(528)			(528)
Balance, December 31, 2014	894,568	$ 16,709	$ (2,327)	$ 10,910	$ (2,684)	$ 1,332	$ 193	$ 24,133
Net income (loss)				2,269		(32)	13	2,250
Long-term incentive plan activity	1,430	70						70
Employee stock purchase plan issuances	1,170	32						32
Issuance of common stock	57,500	1,868						1,868
Tax benefit on stock compensation		(3)						(3)
Acquisition of noncontrolling interest						4		4
Adjustment of contingently redeemable noncontrolling interest due to release of contingency						4		4
Common stock dividends				(1,111)				(1,111)
Preferred and preference stock dividends							(13)	(13)
Other comprehensive loss, net of income taxes					60			60
Balance, December 31, 2015	954,668	$ 18,676	$ (2,327)	$ 12,068	$ (2,624)	$ 1,308	$ 193	$ 27,294

See the Combined Notes to Consolidated Financial Statements

Table of Contents

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Table of Contents

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	2015	For the Years Ended December 31, 2014	2013
Operating revenues			
Operating revenues	$ 18,386	$ 16,614	$ 14,207
Operating revenues from affiliates	749	779	1,423
Total operating revenues	19,135	17,393	15,630
Operating expenses			
Purchased power and fuel	10,007	9,368	6,927
Purchased power and fuel from affiliates	14	557	1,270
Operating and maintenance	4,688	4,943	3,960
Operating and maintenance from affiliates	620	623	574
Depreciation and amortization	1,054	967	856
Taxes other than income	489	465	389
Total operating expenses	16,872	16,923	13,976
Equity in (losses) earnings of unconsolidated affiliates		(20)	10
Gain on sales of assets	12	437	13
Gain on consolidation and acquisition of businesses		289	
Operating income	2,275	1,176	1,677
Other income and (deductions)			
Interest expense	(322)	(303)	(298)
Interest expense to affiliates, net	(43)	(53)	(59)
Other, net	(60)	406	355
Total other income and (deductions)	(425)	50	(2)
Income before income taxes	1,850	1,226	1,675
Income taxes	502	207	615
Equity in losses of unconsolidated affiliates	(8)		
Net income	1,340	1,019	1,060
Net income (loss) attributable to noncontrolling interests	(32)	184	(10)
Net income attributable to membership interest	$ 1,372	$ 835	$ 1,070
Comprehensive income, net of income taxes			
Net income	$ 1,340	$ 1,019	$ 1,060
Other comprehensive income (loss), net of income taxes			
Unrealized loss on cash flow hedges	(3)	(132)	(398)
Unrealized (loss) gain on equity investments	(3)	8	107
Unrealized loss on foreign currency translation	(21)	(9)	(10)

Unrealized (loss) gain on marketable securities		(1)	2
Reversal of CENG equity method AOCI		(116)	
Other comprehensive loss	(27)	(250)	(299)
Comprehensive income	$ 1,313	$ 769	$ 761

See the Combined Notes to Consolidated Financial Statements

207

Table of Contents

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2015	2014	2013
Cash flows from operating activities			
Net income	$ 1,340	$ 1,019	$ 1,060
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	2,589	2,519	2,559
Impairment of long-lived assets	12	663	157
Gain on consolidation and acquisition of businesses		(296)	
Gain on sales of assets	(12)	(437)	(13)
Deferred income taxes and amortization of investment tax credits	49	(198)	315
Net fair value changes related to derivatives	(249)	635	(448)
Net realized and unrealized losses (gains) on nuclear decommissioning trust fund investments	131	(210)	(170)
Other non-cash operating activities	268	346	270
Changes in assets and liabilities:			
Accounts receivable	194	(215)	109
Receivables from and payables to affiliates, net	15	15	2
Inventories	16	(359)	(88)
Accounts payable and accrued expenses	(149)	29	(160)
Option premiums received (paid), net	58	38	(36)
Collateral received (posted), net	407	(1,748)	162
Income taxes	(18)	265	402
Pension and non-pension postretirement benefit contributions	(245)	(297)	(149)
Other assets and liabilities	(207)	57	(85)
Net cash flows provided by operating activities	4,199	1,826	3,887
Cash flows from investing activities			
Capital expenditures	(3,841)	(3,012)	(2,752)
Proceeds from nuclear decommissioning trust fund sales	6,895	7,396	4,217
Investment in nuclear decommissioning trust funds	(7,147)	(7,551)	(4,450)
Cash and restricted cash acquired from consolidations and acquisitions		140	
Proceeds from sales of long-lived assets	147	1,719	32
Acquisitions of businesses	(40)	(386)	
Change in restricted cash	35	(87)	(64)
Changes in Exelon intercompany money pool		44	(44)
Distribution from CENG		13	115
Other investing activities	(118)	(43)	30
Net cash flows used in investing activities	(4,069)	(1,767)	(2,916)
Cash flows from financing activities			
Change in short-term borrowings		17	13
Issuance of long-term debt	1,309	1,112	854
Retirement of long-term debt	(89)	(586)	(570)
Retirement of long-term debt to affiliate	(550)		
Changes in Exelon intercompany money pool	1,252		
Distribution to member	(2,474)	(645)	(625)
Distribution to noncontrolling interest of consolidated VIE		(421)	
Contribution from member	47	53	26
Other financing activities	26	(67)	(82)
Net cash flows used in financing activities	(479)	(537)	(384)

Increase (decrease) in cash and cash equivalents	(349)	(478)	587
Cash and cash equivalents at beginning of period	780	1,258	671
Cash and cash equivalents at end of period	$ 431	$ 780	$ 1,258

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2015	2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 431	$ 780
Restricted cash and cash equivalents	123	158
Accounts receivable, net		
Customer	2,095	2,295
Other	360	318
Mark-to-market derivative assets	1,365	1,276
Receivables from affiliates	83	113
Unamortized energy contract assets	86	254
Inventories, net		
Fossil fuel	384	465
Materials and supplies	880	847
Assets held for sale	4	147
Other	531	658
Total current assets	6,342	7,311
Property, plant and equipment, net	25,843	23,028
Deferred debits and other assets		
Nuclear decommissioning trust funds	10,342	10,537
Investments	210	104
Goodwill	47	47
Mark-to-market derivative assets	733	771
Prepaid pension asset	1,689	1,704
Pledged assets for Zion Station decommissioning	206	319
Unamortized energy contract assets	484	549
Deferred income taxes	6	3
Other	627	578
Total deferred debits and other assets	14,344	14,612
Total assets [(a)]	$ 46,529	$ 44,951

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2015	2014
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 29	$ 36
Long-term debt due within one year	90	58
Long-term debt to affiliates due within one year		556
Accounts payable	1,583	1,759
Accrued expenses	935	886
Payables to affiliates	104	107
Borrowings from Exelon intercompany money pool	1,252	
Mark-to-market derivative liabilities	182	214
Unamortized energy contract liabilities	100	238
Renewable energy credit obligation	302	192
Other	356	413
Total current liabilities	4,933	4,459
Long-term debt	7,936	6,639
Long-term debt to affiliate	933	943
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,845	5,707
Asset retirement obligations	8,431	7,146
Non-pension postretirement benefit obligations	924	915
Spent nuclear fuel obligation	1,021	1,021
Payables to affiliates	2,577	2,880
Mark-to-market derivative liabilities	150	105
Unamortized energy contract liabilities	117	211
Payable for Zion Station decommissioning	90	155
Other	602	719
Total deferred credits and other liabilities	19,757	18,859
Total liabilities [(a)]	33,559	30,900
Commitments and contingencies		
Contingently redeemable noncontrolling interests	28	
Equity		
Member s equity		
Membership interest	8,997	8,951
Undistributed earnings	2,701	3,803
Accumulated other comprehensive income (loss), net	(63)	(36)
Total member s equity	11,635	12,718
Noncontrolling interest	1,307	1,333
Total equity	12,942	14,051

Total liabilities and equity	$ 46,529	$ 44,951

(a) Generation s consolidated assets include $8,235 million and $8,118 million at December 31, 2015 and 2014, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation s consolidated liabilities include $3,135 million and $2,512 million at December 31, 2015 and 2014, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 2 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Changes in Member s Equity

	Member s Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Equity
Balance, December 31, 2012	$ 8,876	$ 3,168	$ 513	$ 108	$ 12,665
Net income (loss)		1,070		(10)	1,060
Distribution to member		(625)			(625)
Allocation of tax benefit from member	26				26
Consolidated VIE dividend to noncontrolling interest				(63)	(63)
Deconsolidation of VIE	(1)			(18)	(19)
Noncontrolling interest acquired	(3)				(3)
Other comprehensive loss, net of income taxes			(299)		(299)
Balance, December 31, 2013	$ 8,898	$ 3,613	$ 214	$ 17	$ 12,742
Net income		835		184	1,019
Acquisition of noncontrolling interest				5	5
Allocation of tax benefit from member	53				53
Distribution to member		(645)			(645)
Noncontrolling interest established upon consolidation of CENG				1,548	1,548
Consolidated VIE dividend to noncontrolling interest				(421)	(421)
Reversal of CENG equity method AOCI, net of income taxes			(116)		(116)
Other comprehensive loss, net of income taxes			(134)		(134)
Balance, December 31, 2014	$ 8,951	$ 3,803	$ (36)	$ 1,333	$ 14,051
Net income (loss)		1,372		(32)	1,340
Acquisition of non-controlling interest	(1)			2	1
Adjustment of contingently redeemable noncontrolling interest due to release of contingency				4	4
Allocation of tax benefit from member	47				47
Distribution to member		(2,474)			(2,474)
Other comprehensive loss, net of income taxes			(27)		(27)
Balance, December 31, 2015	$ 8,997	$ 2,701	$ (63)	$ 1,307	$ 12,942

See the Combined Notes to Consolidated Financial Statements

211

Table of Contents

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Table of Contents

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(in millions)	For the Years Ended December 31, 2015	2014	2013
Operating revenues			
Electric operating revenues	$ 4,901	$ 4,560	$ 4,461
Operating revenues from affiliates	4	4	3
Total operating revenues	4,905	4,564	4,464
Operating expenses			
Purchased power	1,301	1,001	662
Purchased power from affiliate	18	176	512
Operating and maintenance	1,372	1,263	1,211
Operating and maintenance from affiliate	195	166	157
Depreciation and amortization	707	687	669
Taxes other than income	296	293	299
Total operating expenses	3,889	3,586	3,510
Gain on sales of assets	1	2	
Operating income	1,017	980	954
Other income and (deductions)			
Interest expense	(319)	(308)	(566)
Interest expense to affiliates, net	(13)	(13)	(13)
Other, net	21	17	26
Total other income and (deductions)	(311)	(304)	(553)
Income before income taxes	706	676	401
Income taxes	280	268	152
Net income	$ 426	$ 408	$ 249
Comprehensive income	$ 426	$ 408	$ 249

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	2015	For the Years Ended 2014	2013
Cash flows from operating activities			
Net income	$ 426	$ 408	$ 249
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	707	687	669
Deferred income taxes and amortization of investment tax credits	353	433	(57)
Other non-cash operating activities	416	255	28
Changes in assets and liabilities:			
Accounts receivable	(93)	(121)	(12)
Receivables from and payables to affiliates, net	(19)	(11)	(12)
Inventories	(40)	(16)	(18)
Accounts payable and accrued expenses	68	95	91
Counterparty collateral received (posted), net and cash deposits	(33)	2	53
Income taxes	192	(159)	178
Pension and non-pension postretirement benefit contributions	(150)	(248)	(122)
Other assets and liabilities	69	1	171
Net cash flows provided by operating activities	1,896	1,326	1,218
Cash flows from investing activities			
Capital expenditures	(2,398)	(1,689)	(1,433)
Proceeds from sales of investments		7	7
Purchases of investments		(3)	(4)
Change in restricted cash	2	(2)	(2)
Other investing activities	34	32	45
Net cash flows used in investing activities	(2,362)	(1,655)	(1,387)
Cash flows from financing activities			
Changes in short-term borrowings	(10)	120	184
Issuance of long-term debt	850	900	350
Retirement of long-term debt	(260)	(617)	(252)
Contributions from parent	202	273	
Dividends paid on common stock	(299)	(307)	(220)
Other financing activities	(16)	(10)	(1)
Net cash flows provided by financing activities	467	359	61
Increase (decrease) in cash and cash equivalents	1	30	(108)
Cash and cash equivalents at beginning of period	66	36	144
Cash and cash equivalents at end of period	$ 67	$ 66	$ 36

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheet

(In millions)	December 31, 2015	2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 67	$ 66
Restricted cash	2	4
Accounts receivable, net		
Customer	533	477
Other	272	648
Receivables from affiliates	199	14
Inventories, net	164	125
Regulatory assets	218	349
Other	63	40
Total current assets	1,518	1,723
Property, plant and equipment, net	17,502	15,793
Deferred debits and other assets		
Regulatory assets	895	852
Investments	6	6
Goodwill	2,625	2,625
Receivable from affiliates	2,172	2,571
Prepaid pension asset	1,490	1,551
Other	324	237
Total deferred debits and other assets	7,512	7,842
Total assets	$ 26,532	$ 25,358

See the Combined Notes to Consolidated Financial Statements

215

Table of Contents

Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2015	2014
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 294	$ 304
Long-term debt due within one year	665	260
Accounts payable	660	598
Accrued expenses	706	331
Payables to affiliates	62	84
Customer deposits	131	128
Regulatory liabilities	155	125
Mark-to-market derivative liability	23	20
Other	70	73
Total current liabilities	2,766	1,923
Long-term debt	5,844	5,665
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,914	4,561
Asset retirement obligations	111	103
Non-pension postretirement benefits obligations	259	263
Regulatory liabilities	3,459	3,655
Mark-to-market derivative liability	224	187
Other	507	889
Total deferred credits and other liabilities	9,474	9,658
Total liabilities	18,289	17,451
Commitments and contingencies		
Shareholders equity		
Common stock	1,588	1,588
Other paid-in capital	5,677	5,468
Retained earnings	978	851
Total shareholders equity	8,243	7,907
Total liabilities and shareholders equity	$ 26,532	$ 25,358

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Changes in Shareholders Equity

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders Equity
Balance, December 31, 2012	$ 1,588	$ 5,014	$ (1,639)	$ 2,360	$ 7,323
Net income			249		249
Common stock dividends				(220)	(220)
Parent tax matter indemnification		176			176
Appropriation of retained earnings for future dividends			(249)	249	
Balance, Balance at December 31, 2013	$ 1,588	$ 5,190	$ (1,639)	$ 2,389	$ 7,528
Net income			408		$ 408
Common stock dividends				(307)	(307)
Contribution from parent		273			273
Parent tax matter indemnification		5			5
Appropriation of retained earnings for future dividends			(408)	408	
Balance, December 31, 2014	$ 1,588	$ 5,468	$ (1,639)	$ 2,490	$ 7,907
Net income			426		426
Common stock dividends				(299)	(299)
Contribution from parent		202			202
Parent tax matter indemnification		7			7
Appropriation of retained earnings for future dividends			(426)	426	
Balance, December 31, 2015	$ 1,588	$ 5,677	$ (1,639)	$ 2,617	$ 8,243

See the Combined Notes to Consolidated Financial Statements

Table of Contents

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Table of Contents

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2015	2014	2013
Operating revenues			
Electric operating revenues	$ 2,485	$ 2,446	$ 2,499
Natural gas operating revenues	545	646	600
Operating revenues from affiliates	2	2	1
Total operating revenues	3,032	3,094	3,100
Operating expenses			
Purchased power	735	740	612
Purchased fuel	235	327	296
Purchased power from affiliate	220	194	392
Operating and maintenance	684	767	647
Operating and maintenance from affiliates	110	99	101
Depreciation and amortization	260	236	228
Taxes other than income	160	159	158
Total operating expenses	2,404	2,522	2,434
Gain on sales of assets	2		
Operating income	630	572	666
Other income and (deductions)			
Interest expense	(102)	(101)	(103)
Interest expense to affiliates, net	(12)	(12)	(12)
Other, net	5	7	6
Total other income and (deductions)	(109)	(106)	(109)
Income before income taxes	521	466	557
Income taxes	143	114	162
Net income	378	352	395
Preferred security dividends and redemption			7
Net income attributable to common shareholder	$ 378	$ 352	$ 388
Comprehensive income	$ 378	$ 352	$ 395

See the Combined Notes to Consolidated Financial Statements

219

Table of Contents

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2015	2014	2013
Cash flows from operating activities			
Net income	$ 378	$ 352	$ 395
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	260	236	228
Deferred income taxes and amortization of investment tax credits	90	88	20
Other non-cash operating activities	70	92	108
Changes in assets and liabilities:			
Accounts receivable	37	(16)	(79)
Receivables from and payables to affiliates, net	3	(6)	(18)
Inventories	10	2	2
Accounts payable and accrued expenses	(25)	58	31
Income taxes	(9)	(57)	87
Pension and non-pension postretirement benefit contributions	(40)	(16)	(31)
Other assets and liabilities	(4)	(21)	4
Net cash flows provided by operating activities	770	712	747
Cash flows from investing activities			
Capital expenditures	(601)	(661)	(537)
Change in restricted cash	(1)		(2)
Other investing activities	14	12	8
Net cash flows used in investing activities	(588)	(649)	(531)
Cash flows from financing activities			
Payment of accounts receivable agreement			(210)
Issuance of long-term debt	350	300	550
Retirement of long-term debt		(250)	(300)
Contributions from parent	16	24	27
Dividends paid on common stock	(279)	(320)	(332)
Dividends paid on preferred securities			(1)
Redemption of preferred securities			(93)
Other financing activities	(4)	(4)	(2)
Net cash flows provided by (used in) financing activities	83	(250)	(361)
Increase (decrease) in cash and cash equivalents	265	(187)	(145)
Cash and cash equivalents at beginning of period	30	217	362
Cash and cash equivalents at end of period	$ 295	$ 30	$ 217

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2015	2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 295	$ 30
Restricted cash and cash equivalents	3	2
Accounts receivable, net		
Customer	258	320
Other	146	141
Receivables from affiliates	2	3
Inventories, net		
Fossil fuel	43	57
Materials and supplies	26	22
Prepaid utility taxes	11	10
Regulatory assets	34	29
Other	24	31
Total current assets	842	645
Property, plant and equipment, net	7,141	6,801
Deferred debits and other assets		
Regulatory assets	1,583	1,529
Investments	28	31
Receivable from affiliates	405	490
Prepaid pension asset	347	344
Other	21	20
Total deferred debits and other assets	2,384	2,414
Total assets	$ 10,367	$ 9,860

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2015	2014
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Long-term debt due within one year	$ 300	$
Accounts payable	281	337
Accrued expenses	109	91
Payables to affiliates	55	52
Customer deposits	58	52
Regulatory liabilities	112	90
Other	29	31
Total current liabilities	944	653
Long-term debt	2,280	2,232
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,792	2,602
Asset retirement obligations	27	29
Non-pension postretirement benefits obligations	287	287
Regulatory liabilities	527	657
Other	90	95
Total deferred credits and other liabilities	3,723	3,670
Total liabilities	7,131	6,739
Commitments and contingencies		
Shareholder s equity		
Common stock	2,455	2,439
Retained earnings	780	681
Accumulated other comprehensive income, net	1	1
Total shareholder s equity	3,236	3,121
Total liabilities and shareholder s equity	$ 10,367	$ 9,860

See the Combined Notes to Consolidated Financial Statements

222

Table of Contents

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Changes in Shareholder s Equity

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholder s Equity
Balance, December 31, 2012	$ 2,388	$ 593	$ 1	$ 2,982
Net income		395		395
Common stock dividends		(332)		(332)
Preferred security dividends		(1)		(1)
Redemption of preferred dividends		(6)		(6)
Allocation of tax benefit from parent	27			27
Balance, December 31, 2013	$ 2,415	$ 649	$ 1	$ 3,065
Net income		352		352
Common stock dividends		(320)		(320)
Allocation of tax benefit from parent	24			24
Balance, December 31, 2014	$ 2,439	$ 681	$ 1	$ 3,121
Net income		378		378
Common stock dividends		(279)		(279)
Allocation of tax benefit from parent	16			16
Balance, December 31, 2015	$ 2,455	$ 780	$ 1	$ 3,236

See the Combined Notes to Consolidated Financial Statements

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Table of Contents

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2015	2014	2013
Operating revenues			
Electric operating revenues	$ 2,490	$ 2,460	$ 2,405
Natural gas operating revenues	631	680	647
Operating revenues from affiliates	14	25	13
Total operating revenues	3,135	3,165	3,065
Operating expenses			
Purchased power	602	733	676
Purchased fuel	205	302	293
Purchased power from affiliate	498	382	452
Operating and maintenance	565	614	551
Operating and maintenance from affiliates	118	103	83
Depreciation and amortization	366	371	348
Taxes other than income	224	221	213
Total operating expenses	2,578	2,726	2,616
Gain on sales of assets	1		
Operating income	558	439	449
Other income and (deductions)			
Interest expense	(83)	(90)	(106)
Interest expense to affiliates, net	(16)	(16)	(16)
Other, net	18	18	17
Total other income and (deductions)	(81)	(88)	(105)
Income before income taxes	477	351	344
Income taxes	189	140	134
Net income	288	211	210
Preference stock dividends	13	13	13
Net income attributable to common shareholder	$ 275	$ 198	$ 197
Comprehensive income	$ 288	$ 211	$ 210

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2015	2014	2013
Cash flows from operating activities			
Net income	$ 288	$ 211	$ 210
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	366	371	348
Deferred income taxes and amortization of investment tax credits	165	116	125
Other non-cash operating activities	137	180	153
Changes in assets and liabilities:			
Accounts receivable	84	46	(127)
Receivables from and payables to affiliates, net	(2)	(1)	(14)
Inventories	18	(6)	1
Accounts payable, accrued expenses	(3)	(75)	(6)
Collateral received (posted), net	(27)	27	
Income taxes	(54)	45	(33)
Pension and non-pension postretirement benefit contributions	(17)	(16)	(24)
Other assets and liabilities	(173)	(158)	(72)
Net cash flows provided by operating activities	782	740	561
Cash flows from investing activities			
Capital expenditures	(719)	(620)	(587)
Change in restricted cash	26	(22)	2
Other investing activities	18	20	14
Net cash flows used in investing activities	(675)	(622)	(571)
Cash flows from financing activities			
Changes in short-term borrowings	90	(15)	135
Issuance of long-term debt			300
Retirement of long-term debt	(75)	(70)	(467)
Dividends paid on common stock	(158)		
Dividends paid on preference stock	(13)	(13)	(13)
Allocations of tax benefit from parent	7		
Other financing activities	(13)	13	(3)
Net cash flows used in financing activities	(162)	(85)	(48)
Increase (decrease) in cash and cash equivalents	(55)	33	(58)
Cash and cash equivalents at beginning of period	64	31	89
Cash and cash equivalents at end of period	$ 9	$ 64	$ 31

See the Combined Notes to Consolidated Financial Statements

226

Table of Contents

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	**December 31, 2015**	**2014**
ASSETS		
Current assets		
Cash and cash equivalents	$ 9	$ 64
Restricted cash and cash equivalents	24	50
Accounts receivable, net		
Customer	300	390
Other	112	82
Inventories, net		
Gas held in storage	36	57
Materials and supplies	33	30
Prepaid utility taxes	61	59
Regulatory assets	267	214
Other	3	5
Total current assets	845	951
Property, plant and equipment, net	6,597	6,204
Deferred debits and other assets		
Regulatory assets	514	510
Investments	12	12
Prepaid pension asset	319	370
Other	8	9
Total deferred debits and other assets	853	901
Total assets [(a)]	$ 8,295	$ 8,056

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2015	December 31, 2014
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 210	$ 120
Long-term debt due within one year	378	75
Accounts payable	209	215
Accrued expenses	110	131
Payables to affiliates	52	66
Customer deposits	102	92
Regulatory liabilities	38	44
Other	35	51
Total current liabilities	1,134	794
Long-term debt	1,480	1,857
Long-term debt to financing trust	252	252
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,081	1,911
Asset retirement obligations	17	17
Non-pension postretirement benefits obligations	209	212
Regulatory liabilities	184	200
Other	61	60
Total deferred credits and other liabilities	2,552	2,400
Total liabilities [(a)]	5,418	5,303
Commitments and contingencies		
Shareholders equity		
Common stock	1,367	1,360
Retained earnings	1,320	1,203
Total shareholders equity	2,687	2,563
Preference stock not subject to mandatory redemption	190	190
Total equity	2,877	2,753
Total liabilities and shareholders equity	$ 8,295	$ 8,056

(a) BGE s consolidated assets include $26 million and $24 million at December 31, 2015 and December 31, 2014, respectively, of BGE s consolidated VIE that can only be used to settle the liabilities of the VIE. BGE s consolidated liabilities include $122 million and $197 million at December 31, 2015 and December 31, 2014, respectively, of BGE s consolidated VIE for which the VIE creditors do not have recourse to BGE. See Note 2 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statement of Changes in Shareholders Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholders Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2012	$ 1,360	$ 808	$ 2,168	$ 190	$ 2,358
Net income		210	210		210
Preference stock dividends		(13)	(13)		(13)
Balance, December 31, 2013	$ 1,360	$ 1,005	$ 2,365	$ 190	$ 2,555
Net income		211	211		211
Preference stock dividends		(13)	(13)		(13)
Balance, December 31, 2014	$ 1,360	$ 1,203	$ 2,563	$ 190	$ 2,753
Net income		288	288		288
Preference stock dividends		(13)	(13)		(13)
Common stock dividends		(158)	(158)		(158)
Contribution from parent	7		7		7
Balance, December 31, 2015	$ 1,367	$ 1,320	$ 2,687	$ 190	$ 2,877

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Combined Notes to Consolidated Financial Statements

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

Index to Combined Notes to Consolidated Financial Statements

The notes to the consolidated financial statements that follow are a combined presentation. The following list indicates the registrants to which the footnotes apply:

Applicable Notes

Registrant	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
Exelon Corporation																											
Exelon Generation Company, LLC																											
Commonwealth Edison Company																											
PECO Energy Company																											
Baltimore Gas And Electric Company																											

1. Significant Accounting Policies (Exelon, Generation, ComEd, PECO and BGE)

Description of Business (Exelon, Generation, ComEd, PECO and BGE)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy delivery businesses. On April 1, 2014, Generation assumed the operating licenses and corresponding operational control of CENG s nuclear fleet. As a result, Exelon and Generation consolidated CENG s financial position and results of operations into their businesses. Prior to April 1, 2014, Exelon and Generation accounted for CENG as an equity method investment. Refer to Note 5 Investment in Constellation Energy Nuclear Group, LLC for further information regarding the integration transaction.

The energy generation business includes:

Generation: Physical delivery and marketing of owned and contracted electric generation capacity and provision of renewable and other energy-related products and services, and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions.

The energy delivery businesses include:

ComEd: Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.

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

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

Basis of Presentation (Exelon, Generation, ComEd, PECO and BGE)

This is a combined annual report of Exelon, Generation, ComEd, PECO and BGE. The Notes to the Consolidated Financial Statements apply to Exelon, Generation, ComEd, PECO and BGE as

230

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

indicated above in the Index to Combined Notes to Consolidated Financial Statements and parenthetically next to each corresponding disclosure. When appropriate, Exelon, Generation, ComEd, PECO and BGE are named specifically for their related activities and disclosures.

Each of the Registrant s Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated. As a result of the Registrants 2014 divestiture of certain unconsolidated affiliates considered integral to their operations and the consolidation of CENG during 2014, all Equity in earnings (losses) from unconsolidated affiliates have been presented below Income taxes in the Registrants Consolidated Statements of Operations and Comprehensive Income starting in the first quarter of 2015.

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

Exelon owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for ComEd, of which Exelon owns more than 99%, and BGE, of which Exelon owns 100% of the common stock but none of BGE s preference stock. Exelon owned none of PECO s preferred securities, which PECO redeemed in 2013. Exelon has reflected the third-party interests in ComEd, which totaled less than $1 million at December 31, 2015 and December 31, 2014, as equity, PECO s preferred securities as preferred securities of subsidiary through their redemption in 2013, and BGE s preference stock as BGE preference stock not subject to mandatory redemption in its consolidated financial statements. BGE is subject to some ring-fencing measures established by order of the MDPSC. As part of this arrangement, BGE common stock is held directly by RF Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (BGE Utility), an unrelated party, holds a nominal non-economic interest in RF Holdco LLC with limited voting rights on specified matters.

Generation owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for certain Exelon Wind projects, of which Generation holds a majority interest of 99% for certain periods of time, and CENG, of which Generation holds a 50.01% interest. The remaining interests are included in noncontrolling interest on Exelon s and Generation s Consolidated Balance Sheets. See Note 2 Variable Interest Entities for further discussion of Exelon s and Generation s VIEs and the reversionary interests of the noncontrolling members for these certain subsidiaries.

ComEd owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for RITELine Illinois, LLC, of which ComEd owns 75% and an additional 12.5% is indirectly owned by Exelon. Exelon and ComEd have reflected the third-party interests of 12.5% and 25%, respectively, in RITELine Illinois, LLC, which both totaled less than $1 million at December 31, 2015 and December 31, 2014, as equity.

Exelon consolidates the accounts of entities in which Exelon has a controlling financial interest, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% in which Exelon can exercise control over the operations and

231

Combined Notes to Consolidated Financial Statements (Continued)

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

policies of the investee, or the results of a model that identifies Exelon or one of its subsidiaries as the primary beneficiary of a VIE. Where Exelon does not have a controlling financial interest in an entity, it applies proportionate consolidation, equity method accounting or cost method accounting. Exelon applies proportionate consolidation when it has an undivided interest in an asset and is proportionately liable for its share of each liability associated with the asset. Exelon proportionately consolidates its undivided ownership interests in jointly owned electric plants and transmission facilities, as well as its undivided ownership interests in Upstream natural gas exploration and production activities. Under proportionate consolidation, Exelon separately records its proportionate share of the assets, liabilities, revenues and expenses related to the undivided interest in the asset. Exelon applies equity method accounting when it has significant influence over an investee through an ownership in common stock, which generally approximates a 20% to 50% voting interest. Exelon applies equity method accounting to certain investments and joint ventures, including certain financing trusts of ComEd, PECO, and BGE. Under the equity method, Exelon reports its interest in the entity as an investment and Exelon s percentage share of the earnings from the entity as single line items in its financial statements. Exelon uses the cost method if it holds less than 20% of the common stock of an entity. Under the cost method, Exelon reports its investment at cost and recognizes income only to the extent Exelon receives dividends or distributions.

The accompanying consolidated financial statements have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC.

Use of Estimates (Exelon, Generation, ComEd, PECO and BGE)

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

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

Certain prior year amounts in the registrants Consolidated Statements of Operations and Comprehensive Income, Consolidated Balance Sheets and Consolidated Statements of Cash Flows have been reclassified between line items for comparative purposes. The reclassifications did not affect any of the Registrants net income, financial positions, or cash flows from operating activities.

Exelon revised the presentation on the Statements of Operations and Comprehensive Income for PECO and BGE to reflect separately operating revenues from the sale of electricity and operating revenues from the sale of natural gas, as well as, purchased power expense and purchased fuel expense within the operating expenses section of the Statement of Operations and Comprehensive Income. Further, Exelon revised the presentation from total operating revenues to Rate-regulated utility revenues and Competitive businesses revenues on the face of Exelon s consolidated Statement of Operations and Comprehensive Income for all periods presented. Similarly, Exelon will separately present rate-regulated purchased power and fuel expense and non-rate regulated

Combined Notes to Consolidated Financial Statements (Continued)

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

purchased power and fuel expense on the face of Exelon s consolidated Statement of Operations and Comprehensive Income for all periods presented. The reclassifications described herein were made for presentation purposes and did not affect any of the Registrants total revenues or net income.

Accounting for the Effects of Regulation (Exelon, ComEd, PECO and BGE)

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

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

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

Operating Revenues. Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers. ComEd records its best estimates of the distribution and transmission revenue impacts resulting from changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE records its best estimate of the transmission revenue impact resulting from changes in rates that BGE believes are probable of approval by FERC in accordance with its formula rate mechanism. See Note 3 Regulatory Matters and Note 6 Accounts Receivable for further information.

RTOs and ISOs. In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, the Registrants generally report sales and purchases conducted on a net hourly basis in either revenues or purchased power on their Consolidated Statements of Operations and Comprehensive Income, the classification of which depends on the net hourly activity. In addition, capacity revenue and expense classification is based on the net sale or purchase position of the Company in the different RTOs and ISOs.

233

Combined Notes to Consolidated Financial Statements (Continued)

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

Option Contracts, Swaps and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. For example, gas transactions may be used to hedge the sale of power. This will result in the change in fair value recorded through revenue. As ComEd receives full cost recovery for energy procurement and related costs from retail customers, ComEd records the fair value of its energy swap contracts with unaffiliated suppliers as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets. Refer to Note 3 Regulatory Matters and Note 13 Derivative Financial Instruments for further information.

Proprietary Trading Activities. Exelon and Generation account for Generation s trading activities under the provisions of the authoritative guidance for accounting for contracts involved in energy trading and risk management activities, which require energy revenues and costs related to energy trading contracts to be presented on a net basis in the income statement. Commodity derivatives used for trading purposes are accounted for using the mark-to-market method with unrealized gains and losses recognized in operating revenues. Refer to Note 13 Derivative Financial Instruments for further information.

Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

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

Pursuant to the IRC and relevant state taxing authorities, Exelon and its subsidiaries file consolidated or combined income tax returns for Federal and certain state jurisdictions where allowed or required. See Note 15 Income Taxes for further information.

Taxes Directly Imposed on Revenue-Producing Transactions (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer, but paid by the Registrants, while others are imposed on the Registrants. Where these taxes are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Consolidated Statements of Operations and Comprehensive Income. However, where these taxes are imposed on the Registrants, such as gross receipts taxes or other surcharges or fees, they are

Combined Notes to Consolidated Financial Statements (Continued)

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

reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 24 Supplemental Financial Information for Generation s, ComEd s, PECO s and BGE s utility taxes that are presented on a gross basis.

Cash and Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE)

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

Restricted Cash and Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE)

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2015 and 2014, Exelon Corporate s restricted cash and cash equivalents primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. Additionally, as of December 31, 2015 and 2014, Generation s restricted cash and cash equivalents primarily included cash at Antelope Valley required for debt service and construction and cash at Continental Wind and ExGen Texas Power, which is required for debt service and financing of operation and maintenance of the underlying entities. As of December 31, 2015 and 2014, ComEd s restricted cash primarily represented cash collateral held from suppliers associated with ComEd s energy and REC procurement contracts. As of December 31, 2015 and 2014, PECO s restricted cash primarily represented funds from the sales of assets that were subject to PECO s mortgage indenture. As of December 31, 2015 and 2014, BGE s restricted cash primarily represented funds restricted at its consolidated variable interest entity for repayment of rate stabilization bonds and cash collateral held from suppliers.

Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2015 and 2014, Exelon s and Generation s NDT funds, which are designated to satisfy future decommissioning obligations, were classified as noncurrent assets. As of December 31, 2015, Exelon, Generation, ComEd, PECO and BGE had investments in Rabbi trusts classified as noncurrent assets.

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

The allowance for uncollectible accounts reflects the Registrants best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging, historical experience and other currently available information. ComEd, PECO and BGE 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. 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 3 Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd.

Combined Notes to Consolidated Financial Statements (Continued)

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

Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Exelon accounts for its investments in and arrangements with VIEs based on the authoritative guidance which includes the following specific requirements:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,

- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events, and

- requires the entity that consolidates a VIE (the primary beneficiary) to disclose (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

Based on the above accounting guidance, Exelon has adopted the following policies related to variable interest entities:

- Exelon has disclosed, to the extent material, the assets of its consolidated VIEs that can only be used to settle specific obligations of the consolidated VIE, and the liabilities of Exelon s consolidated VIEs for which creditors do not have recourse to Exelon s general credit.

- Exelon has qualitatively assessed whether the equity holders of the entity have the power to direct matters that most significantly impact the entity.

See Note 2 Variable Interest Entities for additional information.

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

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

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

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

Emission Allowances. Emission allowances are included in inventory (for emission allowances exercisable in the current year) and other deferred debits (for emission allowances that are exercisable beyond one year) and are carried at the lower of weighted average cost or market and charged to fuel expense as they are used in operations.

Marketable Securities (Exelon, Generation, ComEd, PECO and BGE)

All marketable securities are reported at fair value. Marketable securities held in the NDT funds are classified as trading securities and all other securities are classified as available-for-sale securities.

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

Realized and unrealized gains and losses, net of tax, on Generation s NDT funds associated with the Regulatory Agreement Units are included in regulatory liabilities at Exelon, ComEd and PECO and in noncurrent payables to affiliates at Generation and in noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on Generation s NDT funds associated with the Non-Regulatory Agreement Units are included in earnings at Exelon and Generation. Unrealized gains and losses, net of tax, for Exelon s available-for-sale securities are reported in OCI. Any decline in the fair value of Exelon s available-for-sale securities below the cost basis is reviewed to determine if such decline is other-than-temporary. If the decline is determined to be other-than-temporary, the cost basis of the available-for-sale securities is written down to fair value as a new cost basis and the amount of the write-down is included in earnings. See Note 16 Asset Retirement Obligations for information regarding marketable securities held by NDT funds and Note 24 Supplemental Financial Information for additional information regarding ComEd s and PECO s regulatory assets and liabilities.

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

Property, plant and equipment is recorded at original cost. Original cost includes construction-related direct labor and material costs. ComEd, PECO and BGE also include indirect construction costs including labor and related costs of departments associated with supporting construction activities. When appropriate, original cost also includes capitalized interest for Generation and Exelon Corporate and AFUDC for regulated property at ComEd, PECO and BGE. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to maintenance expense as incurred.

Third parties reimburse ComEd, PECO and BGE for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, Plant and Equipment. DOE SGIG funds reimbursed to PECO and BGE have been accounted for as CIAC.

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

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

Generation s oil and gas exploration and production activities consist of working interests in gas producing fields. Generation accounts for these activities under the successful efforts method of accounting. Acquisition, development and exploration costs are capitalized. Costs of drilling exploratory wells are initially capitalized and later charged to expense if reserves are not discovered or deemed not to be commercially viable. Other exploratory costs are charged to expense when incurred.

Combined Notes to Consolidated Financial Statements (Continued)

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

See Note 7 Property, Plant and Equipment, Note 10 Jointly Owned Electric Utility Plant and Note 24 Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel (Exelon and Generation)

The cost of nuclear fuel is capitalized within property, plant and equipment and charged to fuel expense using the unit-of-production method. Prior to May 16, 2014, the estimated disposal cost of SNF was established per the Standard Waste Contract with the DOE and was expensed through fuel expense at one mill ($0.001) per kWh of net nuclear generation. Effective May 16, 2014, the SNF disposal fee was set to zero by the DOE and Exelon and Generation are not accruing any further costs related to SNF disposal fees until a new fee structure goes into effect. On-site SNF storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed. See Note 23 Commitments and Contingencies for additional information regarding the SNF disposal fee.

Nuclear Outage Costs (Exelon and Generation)

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to operating and maintenance expense or capitalized to property, plant and equipment (based on the nature of the activities) in the period incurred.

New Site Development Costs (Exelon and Generation)

New site development costs represent the costs incurred in the assessment and design of new power generating facilities. Such costs are capitalized when management considers project completion to be probable, primarily based on management s determination that the project is economically and operationally feasible, management and/or the Exelon board of directors has approved the project and has committed to a plan to develop it, and Exelon and Generation have received the required regulatory approvals or management believes the receipt of required regulatory approvals is probable. Capitalized development costs are charged to Operating and maintenance expense when project completion is no longer probable. New site development costs incurred prior to a project s completion being deemed probable are expensed as incurred. Approximately $22 million, $13 million and $10 million of costs were expensed by Exelon and Generation for the years ended December 31, 2015, 2014, and 2013, respectively. These costs are related to the possible development of new power generating facilities.

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

Capitalized Software Costs (Exelon, Generation, ComEd, PECO and BGE)

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

Net unamortized software costs	Exelon	Generation	ComEd	PECO	BGE
December 31, 2015	$ 633	$ 180	$ 172	$ 86	$ 178
December 31, 2014	596	193	133	84	163

Amortization of capitalized software costs	Exelon	Generation	ComEd	PECO	BGE
2015	$ 208	$ 73	$ 47	$ 33	$ 46
2014	186	59	45	28	43
2013	198	67	52	33	36

Depreciation, Depletion and Amortization (Exelon, Generation, ComEd, PECO and BGE)

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

See Note 7 Property, Plant and Equipment for further information regarding depreciation.

Depletion of oil and gas exploration and production activities is recorded using the units-of-production method over the remaining life of the estimated proved reserves at the field level for acquisition costs and over the remaining life of proved developed reserves at the field level for development costs. The estimates for oil and gas reserves are based on internal calculations.

Amortization of regulatory assets and liabilities are recorded over the recovery or refund period specified in the related legislation or regulatory agreement. When the recovery or refund period is less than one year, amortization is recorded to the line item in which the deferred cost or income would have originally been recorded in the Registrants Consolidated Statements of Operations and Comprehensive Income. Amortization of ComEd s distribution formula rate regulatory asset and ComEd s and BGE s transmission formula rate regulatory assets is recorded to Operating revenues.

Combined Notes to Consolidated Financial Statements (Continued)

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

Amortization of income tax related regulatory assets and liabilities is generally recorded to Income tax expense. With the exception of the regulatory assets and liabilities discussed above, when the recovery period is more than one year, the amortization is generally recorded to Depreciation and amortization in the Registrants Consolidated Statements of Operations and Comprehensive Income.

See Note 3 Regulatory Matters and Note 24 Supplemental Financial Information for additional information regarding Generation s nuclear fuel, Generation s ARC and the amortization of ComEd s, PECO s and BGE s regulatory assets.

Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

The authoritative guidance for accounting for AROs requires the recognition of a liability for a legal obligation to perform an asset retirement activity even though the timing and/or method of settlement may be conditional on a future event. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios. Decommissioning cost studies are updated, on a rotational basis, for each of Generation s nuclear units at least every five years unless circumstances warrant more frequent updates (such as a change in assumed operating life for a nuclear plant). As part of the annual cost study update process, Generation evaluates newly assumed costs or substantive changes in previously assumed costs to determine if the cost estimate impacts are sufficiently material to warrant application of the updated estimates to the AROs across the nuclear fleet outside of the normal five-year rotating cost study update cycle. The liabilities associated with Exelon s non-nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years. Changes to the recorded value of an ARO result from the passage of new laws and regulations, revisions to either the timing or amount of estimates of undiscounted cash flows, and estimates of cost escalation factors. AROs are accreted throughout each year to reflect the time value of money for these present value obligations through a charge to Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income or, in the case of the majority of ComEd s, PECO s, and BGE s accretion, through an increase to regulatory assets. See Note 16 Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC (Exelon, Generation, ComEd, PECO and BGE)

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

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

240

Combined Notes to Consolidated Financial Statements (Continued)

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

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

		Exelon [a]	Generation [a]	ComEd	PECO	BGE
2015	Total incurred interest [b]	$ 1,170	$ 445	$ 336	$ 116	$ 113
	Capitalized interest	79	79			
	Credits to AFUDC debt and equity	44		9	7	28
2014	Total incurred interest [b]	$ 1,144	$ 419	$ 323	$ 115	$ 118
	Capitalized interest	63	63			
	Credits to AFUDC debt and equity	37		5	8	24
2013	Total incurred interest [b]	$ 1,423	$ 411	$ 584	$ 117	$ 129
	Capitalized interest	54	54			
	Credits to AFUDC debt and equity	35		16	6	13

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 financial results include CENG s financial position and results of operations beginning April 1, 2014.
(b) Includes interest expense to affiliates.

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

The Registrants recognize, at the inception of a guarantee, a liability for the fair market value of the obligations they have undertaken by issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced as the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 23 Commitments and Contingencies for additional information.

Asset Impairments (Exelon, Generation, ComEd, PECO and BGE)

Long-Lived Assets. The Registrants evaluate the carrying value of their long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life. The Registrants determine if long-lived assets and asset groups are impaired by comparing the undiscounted expected future cash flows to the carrying value. 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 less costs to sell.

Cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The cash flows from the generating units are generally evaluated at a regional portfolio level along with cash flows generated from the customer supply and risk management activities, including cash flows from related intangible assets and liabilities on the balance sheet. In certain cases, generating assets

Combined Notes to Consolidated Financial Statements (Continued)

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

may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generation assets (typically contracted renewables). See Note 8 Impairment of Long-Lived Assets for additional information.

Goodwill. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is tested for impairment at least annually or on an interim basis if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 11 Intangible Assets for additional information regarding Exelon s, Generation s and ComEd s goodwill.

Equity Method Investments. Exelon and Generation regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature. Additionally, if the project in which Generation holds an investment recognizes an impairment loss, Exelon and Generation would record their proportionate share of that impairment loss and evaluate the investment for an other-than-temporary decline in value.

Debt and Equity Security Investments. Exelon and Generation regularly monitor and evaluate debt and equity investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature.

Direct Financing Lease Investments. Direct financing lease investments represent the estimated residual values of leased coal-fired plants in Georgia. Exelon reviews the estimated residual values of its direct financing lease investments and records an impairment charge if the review indicates an other-than-temporary decline in the fair value of the residual values below their carrying values. See Note 8 Impairment of Long-Lived Assets for additional information.

Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

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

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

For commodity derivative contracts 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 remained probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and was reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurred through March 31, 2015. The effect of this decision is that all derivatives executed to hedge economic risk related to commodities are recorded at fair value with changes in fair value recognized through earnings for the combined company.

As part of Generation s energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. Revenues and expenses on derivative contracts that qualify, and are designated, as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting. See Note 13 Derivative Financial Instruments for additional information.

Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees.

The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, including numerous assumptions and accounting elections. The assumptions are reviewed annually and at any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 17 Retirement Benefits for additional discussion of Exelon s accounting for retirement benefits.

Equity Investment Earnings (Losses) of Unconsolidated Affiliates (Exelon and Generation)

Exelon and Generation include equity in earnings from equity method investments in qualifying facilities, power projects and joint ventures, in equity in earnings (losses) of unconsolidated affiliates within their Consolidated Statements of Operations and Comprehensive Income. Equity in earnings (losses) of unconsolidated affiliates also includes any adjustments to amortize the difference, if any, except for goodwill and land, between their cost in an equity method investment and the underlying equity in net assets of the investee at the date of investment.

Exelon and Generation continuously monitor for issues that potentially could impact future profitability of these equity method investments and which could result in the recognition of an impairment loss if such investment experiences an other-than-temporary decline in value.

New Accounting Pronouncements (Exelon, Generation, ComEd, PECO and BGE)

Exelon has identified the following new accounting standards that have been recently adopted that management believes may significantly affect the Registrants.

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

Balance Sheet Classification of Deferred Taxes

In November 2015, the FASB issued authoritative guidance that requires deferred tax assets and deferred tax liabilities to be classified as noncurrent in a classified statement of financial position. The guidance is effective for periods beginning after December 15, 2016, with early adoption permitted. The guidance can be applied either prospectively or retrospectively. The Registrants early adopted the standard retrospectively in the fourth quarter of 2015, resulting in the following impacts as of December 31, 2014 in the Consolidated Balance Sheets of the Registrants:

For the year ended December 31, 2014 Increase (Decrease)	Exelon	Generation	ComEd	PECO	BGE
Current assets Deferred income taxes	$ (244)	$ (327)	$	$ (69)	$ (6)
Deferred debits and other assets Other	3				
Current liabilities Deferred income taxes			(63)		(52)
Deferred credits and other liabilities Deferred income taxes	(241)	(327)	63	(69)	46

The adoption of this guidance had no impact on the Registrants Consolidated Statements of Operations and Comprehensive Income and Consolidated Statements of Cash Flows.

Simplifying the Accounting for Measurement-Period Adjustments

In September 2015, the FASB issued authoritative guidance that requires an acquirer in a business combination to recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined and to record, in the same period s financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. Under current guidance, such effects would be retrospectively recorded in prior periods. The guidance is effective for periods beginning after December 15, 2015. The guidance is required to be applied prospectively to adjustments to provisional amounts that occur after the effective date with earlier application permitted for financial statements that have not been issued. The Registrants early adopted the standard in the fourth quarter of 2015. The adoption of this guidance had no impact on the Registrants Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures.

Application of Normal Purchases Normal Sales Exception to Power Contracts in Nodal Energy Markets

In August 2015, the FASB issued authoritative guidance addressing the ability of entities to elect the normal purchase normal sales (NPNS) scope exception when the contract for the purchase or sale of electricity on a forward basis is delivered to a nodal energy market or transmitted through a nodal energy market. The NPNS scope exception allows entities to treat certain contracts that qualify as derivatives as contracts that do not require recognition at fair value. The guidance specifies that the use of locational marginal pricing by an independent system operator in such transactions does not constitute net settlement of a contract for the purchase or sale of electricity, even in scenarios in which legal title to the associated electricity is conveyed to the independent system operator during transmission. Consequently, the use of locational marginal pricing by the independent system operator does not cause that contract to fail to meet the physical delivery criterion of the NPNS scope exception. Consistent with the Registrants current practice, if the physical delivery criterion is met, along with all of the other criteria of the NPNS scope exception, an entity may elect to designate that contract as

244

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

NPNS. The guidance is effective upon issuance and should be applied prospectively. The adoption of this guidance had no impact on the Registrants Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures.

Simplifying the Presentation of Debt Issuance Costs

In April 2015, the FASB issued authoritative guidance that changes the presentation of debt issuance costs in financial statements. The new guidance requires entities to present such costs in the balance sheet as a direct reduction to the related debt liability rather than as a deferred cost (i.e., an asset) as required by current guidance. The new guidance does not change the recognition or measurement of debt issuance costs. The guidance is effective for the Registrants for fiscal years beginning after December 15, 2015. Early adoption is permitted for financial statements that have not been previously issued. The guidance is required to be applied retrospectively to all prior periods presented. The Registrants early adopted the standard retrospectively in the fourth quarter of 2015. The adoption of this guidance resulted in a reclassification of $157 million, $70 million, $34 million, $14 million, and $16 million as of December 31, 2014, from Other long-term assets to Long-term debt, including Long-term debt to financing trusts, in the Consolidated Balance Sheets of Exelon, Generation, ComEd, PECO and BGE, respectively. The standard did not impact the Consolidated Statements of Operations and Comprehensive Income and Consolidated Statements of Cash Flows of the Registrants.

In August 2015, the FASB issued clarifying authoritative guidance for debt issuance costs incurred in connection with line-of-credit arrangements. The guidance states that an entity should defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement. The adoption of this guidance had no impact on the Registrants Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures.

The following recently issued accounting standards are not yet required to be reflected in the combined financial statements of the Registrants.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued authoritative guidance which (i) requires all investments in equity securities, including other ownership interests such as partnerships, unincorporated joint ventures and limited liability companies, to be carried at fair value through net income, (ii) requires an incremental recognition and disclosure requirement related to the presentation of fair value changes of financial liabilities for which the fair value option has been elected, (iii) amends several disclosure requirements, including the methods and significant assumptions used to estimate fair value or a description of the changes in the methods and assumptions used to estimate fair value, and (iv) requires disclosure of the fair value of financial assets and liabilities measured at amortized cost at the amount that would be received to sell the asset or paid to transfer the liability. The standard is effective for fiscal years beginning after December 15, 2017 with early adoption permitted. The guidance is required to be applied retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of adoption (modified retrospective method). The Registrants are currently assessing the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures as well as the potential to early adopt the guidance.

245

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

Simplifying the Measurement of Inventory

In July 2015, the FASB issued authoritative guidance that requires inventory to be measured at the lower of cost or net realizable value. The new guidance defines net realizable value as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This definition is consistent with existing authoritative guidance. Current guidance requires inventory to be measured at the lower of cost or market where market could be replacement cost, net realizable value or net realizable value less an approximately normal profit margin. The guidance is effective for periods beginning after December 15, 2016 with early adoption permitted. The guidance is required to be applied prospectively. The Registrants do not expect that this guidance will have a significant impact on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. The Registrants are currently assessing the potential to early adopt the guidance.

Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share

In May 2015, FASB issued authoritative guidance that removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. Investments measured at net asset value per share using the practical expedient will be presented as a reconciling item between the fair value hierarchy disclosure and the investment line item on the statement of financial position. The guidance also removes the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient. Rather, those disclosures are limited to investments for which the entity has elected to measure the fair value using the practical expedient. The guidance is effective for the Registrants for fiscal years beginning after December 15, 2015 with early adoption permitted. The guidance is required to be applied retrospectively to all prior periods presented. The Registrants are currently assessing the impacts this guidance may have on their disclosures. There will be no impact to the Registrants Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income and Consolidated Statements of Cash Flows.

Customer s Accounting for Fees Paid in a Cloud Computing Arrangement

In April 2015, the FASB issued authoritative guidance that clarifies the circumstances under which a cloud computing customer would account for the arrangement as a license of internal-use software. A cloud computing arrangement would include a software license if (1) the customer has a contractual right to take possession of the software at any time during the hosting period without significant penalty and (2) it is feasible for the customer to either run the software on its own hardware or contract with another party unrelated to the vendor to host the software. If the arrangement does not contain a software license, it would be accounted for as a service contract. Beginning January 1, 2016, the Registrants will apply the standard prospectively and do not expect that this guidance will have a significant impact on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures.

Amendments to the Consolidation Analysis

In February 2015, the FASB issued authoritative guidance that amends the consolidation analysis for variable interest entities (VIEs) as well as voting interest entities. The new guidance primarily (1) changes the assessment of limited partnerships as VIEs, (2) amends the effect that fees paid to a decision maker or service provider have on the VIE analysis, (3) amends how variable interests held by

Combined Notes to Consolidated Financial Statements (Continued)

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

a reporting entity s related parties and de facto agents impact its consolidation conclusion, (4) clarifies how to determine whether equity holders (as a group) have power over an entity, and (5) provides a scope exception for registered and similar unregistered money market funds. The guidance is effective for the Registrants for the first interim period beginning on or after December 15, 2015. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of adoption (modified retrospective method). The Registrants are in the process of evaluating the standard and have not identified any changes to consolidation conclusions as a result of the new guidance and therefore have not elected an adoption method. Based on the analysis completed to date, a limited number of additional entities will be considered variable interest entities when the guidance is adopted, and required disclosures will be included in the Variable Interest Entities footnote.

Revenue from Contracts with Customers

In May 2014, the FASB issued authoritative guidance that changes the criteria for recognizing revenue from a contract with a customer. The new standard replaces existing guidance on revenue recognition, including most industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing and uncertainty of revenue and the related cash flows. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Registrants are currently assessing the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures as well as the transition method that they will use to adopt the guidance. Exelon is considering the impacts of the new guidance on our ability to recognize revenue for certain contracts where collectability is in question, our accounting for contributions in aid of construction, bundled sales contracts and contracts with pricing provisions that may require us to recognize revenue at prices other than the contract price (e.g., straight line or forward curve). In addition, the Registrants will be required to capitalize costs to acquire new contracts, whereas Exelon currently expenses those costs as incurred. In August 2015, the FASB issued an amendment to provide a one year deferral of the effective date to annual reporting periods beginning on or after December 15, 2017, as well as an option to early adopt the standard for annual periods beginning on or after December 15, 2016. The Registrants do not plan to early adopt the standard.

2. Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

A VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly affect the entity s economic performance.

Combined Notes to Consolidated Financial Statements (Continued)

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

At December 31, 2015 and 2014, Exelon, Generation, and BGE collectively consolidated seven and six VIEs or VIE groups, respectively, for which the applicable Registrant was the primary beneficiary (*see Consolidated Variable Interest Entities below)*. As of December 31, 2015 and 2014, the Registrants had significant interests in eight and six other VIEs, respectively, for which the Registrants do not have the power to direct the entities activities and, accordingly, were not the primary beneficiary (*see Unconsolidated Variable Interest Entities below)*.

Consolidated Variable Interest Entities

The carrying amounts and classification of the consolidated VIEs assets and liabilities included in the Registrants consolidated financial statements at December 31, 2015 and 2014 are as follows:

	December 31, 2015			December 31, 2014 [a]		
	Exelon [b]	Generation	BGE	Exelon [b]	Generation	BGE
Current assets	$ 909	$ 881	$ 23	$ 1,275	$ 1,247	$ 21
Noncurrent assets	8,009	8,004	3	7,573	7,560	3
Total assets	$ 8,918	$ 8,885	$ 26	$ 8,848	$ 8,807	$ 24
Current liabilities	$ 473	$ 387	$ 81	$ 611	$ 526	$ 77
Noncurrent liabilities	2,927	2,884	41	2,728	2,597	120
Total liabilities	$ 3,400	$ 3,271	$ 122	$ 3,339	$ 3,123	$ 197

(a) Certain December 31, 2014 balances have been adjusted for the adoption of accounting guidance related to classification of deferred taxes and simplifying the presentation of debt costs. See Note 1 Significant Accounting Policies for additional information.
(b) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.

Except as specifically noted below, the assets in the table above are restricted for settlement of the VIE obligations and the liabilities in the table can only be settled using VIE resources.

Exelon s, Generation s and BGE s consolidated VIEs consist of:

RSB BondCo LLC. In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1. BGE has determined that BondCo is a VIE for which it is the primary beneficiary. As a result, BGE consolidates BondCo.

BondCo s assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During 2015, 2014, and 2013, BGE remitted $86 million, $85 million, and $83 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2015. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

Retail Gas Group. During 2009, Constellation formed two new entities, which now are part of Generation, and combined them with its existing retail gas activities into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement with a third-party gas supplier. While Generation owns 100% of these entities, it has been determined that the retail gas entity group is a VIE because there is not sufficient equity to fund the group s activities without the additional credit support that is provided in the form of a parental guarantee. Generation is the primary beneficiary of the retail gas entity group; accordingly, Generation consolidates the retail gas entity group as a VIE.

The third-party gas supply arrangement is collateralized as follows:

- the assets of the retail gas entity group must be used to settle obligations under the third-party gas supply agreement before it can make any distributions to Generation,
- the third-party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and
- Generation provides a $75 million parental guarantee to the third-party gas supplier in support of the retail gas entity group.

Other than credit support provided by the parental guarantee, Exelon or Generation do not have any contractual or other obligations to provide additional financial support under the collateralized third-party gas supply agreement. The third-party gas supply creditors do not have any recourse to Exelon s or Generation s general credit other than the parental guarantee.

Solar Project Entity Group. In 2011, Generation acquired all of the equity interests in Antelope Valley Solar Ranch One (Antelope Valley) from First Solar, Inc., a 242-MW solar PV project in northern Los Angeles County, California. In addition, Generation owns a number of limited liability companies that build, own, and operate solar power facilities. While Generation owns 100% of these entities, it has been determined that certain of the individual solar project entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the solar project entities that qualify as VIEs because Generation controls the design, construction, and operation of the solar power facilities. Generation provides operating and capital funding to the solar entities for ongoing construction, operations and maintenance of the solar power facilities and provides limited recourse related to the Antelope Valley project. In addition, these solar VIE entities have an aggregate amount of outstanding debt with third parties of $655 million, as of December 31, 2015, for which the creditors have no recourse to Generation. For additional information on these project-specific financing arrangements refer to Note 14 Debt and Credit Agreements.

Retail Power and Gas Companies. In March 2014, Generation began consolidating retail power and gas VIEs for which Generation is the primary beneficiary as a result of energy supply contracts that give Generation the power to direct the activities that most significantly affect the economic performance of the entities. Generation does not have an equity ownership interest in these entities, but provides approximately $12 million in credit support for the retail power and gas companies. These entities are included in Generation s consolidated financial statements, and the consolidation of the VIEs do not have a material impact on Generation s financial results or financial condition.

Wind Project Entity Group. Generation owns and operates a number of wind project limited liability entities, the majority of which were acquired during 2010 with the acquisition of all of the equity

Combined Notes to Consolidated Financial Statements (Continued)

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

interests of John Deere Renewables, LLC (now known as Exelon Wind). Generation has evaluated the significant agreements and ownership structures and the risks of each of its wind projects and underlying entities, and determined that certain of the entities are VIEs because either the projects have noncontrolling equity interest holders that absorb variability from the wind projects, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the wind project entities that qualify as VIEs because Generation controls the design, construction, and operation of the wind generation facilities. While Generation owns 100% of the majority of the wind project entities, nine of the projects have noncontrolling equity interests of 1% held by third parties. Generation s current economic interests in eight of these projects is significantly greater than its stated contractual governance rights and all of these projects have reversionary interest provisions that provide the noncontrolling interest holder with a purchase option, certain of which are considered bargain purchase prices, which, if exercised, transfers ownership of the projects to the noncontrolling interest holder upon either the passage of time or the achievement of targeted financial returns. The ownership agreements with the noncontrolling interests state that Generation is to provide financial support to the projects in proportion to its current 99% economic interests in the projects. However, no additional support to these projects beyond what was contractually required has been provided during 2015. As of December 31, 2015, the carrying amount of the assets and liabilities that are consolidated as a result of Generation being the primary beneficiary of the wind VIE entities primarily relates to the wind generating assets, PPA intangible assets and working capital amounts.

Other Generating Facilities. During the second quarter of 2015, Generation formed a limited liability company to build, own, and operate a backup generator. While Generation owns 100% of the backup generator company, it was determined that the entity is a VIE because the customer absorbs price variability from the entity through the fixed price backup generator agreement. Generation provides operating and capital funding to the backup generator company. Generation also owns 90% of a biomass fueled, combined heat and power company. In the second quarter of 2015, the entity was deemed to be a VIE because the entity requires additional subordinated financial support in the form of a parental guarantee provided by Generation for up to $275 million in support of the payment obligations related to the Engineering, Procurement and Construction contract for the facility (see Note 14 Debt and Credit Agreements for additional details on Albany Green Energy, LLC). In addition to the parental guarantee, Generation provides operating and capital funding to the biomass fueled, combined heat and power company. Generation is the primary beneficiary of both entities since Generation has the power to direct the activities that most significantly affect the economic performance of the entities.

CENG. Through March 31, 2014, CENG was operated as a joint venture with EDF and was governed by a board of ten directors, five of which were appointed by Generation and five by EDF. CENG was designed to operate under joint and equal control of Generation and EDF through the Board of Directors, subject to the Chairman of the Board s final decision making authority on certain special matters; therefore, CENG was not subject to VIE guidance. Accordingly, Generation s 50.01% interest in CENG was accounted for as an equity method investment. On April 1, 2014, Generation, CENG, and subsidiaries of CENG executed the Nuclear Operating Services Agreement (NOSA) pursuant to which Generation now conducts all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF. As a result of executing the NOSA, CENG now qualifies as a VIE due to the disproportionate relationship between Generation s 50.01% equity ownership interest and its role in conducting the operational activities of CENG and the CENG fleet conveyed through the NOSA.

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

Further, since Generation is conducting the operational activities of CENG and the CENG fleet, Generation qualifies as the primary beneficiary of CENG and, therefore, is required to consolidate the financial position and results of operations of CENG. On April 1, 2014, Exelon and Generation derecognized Generation s equity method investment in CENG and reflected all assets, liabilities, and the EDF noncontrolling interest in CENG at fair value on the consolidated balance sheets of Exelon and Generation, resulting in the recognition of a $261 million gain in their respective Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2014. For additional information on this transaction refer to Note 5 Investment in Constellation Energy Nuclear Group, LLC.

Generation and Exelon, where indicated, provide the following support to CENG (See Note 5 Investment in Constellation Energy Nuclear Group, LLC and Note 26 Related Party Transactions for additional information regarding Generation and Exelon s transactions with CENG):

under the NOSA, Generation conducts all activities related to the operation of the CENG nuclear generation fleet owned by CENG subsidiaries (the CENG fleet) and provides corporate and administrative services for the remaining life and decommissioning of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF,

under the Power Services Agency Agreement (PSAA), Generation provides scheduling, asset management, and billing services to the CENG fleet for the remaining operating life of the CENG nuclear plants,

under power purchase agreements with CENG, Generation purchased or will purchase 50.01% of the available output generated by the CENG nuclear plants not subject to other contractual agreements from January 2015 through the end of the operating life of each respective plant. However, pursuant to amendments dated March 31, 2015, the energy obligations under the Ginna Nuclear Power Plant (Ginna) PPAs have been suspended during the term of the expected Reliability Support Services Agreement (RSSA). (see Note 3 Regulatory Matters for additional details),

Generation provided a $400 million loan to CENG. As of December 31, 2015, the remaining obligation is $300 million including accrued interest, which reflects the principal payment made in January 2015 (see Note 5 Investment in Constellation Energy Nuclear Group, LLC for more details),

Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation s obligations under this Indemnity Agreement. (See Note 23 Commitments and Contingencies for more details),

in connection with CENG s severance obligations, Generation has agreed to reimburse CENG for a total of approximately $6 million of the severance benefits paid or to be paid in 2014 through 2016. As of December 31, 2015, the remaining obligation is approximately $1 million,

Generation and EDF share in the $637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance (See Note 23 Commitments and Contingencies for more details), Generation provides a guarantee of approximately $7 million associated with hazardous waste management facilities and underground storage tanks. In addition, EDF executed a reimbursement agreement that provides reimbursement to Exelon for 49.99% of any amounts paid by Generation under this guarantee,

Combined Notes to Consolidated Financial Statements (Continued)

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

- Generation and EDF are the members-insured with Nuclear Electric Insurance Limited and have assigned the loss benefits under the insurance and the NEIL premium costs to CENG and guarantee the obligations of CENG under these insurance programs in proportion to their respective member interests (see Note 23 Commitments and Contingencies for more details), and

- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG s cash pooling agreement with its subsidiaries.

For each of the consolidated VIEs, except as otherwise noted:

- the assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;

- Exelon, Generation and BGE did not provide any additional material financial support to the VIEs;

- Exelon, Generation and BGE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and

- the creditors of the VIEs did not have recourse to Exelon s, Generation s or BGE s general credit.

As of December 31, 2015 and 2014, ComEd and PECO did not have any material consolidated VIEs.

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

Assets and Liabilities of Consolidated VIEs

Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors, or beneficiaries, do not have recourse to the general credit of the Registrants. As of December 31, 2015 and 2014, these assets and liabilities primarily consisted of the following:

	December 31, 2015			December 31, 2014 [(a)]		
	Exelon	Generation	BGE	Exelon	Generation	BGE
Cash and cash equivalents	$ 164	$ 164	$	$ 392	$ 392	$
Restricted cash	100	77	23	117	96	21
Accounts receivable, net						
Customer	219	219		297	297	
Other	43	43		57	57	
Mark-to-market derivatives assets	140	140		171	171	
Inventory						
Materials and supplies	181	181		172	172	
Other current assets	35	30		37	30	
Total current assets	882	854	23	1,243	1,215	21
Property, plant and equipment, net	5,160	5,160		4,638	4,638	
Nuclear decommissioning trust funds	2,036	2,036		2,097	2,097	
Goodwill	47	47		47	47	
Mark-to-market derivatives assets	53	53		44	44	
Other noncurrent assets	90	85	3	90	77	3
Total noncurrent assets	7,386	7,381	3	6,916	6,903	3
Total assets	$ 8,268	$ 8,235	$ 26	$ 8,159	$ 8,118	$ 24
Long-term debt due within one year	$ 111	$ 27	$ 79	$ 87	$ 5	$ 75
Accounts payable	216	216		292	292	
Accrued expenses	115	113	2	111	108	2
Mark-to-market derivative liabilities	5	5		24	24	
Unamortized energy contract liabilities	12	12		22	22	
Other current liabilities	13	13		25	25	
Total current liabilities	472	386	81	561	476	77
Long-term debt	666	623	41	212	81	120
Asset retirement obligations	1,999	1,999		1,763	1,763	
Pension obligation [(b)]	9	9		9	9	
Unamortized energy contract liabilities	39	39		51	51	
Other noncurrent liabilities	79	79		132	132	

Noncurrent liabilities	2,792	2,749	41	2,167	2,036	120
Total liabilities	$ 3,264	$ 3,135	$ 122	$ 2,728	$ 2,512	$ 197

(a) Certain December 31, 2014 balances have been adjusted for the adoption of accounting guidance related to classification of deferred taxes and simplifying the presentation of debt costs. See Note 1- Significant Accounting Policies for additional information.

(b) Includes the CNEG retail gas pension obligation, which is presented as a net asset balance within the Prepaid pension asset line item on Generation s balance sheet. See Note 17 Retirement Benefits for additional details.

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

Unconsolidated Variable Interest Entities

Exelon s and Generation s variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected on Exelon s and Generation s Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in Exelon s and Generation s Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

As of December 31, 2015 and 2014, Exelon and Generation had significant unconsolidated variable interests in eight and six VIEs, respectively, for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity method investments and certain commercial agreements. The increase in the number of unconsolidated VIEs is due to the execution of an energy purchase and sale agreement with a new unconsolidated VIE and an equity investment in a new unconsolidated VIE.

The following tables present summary information about Exelon and Generation s significant unconsolidated VIE entities:

December 31, 2015	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 263	$ 164	$ 427
Total liabilities [a]	22	125	147
Exelon s ownership interest in VIE [a]		11	11
Other ownership interests in VIE [a]	241	28	269
Registrants maximum exposure to loss:			
Carrying amount of equity method investments		21	21
Contract intangible asset	9		9
Debt and payment guarantees		3	3
Net assets pledged for Zion Station decommissioning [b]	17		17

December 31, 2014	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 114	$ 91	$ 205
Total liabilities [a]	3	49	52
Exelon s ownership interest in VIE [a]		9	9
Other ownership interests in VIE [a]	111	33	144
Registrants maximum exposure to loss:			
Carrying amount of equity method investments		13	13
Contract intangible asset	9		9

Debt and payment guarantees	3	3
Net assets pledged for Zion Station decommissioning [(b)]	27	27

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon s or Generation s Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs. Exelon corrected an error in the December 31, 2014 balances within Commercial Agreement VIEs for an overstatement of Total assets, Total liabilities and Other ownership interests in VIE of $392 million, $234 million and $158 million, respectively. The error is not considered material to any prior period.

Combined Notes to Consolidated Financial Statements (Continued)

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

(b) These items represent amounts on Exelon s and Generation s Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $206 million and $319 million as of December 31, 2015 and December 31, 2014, respectively; offset by payables to ZionSolutions LLC of $189 million and $292 million as of December 31, 2015 and December 31, 2014, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

For each unconsolidated VIE, Exelon and Generation assessed the risk of a loss equal to their maximum exposure to be remote and, accordingly Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would materially affect the fair value or risk of their variable interests in these variable interest entities.

Energy Purchase and Sale Agreements. Generation has several energy purchase and sale agreements with generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each entity, and determined that certain of the entities are VIEs because the entity absorbs risk through the sale of fixed price power and renewable energy credits. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the VIEs because Generation does not have the power to direct the activities that most significantly impact the VIEs economic performance.

ZionSolutions. Generation has an asset sale agreement with EnergySolutions, Inc. and certain of its subsidiaries, including ZionSolutions, LLC (ZionSolutions), which is further discussed in Note 16 Asset Retirement Obligations. Under this agreement, ZionSolutions can put the assets and liabilities back to Generation when decommissioning activities under the asset sale agreement are complete. Generation has evaluated this agreement and determined that, through the put option, it has a variable interest in ZionSolutions but is not the primary beneficiary. As a result, Generation has concluded that consolidation is not required. Other than the asset sale agreement, Exelon and Generation do not have any contractual or other obligations to provide additional financial support and ZionSolutions creditors do not have any recourse to Exelon s or Generation s general credit.

Investment in Energy Development Projects, Distributed Energy Companies, and Energy Generating Facilities. Generation has several equity investments in energy development projects and energy generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each of its equity investments, and determined that certain of the entities are VIEs because the entity has an insufficient amount of equity at risk to finance its activities, Generation guarantees the debt of the entity, provides equity support, or provides operating services to the entity. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the entities that qualify as VIEs because Generation does not have the power to direct the activities that most significantly impact the VIEs economic performance.

In July 2014, Generation entered into an arrangement to purchase a 90% equity interest and 90% of the tax attributes of a distributed energy company. Generation s total equity commitment in this arrangement was $91 million and is paid incrementally over an approximate two year period (see Note 23 Commitments and Contingencies for additional details). This arrangement did not meet the definition of a VIE and is recorded as an equity method investment.

In June 2015, 2015 ESA Investco, LLC, then a wholly owned subsidiary of Generation, entered into an arrangement to purchase a 90% equity interest and 99% of the tax attributes of another distributed energy company. Separate from the equity investment, Generation provided $27 million in cash to the other (10%) equity holder in the distributed energy company in exchange for a convertible

Combined Notes to Consolidated Financial Statements (Continued)

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

promissory note. In November 2015, Generation sold 69% of its equity interest in 2015 ESA Investco, LLC to a tax equity investor. Generation and the tax equity investor will contribute $250 million of equity incrementally through December 2016 in proportion to their ownership interests, which equates to approximately $172 million for the tax equity investor and $78 million for Generation (see Note 23 Commitments and Contingencies for additional details). Generation and the tax equity investor provide a parental guarantee of up to $275 million in proportion to their ownership interests in support of 2015 ESA Investco, LLC s obligation to make equity contributions to the distributed energy company. The investment in the distributed energy company was evaluated and it was determined to be a VIE for which Generation is not the primary beneficiary. Generation continues to consolidate 2015 ESA Investco, LLC under the voting interest model.

Both distributed energy companies from the 2014 and 2015 arrangements are considered related parties.

ComEd, PECO and BGE

The financing trust of ComEd, ComEd Financing III, the financing trusts of PECO, PECO Trust III and PECO Trust IV, and the financing trust of BGE, BGE Capital Trust II are not consolidated in Exelon s, ComEd s, PECO s or BGE s financial statements. These financing trusts were created to issue mandatorily redeemable trust preferred securities. ComEd, PECO, and BGE have concluded that they do not have a significant variable interest in ComEd Financing III, PECO Trust III, PECO Trust IV or BGE Capital Trust II as each Registrant financed its equity interest in the financing trusts through the issuance of subordinated debt and, therefore, has no equity at risk. See Note 14 Debt and Credit Agreements for additional information.

3. Regulatory Matters (Exelon, Generation, ComEd, PECO and BGE)

The following matters below discuss the current status of material regulatory and legislative proceedings of the Registrants.

Illinois Regulatory Matters

Energy Infrastructure Modernization Act (Exelon and ComEd).

Background

Since 2011, ComEd s electric distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities to modernize Illinois electric utility infrastructure. EIMA was 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. On April 3, 2015, the Governor signed legislation extending the EIMA sunset from 2017 to 2019.

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 (initial revenue requirement). The update also reconciles any differences between the revenue requirement in effect for the prior year and actual costs incurred for that year (annual reconciliation). See *Annual Electric Distribution Filings* below for further details. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to

Combined Notes to Consolidated Financial Statements (Continued)

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

Operating revenue for any differences between the revenue requirement in effect and ComEd s best estimate of the revenue requirement expected to be approved by the ICC for that year s reconciliation. As of December 31, 2015, and December 31, 2014, ComEd had a regulatory asset associated with the electric distribution formula rate of $189 million and $371 million, respectively. The regulatory asset associated with electric distribution true-up is amortized to Operating revenue in ComEd s Consolidated Statement of Operations and Comprehensive Income as the associated amounts are recovered through rates.

Participating utilities are also required to file an annual update on their AMI implementation progress. On April 1, 2015, ComEd filed an annual progress report on its AMI Implementation Plan with the ICC, which allows for the installation of more than four million smart meters throughout ComEd s service territory by 2018. To date, approximately two million smart meters have been installed in the Chicago area.

Pursuant to EIMA, ComEd annually contributes $4 million for customer education for as long as the AMI Deployment Plan remains in effect. Additionally, ComEd contributes $10 million annually through 2016 to fund customer assistance programs for low-income customers, which will not be recoverable through rates.

Annual Electric Distribution Filings

For each of the following years, the ICC approved the following total increases/(decreases) in ComEd s electric distributions formula rate filings:

Annual Distribution Filings	**2015**	**2014**	**2013**
ComEd s requested total revenue requirement (decrease) increase	$ (50)	$ 269	$ 353
Final ICC Order			
Initial revenue requirement increase	$ 85	$ 160	$ 160
Annual reconciliation (decrease) increase	(152)	72	181
Total revenue requirement (decrease) increase	$ (67)	$ 232	$ 341
Allowed Return on Rate Base:			
Initial revenue requirement	7.05%	7.06%	6.94%
Annual reconciliation	7.02%	7.04%	6.94%
Allowed ROE:			
Initial revenue requirement	9.14%[(a)]	9.25%[(a)]	8.72%
Annual reconciliation	9.09%[(a)]	9.20%[(a)]	8.72%
Effective date of rates	January 2016	January 2015	January 2014

(a) Includes a reduction of 5 basis points for a reliability performance metric penalty.

Formula Rate Structure Investigation

In October 2013, the ICC opened an investigation (the Investigation), in response to a complaint filed by the Illinois Attorney General, to change the formula rate structure by requesting three changes: the elimination of the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance, the netting of associated accumulated deferred income

Combined Notes to Consolidated Financial Statements (Continued)

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

taxes against the annual reconciliation balance in calculating interest, and the use of average rather than year-end rate base for determining any ROE collar adjustment. On November 26, 2013, the ICC issued its final order in the Investigation, rejecting two of the proposed changes but accepting the proposed change to eliminate the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance. The accepted change became effective in January 2014, and reduced ComEd s 2014 revenue by approximately $8 million. This change had no financial statement impact on ComEd in 2013. ComEd and intervenors requested rehearing, however all rehearing requests were denied by the ICC. ComEd and intervenors filed appeals with the Illinois Appellate Court. ComEd subsequently withdrew its appeal, but the Illinois Attorney General and the Citizens Utility Board continued to argue that the ICC had wrongly approved ComEd s treatment of accumulated deferred income taxes (ADIT) relating to the annual reconciliation. On July 29, 2015, the Illinois Appellate Court rejected that appeal and affirmed the ICC s decision and its acceptance of ComEd s treatment of ADIT. The period in which to file requests for further review has expired and that decision is final.

Appeal of Initial Formula Rate Tariff

On March 26, 2014, the Illinois Appellate Court issued an opinion with respect to ComEd s appeal of the ICC s order relating to ComEd s initial formula rate tariff. The most significant financial issues under appeal related to ICC findings that were counter to the formula rate legislation and were clarified by subsequent legislation (Senate Bill 9). Therefore, only a subset of the issues originally appealed remained. The Court found against ComEd on each of the remaining issues: compensation related adjustments, billing determinants and the use of certain allocators. The Court s opinion has no accounting impact as ComEd recorded the distribution formula regulatory asset consistent with the ICC s final Order. On September 14, 2014, the Illinois Supreme Court declined to hear that appeal. ComEd elected not to seek review by the United States Supreme Court on the Federal law issues. Accordingly, the decision of the Illinois Appellate Court is considered final.

Grand Prairie Gateway Transmission Line (ComEd). 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. The costs incurred for the project prior to May 21, 2014 were immaterial. ComEd has acquired numerous easements across the project route through voluntary transactions. ComEd will seek to acquire the property rights on the remaining 28 parcels through condemnation proceedings in the circuit courts. ComEd began construction of the line during the second quarter of 2015 with an in-service date expected in the second quarter of 2017.

Illinois Procurement Proceedings (Exelon, Generation and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. As of December 31, 2015, ComEd has completed the ICC-approved procurement process for a portion of its energy requirements through 2021.

Combined Notes to Consolidated Financial Statements (Continued)

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

ComEd is required to purchase an increasing percentage of the electricity for customer deliveries from renewable energy resources. Purchases by customers of electricity from competitive electric generation suppliers, whether as a result of the customers own actions or as a result of municipal aggregation, are not included in this calculation and have the effect of reducing ComEd s purchase obligation. ComEd entered into several 20-year contracts with unaffiliated suppliers in December 2010 regarding the procurement of long-term renewable energy and associated RECs in order to meet its obligations under the Illinois RPS. All associated costs are recoverable from customers.

FutureGen Industrial Alliance, Inc (Exelon and ComEd). During 2013, the ICC approved, and directed ComEd and Ameren (the Utilities) to enter into 20-year sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The sourcing agreement provides that ComEd and Ameren will pay FutureGen s contract prices, which are set annually pursuant to a formula rate. The contract prices are based on the difference between the costs of the facility and the revenues FutureGen receives from selling capacity and energy from the unit into the MISO or other markets, as well as any other revenue FutureGen receives from the operation of the facility. The order also directs ComEd and Ameren to recover these costs from their electric distribution customers through the use of a tariff, regardless of whether they purchase electricity from ComEd or Ameren, or from competitive electric generation suppliers.

In February 2013, ComEd filed an appeal with the Illinois Appellate Court questioning the legality of requiring ComEd to procure power for retail customers purchasing electricity from competitive electric generation suppliers. On July 22, 2014, the Illinois Appellate Court issued its ruling re-affirming the ICC s order requiring ComEd to enter into the sourcing agreement with FutureGen and allowing the use of a tariff to recover its costs. ComEd decided not to appeal the Illinois Appellate Court s decision to the Illinois Supreme Court. However, the competitive electric generation suppliers and several large consumers petitioned for leave to appeal the Illinois Appellate Court s decision. On November 26, 2014, the Illinois Supreme Court granted the petition. ComEd executed the sourcing agreement with FutureGen in accordance with the ICC s order. In addition, ComEd filed a petition with the ICC seeking approval of the tariff allowing for the recovery of its costs associated with the FutureGen contract from all of its electric distribution customers, which was approved by the ICC on September 30, 2014.

A significant portion of the cost of the development of FutureGen was being funded by the DOE under the American Recovery and Reinvestment Act of 2009. In early February 2015, the DOE suspended funding for the project until further clarity could be obtained on certain significant hurdles facing the project, including the outcome of the litigation described above. Whether or not the DOE funding will be reinstated at some later date is unknown at this time.

On January 13, 2016, FutureGen informed the Illinois Supreme Court that it had ceased all development efforts on the FutureGen project and would soon be seeking to terminate the FutureGen supply agreements. Accordingly, FutureGen requested that the court dismiss the proceeding as moot. A decision from the Illinois Supreme Court dismissing the matter is expected in early 2016. In February 2016, FutureGen terminated its sourcing agreement with ComEd. As a result, ComEd is under no further obligation under this agreement.

Energy Efficiency and Renewable Energy Resources (Exelon and ComEd). Electric utilities in Illinois are required to include cost-effective energy efficiency resources in their plans to meet an

Combined Notes to Consolidated Financial Statements (Continued)

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

incremental annual program energy savings requirement of 2% of energy delivered in the year commencing June 1, 2015 and each year thereafter. Additionally, during the ten-year period that began June 1, 2008, electric utilities must implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers. The energy efficiency and demand response goals are subject to rate impact caps each year. Utilities are allowed recovery of costs for energy efficiency and demand response programs, subject to approval by the ICC. In 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.

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, 2015, 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.

Pennsylvania Regulatory Matters

2015 Pennsylvania Electric Distribution Rate Case (Exelon and PECO). On March 27, 2015, PECO filed a petition with the PAPUC requesting an increase of $190 million to its annual service revenues for electric delivery, which requested an ROE of 10.95%. On September 10, 2015, PECO and interested parties filed with the PAPUC a petition for joint settlement for an increase of $127 million in annual distribution service revenue. No overall ROE was specified in the settlement. On December 17, 2015, the PAPUC approved the settlement of PECO s electric distribution rate case. The approved electric delivery rates became effective on January 1, 2016.

The settlement includes approval of the In-Program Arrearage Forgiveness (IPAF) Program, which provides for forgiveness of a portion of the eligible arrearage balance of its low-income Customer Assistance Program (CAP) accounts receivable that will be determined as of program inception in October 2016. The forgiveness will be granted to the extent CAP customers remain current with payments. The Settlement guarantees PECO s recovery of two-thirds of the arrearage balance through a combination of customer payments and rate recovery, including through future rates cases if necessary. The remaining one-third of the arrearage balance will be absorbed by PECO, of which a portion has already been expensed as bad debt for CAP customer s accounts receivable balances.

Combined Notes to Consolidated Financial Statements (Continued)

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

Although the actual arrearage balance is not defined until program inception, PECO believes that it can reasonably estimate certain CAP customer accounts receivable balances as of December 31, 2015 that will remain outstanding at program inception. Management determined its best estimate based on historical collectability information. As a result, a regulatory asset of $7 million, representing the previously incurred bad debt expense associated with the estimated eligible accounts receivable balances, was recorded on Exelon s and PECO s Consolidated Balance Sheets as of December 31, 2015. This estimate will be revisited on a quarterly basis through program inception.

2010 Pennsylvania Electric and Natural Gas Distribution Rate Cases (Exelon and PECO). On December 16, 2010, the PAPUC approved the settlement of PECO s electric and natural gas distribution rate cases, which were filed in March 2010, providing increases in annual service revenue of $225 million and $20 million, respectively.

The settlements included a stipulation regarding how tax benefits related to the application of any new IRS guidance on repairs deduction methodology are to be handled from a rate-making perspective. The settlements required that the expected cash benefit from the application of any new guidance to tax years prior to 2011 be refunded to customers over a seven-year period. On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for electric transmission and distribution property. PECO adopted the safe harbor and elected a method change for the 2010 tax year. The total refund to customers for the tax cash benefit from the application of the safe harbor to costs incurred prior to 2010 was $171 million. On October 4, 2011, PECO filed a supplement to its electric distribution tariff to execute the refund to customers of the tax cash benefit related to the IRC Section 481(a) catch-up adjustment claimed on the 2010 income tax return, which is subject to adjustment based on the outcome of IRS examinations. Credits have been reflected in customer bills since January 1, 2012.

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The expected total refund to customers for the tax cash benefit from the application of the new method to costs incurred prior to 2011 is $54 million. This amount is subject to adjustment based on the outcome of IRS examinations. Credits have been reflected in customer bills since January 1, 2013. PECO is awaiting IRS guidance that will provide a safe harbor method of accounting for gas transmission and distribution property.

The prospective tax benefits claimed as a result of the new methodology will be reflected in tax expense in the year in which they are claimed on the tax return. As agreed to in the 2010 distribution rate case settlements, these benefits were reflected in the determination of revenue requirements in the 2015 electric distribution rate case discussed above and will be reflected in the next natural gas distribution rate case. See Note 15 Income Taxes for additional information.

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

Pennsylvania Procurement Proceedings (Exelon and PECO). Through PECO s first two PAPUC approved DSP Programs, PECO procured electric supply for its default electric customers through PAPUC approved competitive procurements. DSP I and DSP II expired on May 31, 2013 and May 31, 2015, respectively.

The second DSP Program included a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed

261

Combined Notes to Consolidated Financial Statements (Continued)

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

to submit a plan to allow its low-income CAP customers to purchase their generation supply from EGSs beginning in April 2014. In May 2013, PECO filed its CAP Shopping Plan with the PAPUC. By an 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, the Office of Consumer Advocate (OCA) and 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 July 14, 2015, the Court issued opinions on the OCA and low-income advocacy group appeal. Specifically, the Court remanded the issue to the PAPUC with instructions that it approve a rule revision to the PECO CAP Shopping Plan that would prohibit CAP customers from entering into contracts with an EGS that would impose early cancellation/termination fees. The PAPUC has appealed the Court s decision. PECO does not have information at this time as to what action it may be required to take following remand to the PAPUC.

On December 4, 2014, the PAPUC approved PECO s third DSP Program. 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. Under the program, PECO is procuring 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. Beginning in June 2016, the medium commercial class (101-500 kW) will move to spot market pricing. As of December 31, 2015, PECO entered into contracts with PAPUC-approved bidders, including Generation, resulting from the first two of its four scheduled procurements. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO s Consolidated Statement of Operations and Comprehensive Income.

On March 12, 2015, PECO settled the CAP Design with the Office of Consumer Advocates (OCA) and Low Income Advocates, and filed the proposed plan with the PAPUC on March 20, 2015. The program design changes the rate structure of PECO s CAP to make the bills more affordable to customers enrolled in the assistance program. The CAP discounts continue to be recovered through PECO s universal service fund cost. On July 8, 2015, the CAP Design was approved by the PAPUC. PECO plans to implement the program changes in October 2016.

Smart Meter and Smart Grid Investments (Exelon and PECO). In April 2010, pursuant to Act 129 and the follow-on Implementation Order of 2009, the PAPUC approved PECO s Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million electric smart meters and an AMI communication network by 2020. PECO is currently in the second phase of the SMPIP and has deployed substantially all remaining smart meters as of December 31, 2015, for a total of 1.7 million smart meters. In total, PECO currently expects to spend up to $589 million, excluding the cost of the original meters, on its smart meter infrastructure and approximately $155 million on smart grid investments through final deployment of which $200 million has been funded by SGIG. As of December 31, 2015, PECO has spent $578 million and $155 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received. Recovery of smart meter costs will be reflected in base rates effective January 1, 2016.

Energy Efficiency Programs (Exelon and PECO). PECO s PAPUC-approved Phase I EE&C Plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I plan set forth how PECO would meet the required reduction targets established by Act 129 s EE&C provisions. On November 15, 2013, PECO filed its final compliance report with the PAPUC communicating PECO had met all Phase I reduction targets.

Combined Notes to Consolidated Financial Statements (Continued)

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

The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provided energy consumption reduction requirements for the second phase of Act 129 s EE&C program, which went into effect on June 1, 2013. Pursuant to the Phase II implementation order, PECO filed its three-year EE&C Phase II Plan with the PAPUC on November 1, 2012. The plan set forth how PECO would reduce electric consumption by at least 1,125,852 MWh in its service territory for the period June 1, 2013 through May 31, 2016, adjusted for weather and extraordinary loads. The implementation order permitted PECO to apply any excess savings achieved during Phase I against its Phase II consumption reduction targets, with no reduction to its Phase II budget. In accordance with the Act 129 Phase II implementation order, at least 10% and 4.5% of the total consumption reductions had to be through programs directed toward PECO s public and low income sectors, respectively. If PECO failed to achieve the required reductions in consumption, it would have been subject to civil penalties of up to $20 million, which would not be recoverable from ratepayers. Act 129 mandates that the total cost of the plan may not exceed 2% of the electric company s total annual revenue as of December 31, 2006.

On March 15, 2013 and February 28, 2014, PECO filed Petitions for Approval to amend its EE&C Phase II Plan to continue its DLC demand reduction program for mass market customers through May 31, 2014 and May 31, 2016, respectively. PECO proposed to fund the estimated $10 million annual costs of the plan by modifying incentive levels for other Phase II programs. The costs of the DLC program will be recovered through PECO s Energy Efficiency Plan surcharge along with other Phase II Plan costs. The PAPUC granted PECO s Petitions on May 5, 2013 and April 23, 2014, respectively.

The PAPUC issued its Phase III EE&C implementation order on June 19, 2015, that provides energy consumption reduction requirements for the third phase of Act 129 s EE&C program with a five-year term from June 1, 2016 through May 31, 2021. The order tentatively established PECO s five-year cumulative consumption reduction target at 2,080,553 MWh.

Pursuant to the Phase III implementation order, PECO filed its five-year EE&C Phase III Plan with the PAPUC on November 30, 2015. The Plan sets forth how PECO will reduce electric consumption by at least 1,962,659 MWh, with a goal of 2,100,875 MWh in its service territory for the period June 1, 2016 through May 31, 2021. PECO expects a final decision from the PAPUC on PECO s EE&C Phase III Plan during the first quarter of 2016.

Alternative Energy Portfolio Standards (Exelon and PECO). In November 2004, Pennsylvania adopted the AEPS Act. The AEPS Act mandated that beginning in 2011, following the expiration of PECO s rate cap transition period, certain percentages of electric energy sold to Pennsylvania retail electric customers shall be generated from certain alternative energy resources as measured in AECs. The requirement for electric energy that must come from Tier I alternative energy resources ranges from approximately 3.5% to 8%, and the requirement for Tier II alternative energy resources ranges from 6.2% to 10%. The required compliance percentages incrementally increase each annual compliance period, which is from June 1 through May 31, until May 31, 2021. These Tier I and Tier II alternative energy resources include acceptable energy sources as set forth in Act 129 and the AEPS Act.

PECO continues to procure alternative energy credits through full requirements contracts and its existing long-term solar contracts to meet the annual AEPS compliance requirements. All AEPS compliance costs are being recovered on a full and current basis from default service customers through the GSA.

263

Combined Notes to Consolidated Financial Statements (Continued)

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

Pennsylvania Retail Electricity and Gas Markets (Exelon and PECO). Beginning in 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania s retail electricity market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed its Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. Through various orders, the PAPUC issued default electric service pricing for customers in PECO s service territory. See Pennsylvania procurement proceedings discussed above for additional details.

In early 2014, the extreme weather in PECO s service territory resulted in increased electricity 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 contract. 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.

On September 12, 2013, the PAPUC issued an Order that initiated an investigation into Pennsylvania s natural gas retail market, including the role of the existing default service model and opportunities for market enhancements. On December 18, 2014, the PAPUC issued a Final Order directing the Office of Competitive Market Oversight (OCMO) to continue its investigation, confirming that natural gas distribution companies should remain with the default service model for the time being and directing establishment of a working group to examine other competitive issues. The OCMO has established a working group to review operation of the natural gas retail market and to consider potential recommendations on competitive issues.

Pennsylvania Act 11 of 2012 (Exelon and PECO). In February 2012, Act 11 was signed into law, which provided the PAPUC authority to approve the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities aging electric and natural gas distribution systems in Pennsylvania. Prior to recovering costs pursuant to a DSIC, the PAPUC s implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) approved by the Commission, which outlines how the utility is planning to increase its investment for repairing, improving or replacing aging infrastructure.

On May 7, 2015, the PAPUC approved PECO s modified natural gas LTIIP. In accordance with the approved LTIIP, PECO plans to spend $534 million through 2022 to further accelerate the replacement of existing gas mains and to relocate meters from indoors to outside in accordance with recent PAPUC rulemaking. In addition, on March 20, 2015, PECO filed a petition with the PAPUC for approval of its gas DSIC mechanism for recovery of gas LTIIP expenditures. On September 11, 2015, the PAPUC entered its Opinion and Order approving PECO s petition for a gas DSIC.

On March 27, 2015, PECO filed a petition with the PAPUC for approval of its proposed electric DSIC and LTIIP. In accordance with the LTIIP (System 2020 plan), PECO plans to spend $275 million over the next five years to modernize and storm-harden its electric distribution system, making it more

Combined Notes to Consolidated Financial Statements (Continued)

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

weather resistant and less vulnerable to damage. The DSIC will allow PECO the opportunity to recover the costs, subject to certain criteria, incurred to repair, improve or replace its electric distribution property between rate cases. On October 22, 2015, the PAPUC entered its Opinion and Order approving PECO s proposed petition for its electric LTIIP and DSIC.

Maryland Regulatory Matters

2015 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On November 6, 2015, and as amended on January 5, 2016, BGE filed for electric and gas base rate increases with the MDPSC, ultimately requesting an increase of $121 million and $79 million, respectively, of which $103 million and $37 million, respectively, is related to recovery of smart grid initiative costs. BGE requested a ROE for the electric and gas distribution rate case of 10.6% and 10.5%, respectively. The new electric and gas base rates are expected to take effect in June 2016. BGE is also proposing to recover an annual increase of approximately $30 million for Baltimore City conduit lease fees through a surcharge. BGE cannot predict how much of the requested increase the MDPSC will approve or if it will approve BGE s request for a conduit fee surcharge.

2014 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 2, 2014, and as amended on September 15, 2014, BGE filed for electric and gas base increases with the MDPSC, ultimately requesting increases of $99 million and $68 million, respectively.

On October 17, 2014, BGE filed with the MDPSC a unanimous settlement agreement (the Settlement Agreement) reached with all parties to the case under which it would receive an increase of $22 million in electric base rates and an increase of $38 million in gas base rates. The Settlement Agreement establishes new depreciation rates which have the effect of decreasing annual depreciation expense by approximately $20 million, primarily for electric. 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 distribution rate order authorizing BGE to increase electric and gas distribution rates became effective for services rendered on or after December 15, 2014.

2013 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On May 17, 2013, and as amended on August 23, 2013, BGE filed for electric and gas base increases with the MDPSC, ultimately requesting increases of $83 million and $24 million, respectively. In addition to these requested rate increases, BGE s application includes a request for recovery of incremental capital expenditures and operating costs associated with BGE s proposed short-term reliability improvement plan (the ERI initiative) in response to a MDPSC order through a surcharge separate from base rates.

On December 13, 2013, the MDPSC issued an order in BGE s 2013 electric and natural gas distribution rate case for increases in annual distribution service revenue of $34 million and $12 million, respectively, and an allowed return on equity of 9.75% and 9.60%, respectively. Rates became effective for services rendered on or after December 13, 2013. The MDPSC also authorized BGE to recover through a surcharge mechanism costs associated with five ERI initiative programs designed to accelerate electric reliability improvements premised upon the condition that the MDPSC approve specific projects in advance of cost recovery. On March 31, 2014, after reviewing comments filed by the parties and conducting a hearing on the matter, the MDPSC approved all but one project proposed for completion in 2014 as part of the ERI initiative. The ERI initiative surcharge became effective June 1, 2014. On November 2, 2015, BGE filed a surcharge update including a true-up of cost estimates included in the 2015 surcharge, along with its work plan and cost estimates for 2016, to be included in the 2016 surcharge. The MDPSC subsequently approved BGE s 2016 work plan and the 2016 surcharge.

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

In January 2014, the residential consumer advocate in Maryland filed an appeal to the order issued by the MDPSC on December 13, 2013 in BGE s 2013 electric and gas distribution rate cases. The residential consumer advocate filed its related legal memorandum on August 22, 2014, challenging the MDPSC s approval of the ERI initiative surcharge. BGE submitted a response to the appeal on October 15, 2014, and a hearing was held on November 17, 2014. On October 26, 2015, the Circuit Court for Baltimore City issued an order affirming the MDPSC s decision. However, on November 30, 2015, the residential consumer advocate filed an appeal of the Circuit Court s decision with the Maryland Court of Special Appeals. BGE cannot predict the outcome of this appeal. If the residential consumer advocate s appeal is successful, BGE could recover ERI expenditures through other regulatory mechanisms.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million of which $200 million was funded by SGIG. The MDPSC s approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of December 31, 2015 and December 31, 2014, BGE recorded a regulatory asset of $196 million and $128 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. As part of the settlement in BGE s 2014 electric and gas distribution rate case, the cost of the retired non-AMI meters will be amortized over 10 years.

On February 26, 2014, the MDPSC issued an order authorizing BGE to impose a $75 upfront fee and an $11 recurring fee to customers electing to opt-out of BGE s smart meter installation program, effective the later of the first full billing cycle following July 1, 2014, or the AMI installation date in a customer s community. The fees authorized by the order will be reviewed after an initial 12 to 18 month period. On November 25, 2014, the MDPSC issued a decision approving BGE s proposal to automatically enroll unresponsive customers into the opt-out program and to charge those customers opt-out fees after BGE has exhausted attempts to schedule a meter installation. On November 5, 2015, the MDPSC held a hearing to evaluate the $11 recurring monthly fee paid by opt-out customers. Effective with January 2016 bills, the monthly recurring fee was reduced to $5.50.

As part of the 2015 electric and gas distribution rate case filed on November 6, 2015, BGE is seeking recovery of its smart grid initiative costs. Of BGE s requested $200 million, $140 million relates to the smart grid initiative. In support of its recovery of smart grid initiative costs, BGE provided evidence demonstrating that the benefits exceed the costs by a ratio of 2.3 to 1.0, on a nominal basis.

New Electric Generation (Exelon and BGE). On April 12, 2012, the MDPSC issued an order directing BGE and two other Maryland utilities to enter into a contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700MW natural gas-fired combined-cycle generation plant in Waldorf, Maryland, that CPV projected will be in commercial operation by June 1, 2015. CPV subsequently sought to extend that date. The initial term of the proposed contract is 20 years. The CfD mandates that BGE and the other utilities pay (or receive) the difference between CPV s contract prices and the revenues CPV receives for capacity and energy from clearing the unit in the PJM capacity market. The MDPSC s order requires the three Maryland utilities to enter into a CfD in amounts proportionate to their relative SOS load. On April 16, 2013, the MDPSC issued an order that required BGE to execute a specific form of contract with CPV, and the parties executed the contract as of June 6, 2013.

On April 27, 2012, a civil complaint was filed in the U.S. District Court for the District of Maryland by certain unaffiliated parties that challenged the actions taken by the MDPSC on Federal law grounds. On

266

Combined Notes to Consolidated Financial Statements (Continued)

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

October 24, 2013, the U.S. District Court issued a judgment order finding that the MDPSC s Order directing BGE and the two other Maryland utilities to enter into a CfD, which assures that CPV receives a guaranteed fixed price regardless of the price set by the federally regulated wholesale market, violates the Supremacy Clause of the United States Constitution. On November 22, 2013, the MDPSC and CPV appealed the District Court s ruling to the United States Court of Appeals for the Fourth Circuit. The Fourth Circuit affirmed the District Court ruling in an opinion issued June 2, 2014. The MDPSC and CPV filed petitions for certiorari, seeking review of the case by the U.S. Supreme Court. On October 29, 2015, the U.S. Supreme Court granted the petition to review the Fourth Circuit decision, and that appeal is now pending in the Supreme Court with oral argument scheduled for February 24, 2016.

On February 9, 2011, a civil complaint was filed by Exelon and other unaffiliated parties in the United States District Court for the District of New Jersey, challenging a 2011 New Jersey law, 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. On October 25, 2013, the U.S. District Court issued a judgment order finding that LCAPP violates the Supremacy Clause of the United States Constitution. CPV and New Jersey appealed the District Court s ruling to the United States Court of Appeals for the Third Circuit. On September 11, 2014, the Third Circuit affirmed the District Court s ruling finding LCAPP unconstitutional. On November 26, 2014, CPV and New Jersey sought Supreme Court review of the Third Circuit decision. On October 29, 2015, the Supreme Court stayed the petition to review the Third Circuit case pending their review of the Fourth Circuit Maryland case described above.

On May 4, 2012, BGE filed a petition in the Circuit Court for Anne Arundel County, Maryland, seeking judicial review of the MDPSC order under state law. That petition was subsequently transferred to the Circuit Court for Baltimore City and consolidated with similar appeals that have been filed by other interested parties. On October 1, 2013, the Circuit Court Judge issued a Memorandum Opinion and Order finding the decisions of the MDPSC were within its statutory authority under Maryland law. This decision is separate from the judgment in the federal litigation that the MDPSC Order is unconstitutional and the CfD is unenforceable under federal law. The federal judgment, if upheld, would prevent enforcement of the CfD even if the Circuit Court decision stands. On October 29, 2013, BGE and the two other Maryland utilities appealed the Circuit Court s ruling to the Maryland Court of Special Appeals. That appeal has been stayed pending decision by the U.S. Supreme Court in the federal action described above.

Depending on the ultimate outcome of the pending state and federal litigation, on the eventual market conditions, and on the manner of cost recovery as of the effective date of the agreement, the CfD could have a material impact on Exelon and BGE s results of operations, cash flows and financial positions.

Exelon believes that this and other states projects may have artificially suppressed capacity prices in PJM and may continue to do so in future auctions to the detriment of Exelon s market driven position. In addition to this litigation, Exelon is working with other market participants to implement market rules that will appropriately limit the market suppressing effect of such state activities.

MDPSC Derecho Storm Order (Exelon and BGE). Following the June 2012 Derecho storm which hit the mid-Atlantic region interrupting electrical service to a significant portion of the State of Maryland, the MDPSC issued an order on February 27, 2013 requiring BGE and other Maryland utilities to file several comprehensive reports with short-term and long-term plans to improve reliability and grid resiliency that were due at various times before August 30, 2013.

267

Combined Notes to Consolidated Financial Statements (Continued)

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

On September 3, 2013, BGE filed a comprehensive long term assessment examining potential alternatives for improving the resiliency of the electric grid and a staffing analysis reviewing historical staffing levels as well as forecasting staffing levels necessary under various storm scenarios. During the summer of 2014, an evaluation of the reports filed by BGE and other Maryland utilities was undertaken by consultants on behalf of the MDPSC and MDPSC Staff. The MDPSC Staff also proposed standards for reliability during major events and estimated times of restoration as well as undertaking an evaluation of performance-based ratemaking principles and methodologies that would more directly and transparently align reliable service with the utilities distribution rates and that reduce returns or otherwise penalize sub-standard performance. The MDPSC held hearings in September 2014. BGE currently cannot predict the outcome of these proceedings, which may result in increased capital expenditures and operating costs.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In 2013, legislation intended to accelerate gas infrastructure replacements in Maryland was signed into law. The law established a mechanism, separate from base rate proceedings, for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects incurred after June 1, 2013. The monthly surcharge and infrastructure replacement costs must be approved by the MDPSC and are subject to a cap and 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 November 16, 2015, BGE filed a surcharge update to be effective January 1, 2016, including a true-up of cost estimates included in the 2015 surcharge, along with its 2016 project list and projected capital estimates of $113 million to be included in the 2016 surcharge calculation. The MDPSC subsequently approved BGE s 2016 project list and the proposed surcharge for 2016, which included the 2015 surcharge true-up. As of December 31, 2015, BGE recorded a regulatory asset of less than $1 million, representing the difference between the surcharge revenues and program costs.

In 2014, the residential consumer advocate in Maryland appealed MDPSC s decision on BGE s infrastructure replacement plan and associated surcharge with the Baltimore City Circuit Court, who affirmed the MDPSC s decision. 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. During the third quarter of 2015, the residential consumer advocate, MDPSC and BGE filed briefs. Oral argument in this matter was held before the Court of Special Appeals on November 3, 2015. On January 28, 2016, the Maryland Court of Special Appeals issued a decision affirming the MDPSC s decision.

New York Regulatory Matters

Ginna Nuclear Power Plant Reliability Support Services Agreement (Exelon and Generation). Ginna Nuclear Power Plant s (Ginna) prior period fixed-price PPA contract with Rochester Gas & Electric Company (RG&E) expired in June 2014. In light of the expiration of the PPA and prevailing market conditions, in January 2014, Ginna advised the New York Public Service Commission (NYPSC) and the ISO-NY that, in the absence of a reliability need, Ginna management

268

Combined Notes to Consolidated Financial Statements (Continued)

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

would make a recommendation, subject to approval by the CENG board, that the Ginna plant be retired as soon as practicable. A formal study conducted by the ISO-NY and RG&E dated as of May 12, 2014 concluded that Ginna needs to remain in operation to maintain the reliability of the transmission grid in the Rochester region through September 2018 when planned transmission system upgrades undertaken by RG&E are expected to be completed.

In November 2014, in response to a petition filed by Ginna, the NYPSC directed Ginna and RG&E to negotiate a Reliability Support Services Agreement (RSSA). In February 2015, regulatory filings, including RSSA terms negotiated between Ginna and RG&E, to support the continued operation of Ginna for reliability purposes were made with the NYPSC and with the FERC for their approval. Although the RSSA contract is still subject to such regulatory approvals, on April 1, 2015, Ginna began delivering the power and capacity from the Ginna plant into the ISO-NY consistent with the technical provisions of the proposed RSSA contract.

In April 2015, the FERC issued an order which directed Ginna to make a compliance filing to ensure that the RSSA does not allow Ginna to receive revenues above its full cost of service and which rejected any extension of the RSSA beyond its initial term; rather the order required that any extension be subject to the rules currently being developed by the ISO-NY. The FERC order also set the RSSA for hearing and settlement procedures. In response to the FERC s April 2015 order, in May 2015, Ginna submitted a compliance filing to the FERC containing proposed revisions to the RSSA addressing the FERC s requirements and maintaining the April 1, 2015 proposed effective date. In July 2015, the FERC accepted Ginna s compliance filing effective April 1, 2015. The FERC accepted Ginna s proposal for market revenue sharing subject to a cap effective April 1, 2015, and rejected requests for rehearing by intervenors on a number of matters related to jurisdiction, the reliability need, the RSSA term, and possible price suppression.

In August 2015, Ginna reached a settlement in principle with intervenors modifying certain terms and conditions in the originally negotiated agreement. The proposed RSSA under the settlement preserves the value of the contract originally negotiated with RG&E, but shortens the term from 3.5 to 2 years, expiring March 31, 2017 and required RG&E to complete a new transmission reliability study to determine whether an interim reliability solution is required beyond March 31, 2017. That reliability study was completed in October 2015, and it identified certain RG&E projects that are needed to solve reliability problems that would be caused by an early retirement of Ginna. Under the settlement agreement, Ginna was required by December 29, 2015 to submit a bid to provide reliability services beginning April 1, 2017 until the necessary RG&E transmission upgrades are in service, which RG&E expects will be no later than October 31, 2017. Ginna submitted such a bid in December 2015. RG&E has the right until June 30, 2016 to select Ginna as an ongoing reliability solution. If such a need exists, and if Ginna is selected, Ginna and RG&E could enter into an additional RSSA commencing April 1, 2017 on the rates, terms and conditions set forth in Ginna s bid, or as might be otherwise agreed by Ginna and RG&E.

If RG&E seeks a reliability solution with Ginna, but RG&E and Ginna do not reach an agreement on rates, terms, and conditions of a new RSSA by March 31, 2016 (or by June 30, 2016 if RG&E elects to defer the decision date), the settlement agreement requires Ginna to file an unexecuted additional RSSA with the FERC for adjudication. If Ginna is not selected for continued reliability service and does not plan to retire shortly after the expiration of the RSSA, Ginna is required to file a notice to that effect with the NYPSC no later than September 30, 2016. Under the terms of the proposed RSSA, if RG&E does not select Ginna to provide reliability service after March 31, 2017, and Ginna continues to operate after June 14, 2017, Ginna would be required to make certain refund payments related to capital expenditures to RG&E.

Combined Notes to Consolidated Financial Statements (Continued)

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

The August 2015 settlement was filed at the NYPSC and at the FERC in October 2015 and remains subject to review and approval by both agencies; such reviews are not expected to be completed until the first quarter of 2016.

Until final regulatory approvals are received, Generation is recognizing revenue based on market prices for energy and capacity delivered by Ginna into the ISO-NY. Upon receiving regulatory approvals, under the RSSA contract terms, Generation would then recognize revenue based on the final approved pricing contained in the contract retroactively from the April 1, 2015 effective date. While the RSSA is expected to receive regulatory approvals and, therefore, permit Ginna to continue operating through the RSSA term, there is still a risk that, for economic reasons, including the possibility that the FERC or the NYPSC may condition the approval of the RSSA on a modification of the rates set forth in the RSSA, Ginna could be retired before 2029, which is the end of its operating license period. In the event the plant were to be retired before the current license term ends in 2029, Exelon s and Generation s results of operations could be adversely affected by accelerated future decommissioning costs, severance costs, increased depreciation rates, and impairment charges, among other items. However, it is not expected that such impacts would be material to Exelon s or Generation s results of operations.

Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd and BGE). ComEd s and BGE s transmission rates are each established based on a FERC-approved formula. ComEd and BGE are required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rates effective on June 1 of the same year. The 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 in effect beginning June 1 of the prior year and actual costs incurred for that year. ComEd and BGE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd s and BGE s best estimate of the revenue requirement expected to be filed with the FERC for that year s reconciliation. As of December 31, 2015, and 2014, ComEd had a regulatory asset associated with the transmission formula rate of $31 million and $21 million, respectively. As of December 31, 2015, and 2014, BGE had a net regulatory asset associated with the transmission formula rate of $12 million and $1 million, respectively. The regulatory asset associated with transmission true-up is amortized to Operating revenues within their Consolidated Statements of Operations of Comprehensive Income as the associated amounts are recovered through rates.

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

For each of the following years, the following total increases/(decreases) were included in ComEd s and BGE s electric transmission formula rate filings:

Annual Transmission Filings	ComEd 2015	ComEd 2014	ComEd 2013	BGE 2015	BGE 2014	BGE 2013
Initial revenue requirement increase [a]	$ 68	$ 36	$ 38	$	$ 9	$ 2
Annual reconciliation (decrease) increase	18	(14)	30	(3)	5	(3)
Total revenue requirement increase	$ 86	$ 22	$ 68	$ (3)	$ 14	$ (1)
Allowed return on rate base [b]	8.61%	8.62%	8.7%	8.46%	8.53%	8.35%
Allowed ROE	11.5%	11.5%	11.5%	11.3%	11.3%	11.3%
Effective date of rates [c]	June 2015	June 2014	June 2013	June 2015	June 2014	June 2013

(a) For BGE, this excludes the increase in revenue requirement associated with dedicated facilities charges. The increases for dedicated facilities were $13 million and $3 million for 2015 and 2014, respectively. There were no dedicated facilities charges in 2013 for BGE.
(b) Refers to the weighted average debt and equity return on transmission rate bases for ComEd and BGE. As part of the FERC-approved settlement of ComEd s 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of BGE s 2005 transmission rate case, the rate of return on common equity is 11.30%, inclusive of a 50 basis point incentive for participating in PJM.
(c) The time period for any challenges to the annual transmission formula rate update filings expired with no challenges submitted.

FERC Transmission Complaint (Exelon and BGE). On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the PHI 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 (and certain additional incentive basis points on certain projects). The parties sought a reduction in the base return on equity to 8.7% and changes to the formula rate process. Under FERC rules, any revenues subject to refund are limited to a fifteen month period and the earliest date from which the base ROE could be adjusted and refunds required is the date of 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.

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 reduction from 10.8% to 8.8%. The filing of the second complaint created 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. On February 20, 2015, the Chief Judge issued an order consolidating the two complaint proceedings and established an Initial Decision issuance deadline of February 29, 2016.

On November 6, 2015, BGE and the PHI companies and the complainants filed a settlement with FERC covering the issues raised in the complaints. The settlement provides for a 10% base ROE, effective March 8, 2016, which will be augmented by the PJM incentive adder of 50 basis points, and refunds to BGE customers of $13.7 million. The settlement also provides a moratorium on any change in the ROE until June 1, 2018. On December 16, 2015, the Presiding Administrative Law Judge submitted a Certification of the Uncontested Settlement to the FERC Commissioners. The settlement remains subject to FERC approval.

Combined Notes to Consolidated Financial Statements (Continued)

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

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM s current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. A number of parties appealed to the U.S. Court of Appeals for the Seventh Circuit for review of the decision.

In August 2009, the court issued its decision affirming the FERC s order with regard to the existing facilities, but remanded to FERC the issue of the cost allocation associated with the new facilities 500 kV and above (Cost Allocation Issue) for further consideration by the FERC. On remand, FERC reaffirmed its earlier decision to socialize the costs of new facilities 500 kV and above. A number of parties filed appeals of these orders. In June 2014, the court again remanded the Cost Allocation Issue to FERC. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the Cost Allocation Issue. The hearing only concerns new facilities approved by the PJM Board prior to February 1, 2013. As of December 31, 2015, settlement discussions are continuing.

Because a new cost allocation had been adopted for projects approved by the PJM Board on or after February 1, 2013, this latest remand only involves the cost allocation for facilities 500 kV and above approved prior to that date. ComEd anticipates that all impacts of any rate design changes effective after December 31, 2006, should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on ComEd s results of operations, cash flows or financial position. PECO anticipates that all impacts of any rate design changes should be recoverable through the transmission service charge rider approved in PECO s 2010 electric distribution rate case settlement and, thus, the rate design changes are not expected to have a material impact on PECO s results of operations, cash flows or financial position. To the extent any rate design changes are retroactive to periods prior to January 1, 2011, there may be an impact on PECO s results of operations. BGE anticipates that all impacts of any rate design changes effective after the implementation of its standard offer service programs in Maryland should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on BGE s results of operations, cash flows or financial position.

ComEd, PECO and BGE are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. ComEd, PECO and BGE will work with PJM to continue to evaluate the scope and timing of any required construction projects. ComEd, PECO and BGE s estimated commitments are as follows:

	Total	2016	2017	2018	2019	2020
ComEd	$ 297	$ 204	$ 61	$ 26	$ 6	$
PECO	67	31	24	8	4	
BGE	373	140	112	62	46	13

Demand Response Resource Order (Exelon, Generation, ComEd, PECO, BGE). On May 23, 2014, the D.C. Circuit Court issued an opinion vacating the FERC Order No. 745 (D.C. Circuit Decision). Order No. 745 established uniform compensation levels for demand response resources

272

Combined Notes to Consolidated Financial Statements (Continued)

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

that participate in the day ahead and real-time wholesale energy markets. Under Order No. 745, buyers in ISO and RTO markets were required to pay demand response resources the full Locational Marginal Price when the demand response replaced a generation resource and was cost-effective. On January 25, 2016, the U.S. Supreme Court reversed the D.C. Circuit Court decision and remanded the matter to the D.C. Circuit Court. While we cannot predict exactly how the D.C. Circuit Court will handle the matter on remand, we do not expect there will be any significant change in how demand response resources have or will participate in and be paid by wholesale energy markets. Thus, we do not anticipate that there will be any impact to the Registrants results of operations or cash flows based on these proceedings.

New England Capacity Market Results (Exelon and Generation). Each year, ISO New England, Inc. (ISO-NE) files the results of its annual capacity auction at the FERC which is required to include documentation regarding the competitiveness of the auction. Consistent with this requirement, on February 27, 2015, ISO-NE filed the results of its ninth capacity auction (covering the June 1, 2018 through May 31, 2019 delivery period). On June 18, 2015, the FERC accepted the results of the ninth capacity auction. On July 20, 2015, a union representing utility workers sought rehearing of that decision which the FERC denied on December 30, 2015. It is not clear whether the FERC s order will be appealed.

On February 28, 2014, ISO-NE filed the results of its eighth capacity auction (covering the June 1, 2017 through May 31, 2018 delivery period). On June 27, 2014, the FERC issued a letter to ISO-NE noting that ISO-NE s February 28, 2014 filing was deficient and that ISO-NE must file additional information before the FERC can process the filing. ISO-NE filed the information on July 17, 2014, and the ISO-NE s filings became effective by operation of law pursuant to a notice issued by the secretary of FERC on September 16, 2014. Several parties sought rehearing of the secretary s notice which was effectively denied in October 2014 and have since appealed the matter to the D.C. Circuit Court. On April 7, 2015 the D.C. Circuit Court issued an order referring the matter to a merits panel where issues raised by parties challenging the FERC decision will be heard as well as FERC s Motion to Dismiss the challenges. It is not clear whether the court will decide ultimately on the merits of the case or whether it will dismiss the case as FERC urges based on the fact that there is no action by the FERC to be considered. Nonetheless, while any change in the auction results is thought to be unlikely, Exelon and Generation cannot predict with certainty what further action the court may take concerning the results of that auction, but any court action could be material to Exelon s and Generation s expected revenues from the capacity auction.

License Renewals (Exelon and Generation). Generation has 40-year operating licenses from the NRC for each of its nuclear units. The operating license renewal process takes approximately four to five years from the commencement of the renewal process until completion of the NRC s review.

On May 29, 2013, Generation submitted applications to the NRC to extend the current operating licenses of Byron Units 1 and 2 and Braidwood Units 1 and 2 by 20 years. On November 19, 2015, the NRC approved Generation s request to extend the operating licenses of Byron Unit 1 and 2 by 20 years to 2044 and 2046, respectively. On January 27, 2016 the NRC approved Generation s request to extend the operating licenses of Braidwood Unit 1 and 2 by 20 years to 2046 and 2047, respectively.

On December 09, 2014, Generation submitted an application to the NRC to extend the current operating licenses of LaSalle Units 1 and 2, which were set to expire in 2022 and 2023, respectively.

On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy

Combined Notes to Consolidated Financial Statements (Continued)

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

Run Pumped Storage Project (Muddy Run), respectively. On December 22, 2015, FERC issued a new 40-year license for Muddy Run. The license term expires on December 1, 2055. The financial impact associated with Muddy Run license commitments is estimated to be in the range of an incremental $25 million to $35 million, and includes both capital expenditures and operating expenses, primarily relating to fish passage and habitat improvement projects. At December 31, 2015, $22 million of direct costs associated with the licensing effort have been capitalized.

Generation is working with stakeholders to resolve water quality licensing issues with the MDE for Conowingo, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. On January 30, 2014, Generation filed a water quality certification application pursuant to Section 401 of the CWA with MDE for Conowingo, addressing these and other issues, although Generation cannot currently predict the conditions that ultimately may be imposed. MDE indicated that it believed it did not have sufficient information to process Generation s application. As a result, Generation entered into an agreement with MDE to work with state agencies in Maryland, the U.S. Army Corps of Engineers, the U.S. Geological Survey, the University of Maryland Center for Environmental Science and the U.S. Environmental Protection Agency Chesapeake Bay Program to design, conduct and fund an additional multi-year sediment study. Generation has agreed to contribute up to $3.5 million to fund the additional study. Because states must act on applications under Section 401 of the CWA within one year and the sediment study would not be completed prior to January 31, 2015, Exelon withdrew its application for a water quality certification on December 4, 2014. FERC policy requires that an applicant resubmit its request for a water quality certification within 90 days of the date of withdrawal. Accordingly, on March 3, 2015, Generation refiled its application for a water quality certification. Exelon has agreed with MDE to withdraw and refile its application for a water quality certification as necessary pending completion of the sediment study. On August 7, 2015, US Fish and Wildlife Service (USFWS) submitted its modified fishway prescription to FERC in the Conowingo licensing proceedings. On September 11, 2015, Exelon filed a request for an administrative hearing and proposed an alternative prescription to challenge USFWS s preliminary prescription. Resolution of these issues relating to Conowingo may have a material effect on Exelon s and Generation s results of operations and financial position through an increase in capital expenditures and operating costs.

The FERC license for Conowingo expired on September 1, 2014. Under the Federal Power Act, FERC is required to issue an annual license for a facility until the new license is issued. On September 10, 2014, FERC issued an annual license for Conowingo, effective as of the expiration of the previous license. If FERC does not issue a new license prior to the expiration of an annual license, the annual license will renew automatically. On March 11, 2015, FERC issued the final Environmental Impact Statement for Conowingo. The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. As of December 31, 2015, $23 million of direct costs associated with licensing efforts have been capitalized.

Regulatory Assets and Liabilities (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of December 31, 2015 and 2014.

December 31, 2015	Exelon	ComEd	PECO	BGE
Regulatory assets				
Pension and other postretirement benefits	$ 3,156	$	$	$
Deferred income taxes	1,616	64	1,473	79
AMI programs	399	140	63	196
Under-recovered distribution service costs	189	189		
Debt costs	47	46	1	8
Fair value of BGE long-term debt	162			
Severance	9			9
Asset retirement obligations	108	67	22	19
MGP remediation costs	286	255	30	1
Under-recovered uncollectible accounts	52	52		
Renewable energy	247	247		
Energy and transmission programs	84	43	1	40
Deferred storm costs	2			2
Electric generation-related regulatory asset	20			20
Rate stabilization deferral	87			87
Energy efficiency and demand response programs	279		1	278
Merger integration costs	6			6
Conservation voltage reduction	3			3
Under-recovered revenue decoupling	30			30
CAP arrearage	7		7	
Other	35	10	19	3
Total regulatory assets	6,824	1,113	1,617	781
Less: current portion	759	218	34	267
Total noncurrent regulatory assets	$ 6,065	$ 895	$ 1,583	$ 514

December 31, 2015	Exelon	ComEd	PECO	BGE
Regulatory liabilities				
Other postretirement benefits	$ 94	$	$	$
Nuclear decommissioning	2,577	2,172	405	
Removal costs	1,527	1,332		195
Energy efficiency and demand response programs	92	52	40	
DLC program costs	9		9	
Electric distribution tax repairs	95		95	
Gas distribution tax repairs	28		28	
Energy and transmission programs	131	53	60	18
Over-recovered revenue decoupling	1			1
Other	16	5	2	8

Total regulatory liabilities	4,570	3,614	639	222
Less: current portion	369	155	112	38
Total noncurrent regulatory liabilities	$ 4,201	$ 3,459	$ 527	$ 184

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

December 31, 2014	Exelon	ComEd	PECO	BGE
Regulatory assets				
Pension and other postretirement benefits	$ 3,256	$	$	$
Deferred income taxes	1,542	64	1,400	78
AMI programs	296	91	77	128
Under-recovered distribution service costs	371	371		
Debt costs	57	53	4	9
Fair value of BGE long-term debt	190			
Severance	12			12
Asset retirement obligations	116	74	26	16
MGP remediation costs	257	219	37	1
Under-recovered uncollectible accounts	67	67		
Renewable energy	207	207		
Energy and transmission programs	48	33		15
Deferred storm costs	3			3
Electric generation-related regulatory asset	30			30
Rate stabilization deferral	160			160
Energy efficiency and demand response programs	248			248
Merger integration costs	8			8
Conservation voltage reduction	2			2
Under-recovered revenue decoupling	7			7
Other	46	22	14	7
Total regulatory assets	6,923	1,201	1,558	724
Less: current portion	847	349	29	214
Total noncurrent regulatory assets	$ 6,076	$ 852	$ 1,529	$ 510

December 31, 2014	Exelon	ComEd	PECO	BGE
Regulatory liabilities				
Other postretirement benefits	$ 88	$	$	$
Nuclear decommissioning	2,879	2,389	490	
Removal costs	1,566	1,343		223
Energy efficiency and demand response programs	59	25	34	
DLC program costs	10		10	
Electric distribution tax repairs	102		102	
Gas distribution tax repairs	49		49	
Energy and transmission programs	84	19	58	7
Revenue subject to refund	3	3		
Over-recovered revenue decoupling	12			12
Other	8	1	4	2
Total regulatory liabilities	4,860	3,780	747	244
Less: current portion	310	125	90	44
Total noncurrent regulatory liabilities	$ 4,550	$ 3,655	$ 657	$ 200

Pension and other postretirement benefits. As of December 31, 2015, Exelon had regulatory assets of $3,156 million and regulatory liabilities of $94 million related to ComEd s and BGE s portion of deferred costs associated with Exelon s pension plans and ComEd s, PECO s and BGE s portion of

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

deferred costs associated with Exelon s other postretirement benefit plans. PECO s pension regulatory recovery is based on cash contributions and is not included in the regulatory asset (liability) balances. The regulatory asset (liability) is amortized in proportion to the recognition of prior service costs (gains), transition obligations and actuarial losses (gains) attributable to Exelon s pension and other postretirement benefit plans determined by the cost recognition provisions of the authoritative guidance for pensions and postretirement benefits. ComEd, PECO and BGE will recover these costs through base rates as allowed in their most recently approved regulated rate orders. The pension and other postretirement benefit regulatory asset balance includes a regulatory asset established at the date of the Constellation merger related to BGE s portion of the deferred costs associated with legacy Constellation s pension and other postretirement benefit plans. The BGE-related regulatory asset is being amortized over a period of approximately 12 years, which generally represents the expected average remaining service period of plan participants at the date of the Constellation merger. See Note 17 Retirement Benefits for additional detail. No return is earned on Exelon s regulatory asset.

Deferred income taxes. These costs represent the difference between the method by which the regulator allows for the recovery of income taxes and how income taxes would be recorded under GAAP. Regulatory assets and liabilities associated with deferred income taxes, recorded in compliance with the authoritative guidance for accounting for certain types of regulation and income taxes, include the deferred tax effects associated principally with accelerated depreciation accounted for in accordance with the ratemaking policies of the ICC, PAPUC and MDPSC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future transmission and distribution rates. For BGE, this amount includes the impacts of a reduction in the deductibility, for Federal income tax purposes, of certain retiree health care costs pursuant to the March 2010 Health Care Reform Acts. For BGE, these additional income taxes are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC s March 2011 rate order. For PECO, this amount includes the impacts of electric and gas distribution repairs in the deductibility pursuant to PUC s 2010 and 2015 rate case settlement agreements. See Note 15 Income Taxes and Note 17 Retirement Benefits for additional information. ComEd, PECO and BGE are not earning a return on the regulatory asset in base rates.

AMI programs. For ComEd, this amount represents meter costs associated with ComEd s AMI pilot program approved in ComEd s 2010 rate case. The recovery periods for the meter costs are through January 1, 2020. As of December 31, 2015 and December 31, 2014, ComEd had regulatory assets of $137 million and $88 million, respectively, related to accelerated depreciation costs resulting from the early retirements of non-AMI meters, which will be amortized over an average ten year period pursuant to the ICC approved AMI Deployment plan. ComEd is earning a return on the regulatory asset. For PECO, this amount represents accelerated depreciation and filing and implementation costs relating to the PAPUC-approved Smart Meter Procurement and Installation Plan as well as the return on the un-depreciated investment, taxes, and operating and maintenance expenses. The approved plan allows for recovery of filing and implementation costs incurred through December 31, 2012. In addition, the approved plan provides for recovery of program costs, which includes depreciation on new equipment placed in service, beginning in January 2011 on full and current basis, which includes interest income or expense on the under or over recovery. The approved plan also provides for recovery of accelerated depreciation on PECO s non-AMI meter assets over a 10-year period ending December 31, 2020. Recovery of smart meter costs will be reflected in base rates effective January 1, 2016. For BGE, this amount represents smart grid pilot program costs as well as the incremental costs associated with implementing full deployment of a smart grid program. Pursuant to a MDPSC order, pilot program costs of $11 million were deferred in a regulatory asset, and, beginning with the MDPSC s March 2011 rate order, is earning BGE s most current authorized rate of return. In August

Combined Notes to Consolidated Financial Statements (Continued)

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

2010, the MDPSC approved a comprehensive smart grid initiative for BGE, authorizing BGE to establish a separate regulatory asset for incremental costs incurred to implement the initiative, including the net depreciation and amortization costs associated with the meters, and an appropriate rate of return on these costs, a portion of which is not recognized under GAAP until cost recovery begins. Additionally, the MDPSC requires that BGE prove the cost-effectiveness of the entire smart grid initiative prior to seeking recovery of the costs deferred in these regulatory assets. As part of the 2015 electric and gas distribution rate case filed on November 6, 2015 and amended on January 5, 2016, BGE is seeking recovery of its smart grid initiative costs. Of BGE s requested \$200 million, \$140 million relates to the smart grid initiative. In support of its recovery of smart grid initiative costs, BGE provided evidence demonstrating that the benefits exceed the costs by a ratio of 2.3 to 1.0, on a nominal basis. If approved by the MDPSC, the amortization of these deferred costs would begin in June 2016. BGE s AMI regulatory asset excludes costs for non-AMI meters being replaced by AMI meters, as recovery of those costs commenced with the new rates approved and implemented with the MDPSC order in BGE s 2014 electric and gas distribution case.

Under-recovered distribution services costs. These amounts represent under (over) recoveries related to electric distribution services costs recoverable (refundable) through EIMA s performance based formula rate tariff. Under (over) recoveries for the annual reconciliations are recoverable (refundable) over a one-year period and costs for certain one-time events, such as large storms, are recoverable over a five-year period. ComEd earns and pays a return on under and over recovered costs, respectively. As of December 31, 2015, the regulatory asset was comprised of \$142 million for the 2014 and 2015 annual reconciliations and \$47 million related to significant one-time events, including \$36 million in deferred storm costs and \$11 million of Constellation merger and integration related costs. As of December 31, 2014, the regulatory asset was comprised of \$286 million for the 2013 and 2014 annual reconciliations and \$85 million related to significant one-time events, including \$66 million in deferred storm costs and \$19 million of Constellation merger and integration related costs. See *Energy Infrastructure Modernization Act* above for further details.

Debt costs. Consistent with rate recovery for ratemaking purposes, ComEd s, PECO s and BGE s recoverable losses on reacquired long-term debt related to regulated operations are deferred and amortized to interest expense over the life of the new debt issued to finance the debt redemption or over the life of the original debt issuance if the debt is not refinanced. Interest-rate swap settlements are deferred and amortized over the period that the related debt is outstanding or the life of the original issuance retired. These debt costs are used in the determination of the weighted cost of capital applied to rate base in the rate-making process. ComEd and BGE are not earning a return on the recovery of these costs, while PECO is earning a return on the premium of the cost of the reacquired debt through base rates.

Fair value of BGE long-term debt. These amounts represent the regulatory asset recorded at Exelon for the difference in the fair value of the long-term debt of BGE as of the Constellation merger date based on the MDPSC practice to allow BGE to recover its debt costs through rates. Exelon is amortizing the regulatory asset and the associated fair value over the life of the underlying debt and is not earning a return on the recovery of these costs.

Severance. For BGE, these costs represent deferred severance costs associated with a 2010 workforce reduction that were deferred as a regulatory asset and are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC s March 2011 rate order. Additionally, costs associated with the 2012 BGE voluntary workforce reduction were deferred in 2012 as a regulatory asset in accordance with the MDPSC s orders in prior rate cases and are being amortized over a 5-year period that began in July 2012. BGE is earning a regulated return on the regulatory asset included in base rates.

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

Asset retirement obligations. These costs represent future legally required removal costs associated with existing asset retirement obligations. PECO will begin to earn a return on, and a recovery of, these costs once the removal activities have been performed. ComEd and BGE will recover these costs through future depreciation rates and will earn a return on these costs once the removal activities have been performed. See Note 16 Asset Retirement Obligations for additional information.

MGP remediation costs. ComEd is allowed recovery of these costs under ICC approved rates. For PECO, these costs are recoverable through rates as affirmed in the 2010 approved natural gas distribution rate case settlement. The period of recovery for both ComEd and PECO will depend on the timing of the actual expenditures. ComEd and PECO are not earning a return on the recovery of these costs. 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. For BGE, $5 million of clean-up costs incurred during the period from July 2000 through November 2005 and an additional $1 million from December 2005 through November 2010 are recoverable through rates in accordance with MDPSC orders. BGE is earning a return on this regulatory asset and these costs are being amortized over 10-year periods that began in January 2006 and December 2010, respectively. The recovery period for the 10-year period that began January 2006 was extended for an additional 24 months, in accordance with the MDPSC approved 2014 electric and natural gas distribution rate case order. See Note 23 Commitments and Contingencies for additional information.

Under recovered uncollectible accounts. These amounts represent the difference between ComEd s annual uncollectible accounts expense and revenues collected in rates through an ICC-approved rider. The difference between net uncollectible account charge-offs and revenues collected through the rider each calendar year is recovered or refunded over a twelve-month period beginning in June of the following calendar year. ComEd does not earn a return on these under recoveries.

Renewable energy. In December 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy. Delivery under the contracts began in June 2012. Since the swap contracts were deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period as well as an offsetting regulatory asset or liability are recorded by ComEd. ComEd does not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd s cost to purchase energy at the market price and the contracted price.

Energy and transmission programs. These amounts represent under (over) recoveries related to energy and transmission costs recoverable (refundable) under ComEd s ICC and/or FERC-approved rates. Under (over) recoveries are recoverable (refundable) over a one-year period or less. ComEd earns a return or interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2015, ComEd s regulatory asset of $43 million included $5 million related to under-recovered energy costs, $31 million associated with transmission costs recoverable through its FERC-approved formula rate tariff, and $7 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2015, ComEd s regulatory liability of $53 million included $29 million related to over-recovered energy costs and $24 million associated with revenues received for renewable energy requirements. As of December 31, 2014, ComEd s regulatory asset of $33 million included $4 million related to under-recovered energy costs, $22 million associated with transmission costs recoverable through its FERC-approved formula rate tariff, and $7 million of

Combined Notes to Consolidated Financial Statements (Continued)

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

Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2014, ComEd s regulatory liability of $19 million included $3 million related to over-recovered energy costs and $16 million associated with revenues received for renewable energy requirements. See *Transmission Formula Rate* above for further details.

The PECO energy costs represent the electric and gas supply related costs recoverable (refundable) under PECO s GSA and PGC, respectively. PECO earns interest on the under-recovered energy and natural gas costs and pays interest on over-recovered energy and natural gas costs to customers. In addition, the DSP Program costs are presented on a net basis with PECO s GSA under (over)-recovered energy costs. See additional discussion below. The PECO transmission costs represent the electric transmission costs recoverable (refundable) under the TSC under which PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2015, PECO had a regulatory liability that included $35 million related to the DSP program, $22 million related to over-recovered natural gas supply costs under the PGC and $3 million related to over-recovered electric transmission costs. As of December 31, 2014, PECO had a regulatory liability that included $39 million related to the DSP program, $3 million related the over-recovered electric transmission costs and $16 million related to over-recovered natural gas supply costs under the PGC.

DSP Program Costs. These amounts represent recoverable administrative costs incurred relating to the filing and procurement associated with PECO s PAPUC-approved DSP programs for the procurement of electric supply. The filings and procurements of these DSP Programs are recoverable through the GSA over each respective term. The original DSP Program had a 29-month term that began January 1, 2011. DSP II and DSP III each have a 24-month term that began June 1, 2013 and June 1, 2015, respectively. The independent evaluator costs associated with conducting procurements are recoverable over a 12-month period after the PAPUC approves the results of the procurements. PECO is not earning a return on these costs. Certain costs included in PECO s original DSP program related to information technology improvements were recovered over a 5-year period that began January 1, 2011. PECO earns a return on the recovery of information technology costs. These costs are included within the energy and transmission programs line item.

The BGE energy costs represent the electric supply, gas supply, and transmission related costs recoverable (refundable) from (to) customers under BGE s market-based SOS program, MBR program, and FERC approved transmission rates, respectively. BGE does not earn or pay interest on under- or over-recovered costs to customers. As of December 31, 2015, BGE s regulatory asset of $40 million included $12 million associated with transmission costs recoverable through its FERC approved formula rate and $28 million related to under-recovered electric energy costs. As of December 31, 2015, BGE s regulatory liability of $18 million related to $5 million of over-recovered natural gas costs $14 million of over-recovered transmission costs, offset by $1 million of abandonment costs to be recovered upon FERC approval. As of December 31, 2014, BGE s regulatory asset of $15 million included $10 million related to under-recovered electric energy costs, $4 million of Constellation merger and integration costs and $1 million of transmission costs recoverable through its FERC approved formula rate. As of December 31, 2014, BGE s regulatory liability of $7 million related to over-recovered natural gas supply costs.

Deferred storm costs. In the MDPSC s March 2011 rate order, BGE was authorized to defer $16 million in storm costs incurred in February 2010. BGE earns a return on this regulatory asset and the recovery period was extended for an additional 25 months, in accordance with the MDPSC approved 2014 electric and natural gas distribution rate case order.

Combined Notes to Consolidated Financial Statements (Continued)

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

Electric generation-related regulatory asset. As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities and established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules. The portion of this regulatory asset that does not earn a regulated rate of return was $19 million as of December 31, 2015, and $28 million as of December 31, 2014. BGE will continue to amortize this amount through 2017.

Rate stabilization deferral. In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006, to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006 to May 31, 2007. In addition, as required by Senate Bill 1, the MDPSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007 to January 1, 2008. During 2007, BGE deferred $306 million of electricity purchased for resale expenses and certain applicable carrying charges, which are calculated using the implied interest rates of the rate stabilization bonds, as a regulatory asset related to the rate stabilization plans. During 2015 and 2014, BGE recovered $73 million and $65 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007.

Energy efficiency and demand response programs. For ComEd, these amounts represent over recoveries related to ComEd s ICC-approved Energy Efficiency and Demand Response Plan. ComEd refunds these over recoveries through a rider over a twelve-month period. ComEd earns a return on the capital investment incurred under the program, but does not earn or pay interest on under or over recoveries, respectively. For PECO, these amounts represent over recoveries of program costs related to both Phase I and Phase II of its PAPUC-approved EE&C Plan. PECO began recovering the costs of its Phase I and Phase II EE&C Plans through a surcharge in January 2010 and June 2013, respectively, based on projected spending under the programs. Phase I recovery continued over the life of the program, which expired on May 31, 2013 and excess funds collected began being refunded in June 2013. Phase II of the program began on June 1, 2013, and will continue over the life of the program, which will expire on May 31, 2016. Excess funds collected are required to be refunded beginning in June 2016. PECO earned a return on the capital investment incurred under Phase I of the program. PECO does not earn (pay) interest on under (over) collections. For BGE, these amounts represent under (over) recoveries related to BGE s Smart Energy Savers Program®, which includes both MDPSC-approved demand response and energy efficiency programs. For the BGE Peak Rewards℠ demand response program which began in January 2008, actual marketing and customer bonus costs incurred in the demand response program are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the MDPSC. Fixed assets related to the demand response program are recovered over the life of the equipment. Also included in the demand response program are customer bill credits related to BGE s Smart Energy Rewards program which began in July 2013 and are being recovered through the surcharge. Actual costs incurred in the energy efficiency program are being amortized over a 5-year period with recovery beginning in 2010 pursuant to an order by the MDPSC. BGE earns a rate of return on the capital investments and deferred costs incurred under the program and earns (pays) interest on under (over) collections.

Combined Notes to Consolidated Financial Statements (Continued)

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

Merger integration costs. These amounts represent integration costs to achieve distribution synergies related to the Constellation merger transaction. As a result of the MDPSC s February 2013 rate order, BGE deferred $8 million related to non-severance merger integration costs incurred during 2012 and the first quarter of 2013. Of these costs, $4 million was authorized to be amortized over a 5-year period that began in March 2013. The recovery of the remaining $4 million was deferred. In the MDPSC s December 2013 rate order, BGE was authorized to recover the remaining $4 million and an additional $4 million of non-severance merger integration costs incurred during 2013. These costs are being amortized over a 5-year period that began in December 2013. BGE is earning a return on this regulatory asset included in base rates.

Under (Over)-recovered electric and gas revenue decoupling. These amounts represent the electric and gas distribution costs recoverable from or (refundable) to customers under BGE s decoupling mechanism, which does not earn a rate of return. As of December 31, 2015, BGE had a regulatory asset of $30 million related to under-recovered electric revenue decoupling and a regulatory liability of $1 million related to over-recovered natural gas revenue decoupling. As of December 31, 2014, BGE had a regulatory asset of $7 million related to under-recovered electric revenue decoupling and a regulatory liability of $12 million related to over-recovered natural gas revenue decoupling.

CAP arrearage. These amounts represent the guaranteed recovery of previously incurred bad debt expense associated with the estimated eligible CAP accounts receivable balances under the IPAF Program as provided by the 2015 electric distribution rate case settlement. These costs are amortized as recovery is received through a combination of customer payments and rate recovery, including through future rate cases if necessary. PECO is not earning a return on this regulatory asset.

Nuclear decommissioning. These amounts represent estimated future nuclear decommissioning costs for the Regulatory Agreement Units that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. Exelon believes the trust fund assets, including prospective earnings thereon and any future collections from customers, will be sufficient to fund the associated future decommissioning costs at the time of decommissioning. Exelon is not accruing interest on these costs. See Note 16 Asset Retirement Obligations for additional information.

Removal costs. These amounts represent funds ComEd and BGE have received from customers through depreciation rates to cover the future non-legally required cost of removal of property, plant and equipment which reduces rate base for ratemaking purposes. This liability is reduced as costs are incurred.

DLC program costs. The DLC program costs include equipment, installation, and information technology costs necessary to implement the DLC Program under PECO s EE&C Phase I Plans. PECO received full cost recovery through Phase I collections and will amortize the costs as a credit to the income statement to offset the related depreciation expense during the same period through September 2025, which is the remaining useful life of the assets. PECO is not paying interest on these over-recovered costs.

Electric distribution tax repairs. PECO s 2010 electric distribution rate case settlement required that the expected cash benefit from the application of Revenue Procedure 2011-43, which was issued on August 19, 2011, to prior tax years be refunded to customers over a seven-year period. Credits began being reflected in customer bills on January 1, 2012. PECO s 2015 electric distribution rate case settlement requires PECO to pay interest on the unamortized balance of the tax-effected catch-up deduction beginning January 1, 2016.

Combined Notes to Consolidated Financial Statements (Continued)

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

Gas distribution tax repairs. PECO s 2010 natural gas distribution rate case settlement required that the expected cash benefit from the application of new tax repairs deduction methodologies for 2010 and prior tax years be refunded to customers over a seven-year period. In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. Credits began being reflected in customer bills on January 1, 2013. No interest will be paid to customers.

Revenue subject to refund. These amounts represent refunds and associated interest ComEd owes to customers primarily related to the treatment of the post-test year accumulated depreciation issue in the 2007 Rate Case. As of December 31, 2015, and December 31, 2014, ComEd owed $0 million and $3 million, respectively.

Purchase of Receivables Programs (Exelon, ComEd, PECO, and BGE)

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities consolidated billing, ComEd, PECO and BGE must purchase their customer accounts receivables. ComEd and BGE purchase receivables at a discount to primarily recover uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and is permitted to recover uncollectible accounts expense from customers through distribution rates. Exelon, ComEd, PECO, and BGE do not record unbilled commodity receivables under their POR programs. Purchased billed receivables are classified in other accounts receivable, net on Exelon s, ComEd s, PECO s and BGE s Consolidated Balance Sheets. The following tables provide information about the purchased receivables of the Registrants as of December 31, 2015 and 2014.

As of December 31, 2015	**Exelon**	**ComEd**	**PECO**	**BGE**
Purchased receivables [(a)]	$ 229	$ 103	$ 67	$ 59
Allowance for uncollectible accounts [(b)]	(31)	(16)	(7)	(8)
Purchased receivables, net	$ 198	$ 87	$ 60	$ 51

As of December 31, 2014	**Exelon**	**ComEd**	**PECO**	**BGE**
Purchased receivables [(a)]	$ 290	$ 139	$ 76	$ 75
Allowance for uncollectible accounts [(b)]	(42)	(21)	(8)	(13)
Purchased receivables, net	$ 248	$ 118	$ 68	$ 62

(a) PECO s gas POR program became effective on January 1, 2012 and includes a 1% discount on purchased receivables in order to recover the implementation costs of the program. The implementation costs were fully recovered and the 1% discount was reset to 0%, effective July 2015.
(b) For ComEd and BGE, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing (PORCB) tariff.

4. Mergers, Acquisitions, and Dispositions (Exelon and Generation)

Proposed Merger with Pepco Holdings, Inc. (Exelon)

Description of Transaction

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

Combined Notes to Consolidated Financial Statements (Continued)

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

combine the two companies in an all cash transaction. The resulting company will retain the Exelon name. Under the Merger Agreement, PHI s shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. Based on the outstanding shares of PHI s common stock as of December 31, 2015, PHI shareholders would receive $6.9 billion in total cash. In addition, in connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased $180 million of a class of nonvoting, nonconvertible and nontransferable preferred securities of PHI. The preferred securities are included in Other non-current assets on Exelon s Consolidated Balance Sheet. PHI has the right to redeem the preferred securities at its option for the purchase price paid plus accrued dividends, if any.

On November 2, 2015, Exelon and PHI each filed a new Notification and Report Form with the DOJ under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act) due to the expiration of the original filing. The HSR Act waiting period expired on December 2, 2015, and the HSR Act no longer precludes completion of the merger.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBPU), the Delaware Public Service Commission (DPSC), the Maryland Public Service Commission (MDPSC) 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. The March 6, 2015, order by the NJBPU approving the merger required that the consummation of the merger must take place no later than November 1, 2015 unless otherwise extended by the Board. On October 15, 2015, the NJBPU extended the November 1, 2015 date to June 30, 2016.

On February 13, 2015, Exelon and PHI announced that they had reached a settlement agreement in the proceeding before the DPSC to review the proposed merger. The settlement, which was amended on April 7, 2015, was signed and filed by Exelon, PHI, Delmarva Power & Light Company (DPL), the DPSC Staff, the Delaware Public Advocate, the Delaware Department of Natural Resources and Environmental Control, the Delaware Sustainable Energy Utility, the Mid-Atlantic Renewable Energy Coalition and the Clean Air Council. As part of this settlement, Exelon and PHI proposed a package of benefits to DPL customers and the state of Delaware including the establishment of customer rate credits of $40 million for DPL customers in Delaware, $2 million of funding for energy efficiency programs for DPL low income customers, and $2 million of funding for workforce development. On June 2, 2015, the DPSC issued an order accepting the settlement and approving the merger between Exelon and PHI.

On March 17, 2015, Exelon and PHI announced that they had reached settlements with multiple parties in the Maryland proceeding to review the proposed merger after filing a Request for Adoption of Settlements with the MDPSC. The settlements were signed and filed by Exelon, PHI, Montgomery County, Prince George s County, the National Consumer Law Center, National Housing Trust, the Maryland Affordable Housing Coalition, the Housing Association of Nonprofit Developers, and a consortium of recreational trail advocacy organizations led by the Mid-Atlantic Off-Road Enthusiasts.

Combined Notes to Consolidated Financial Statements (Continued)

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

Exelon and PHI also announced a settlement with The Alliance for Solar Choice. On May 15, 2015, the MDPSC approved the merger after modifying a number of the conditions in the settlements, resulting in total rate credits of $66 million, funding for energy efficiency programs of $43.2 million, a Green Sustainability Fund of $14.4 million, 20 MWs of renewable generation development and increased penalties related to reliability commitments. On May 18, 2015, Exelon and PHI accepted and committed to fulfill the conditions.

On June 11, 2015, the Maryland Office of People s Counsel (OPC), the Sierra Club, and the Chesapeake Climate Action Network filed Petitions for Judicial Review of the MDPSC s approval of the merger with the Circuit Court for Queen Anne s County. On June 23, 2015, Public Citizen, Inc. filed its Petition for Judicial Review with the Circuit Court for Queen Anne s County. On July 10, 2015, Exelon and PHI filed a response in opposition to the Petitions for Review.

On July 21, 2015, the OPC filed a motion to stay the MDPSC order approving the merger and to set a schedule for discovery and presentation of new evidence. On July 29, 2015, Public Citizen, Inc. filed a response supporting OPC s motion to stay, and on July 31, 2015 the Sierra Club and the Chesapeake Climate Action Network filed a joint motion to stay. In July and August, Exelon, PHI, the MDPSC, Prince George s County and Montgomery County filed responses opposing the motions to stay. The judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the Circuit Court judge affirmed the MDPSC s order approving the merger and denied the petitions for judicial review filed by the OPC, the Sierra Club, the Chesapeake Climate Action Network (CCAN) and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special appeals, and on January 21, Sierra Club and CCAN filed a notice of appeal. In the ordinary course this appeal would be resolved no earlier than third quarter 2016.

On August 27, 2015, the District of Columbia Public Service Commission (DCPSC) issued an Opinion and Order denying approval of the merger, concluding that the merger as presented was not in the public interest. Exelon and PHI filed an Application for Reconsideration with the DCPSC on September 28, 2015. On October 6, 2015, Exelon, PHI, the District of Columbia Government, the Office of Peoples Counsel, the District of Columbia Water and Sewer Authority, the National Consumer Law Center, National Housing Trust and National Housing Trust Enterprise Preservation Corporation, and the Apartment and Office Building Association of Metropolitan Washington (collectively, Settling Parties) entered into a Nonunanimous Full Settlement Agreement and Stipulation (Settlement Agreement) with respect to the merger. Exelon and PHI subsequently filed a motion of joint applicants requesting the DCPSC to reopen the approval application to allow for consideration of the Settlement Agreement and granting additional requested relief. The new package of benefits totals $78 million and includes commitments to provide relief of residential customer base rate increases of $26 million, one-time direct bill credits of $14 million, low-income energy assistance of $16 million, improved reliability, a cleaner and greener D.C. through funding energy efficiency programs and development of renewable energy, and investment in local jobs and the local economy through workforce development of $5 million. It also guarantees charitable contributions totaling $19 million over 10 years.

On October 28, 2015, the DCPSC agreed to reopen the approval application to allow for consideration of the Settlement Agreement. Since then, parties supporting and opposing the Settlement filed testimony, participated in formal hearings and, on December 23, 2015, submitted final briefs to the DCPSC. The parties now await a formal decision from the DCPSC. The Merger Agreement provides that either Exelon or PHI may terminate the Merger Agreement if the merger is not completed by October 28, 2015. Pursuant to a Letter Agreement related to the Settlement Agreement, Exelon and PHI have agreed, among other things, that they will not exercise their rights to terminate

Combined Notes to Consolidated Financial Statements (Continued)

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

the Merger Agreement before March 4, 2016, except under limited circumstances. If the DCPSC does not approve the Settlement Agreement by March 4, 2016, either Exelon or PHI may terminate the Settlement Agreement.

The settlements reached and commission orders received to date in Delaware, Maryland and New Jersey include a most favored nation provision which, generally speaking, requires allocation of merger benefits proportionately across all the jurisdictions. When applying the most favored nation provision to the settlement terms and other conditions established in the merger approvals received to date, and as proposed in the Settlement Agreement filed with the DCPSC, Exelon and PHI currently estimate direct benefits of $430 million or more on a net present value basis (excluding charitable contributions and renewable generation commitments) will be provided, including rate credits, funding for energy efficiency programs and other required commitments. Exelon and PHI anticipate substantially all of such amounts will be charged to earnings at the time of merger close and will be paid by the end of 2017. An additional $53 million will be charged to earnings at the time of the merger close for charitable contributions, which are then required to be paid over a period of 10 years. Commitments to develop renewable generation, which are expected to be primarily capital in nature, will be recognized as incurred. Upon completion of the merger, the actual nature, amount, timing and financial reporting treatment for these commitments may be materially different from the current projection.

Exelon has been named in suits filed in the Delaware Chancery Court alleging that individual directors of PHI breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors breaches. The suits seek to enjoin PHI from completing the merger or seek rescission of the merger if completed. In addition, they also seek unspecified damages and costs. Exelon was also named in a federal court suit making similar claims. In September 2014, the parties reached a proposed settlement that would resolve all claims, which is subject to court approval. Final court approval of the proposed settlement is not anticipated until approximately 90 days after merger close. Exelon does not believe these suits will impact the completion of the transaction, and they are not expected to have a material impact on Exelon s results of operations.

Including 2014 and through December 31, 2015, Exelon has incurred approximately $259 million of expense associated with the proposed merger. Of the total costs incurred, $121 million is primarily related to acquisition and integration costs and $138 million are for costs incurred to finance the transaction. The financing costs include $22 million of costs associated with the private exchange offer and redemption of certain Senior Unsecured Notes (see Note 14 Debt and Credit Agreements for further information on the exchange), as well as, a net loss of $64 million related to the settlement of forward-starting interest-rate swaps. These swaps were terminated in connection with the $4.2 billion issuance of debt; refer to Note 13 Derivative Financial Instruments for more information. The financing costs exclude costs to issue equity and the initial debt offering which we recorded to Exelon s Consolidated Balance Sheets.

	For the year ended,	
Acquisition, Integration and Financing Costs [(a)]	**2015**	**2014**
Exelon	$ 80	$ 179
Generation	25	11
ComEd	10	4
PECO	5	2
BGE	5	2

Combined Notes to Consolidated Financial Statements (Continued)

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

(a) The costs incurred are classified primarily within Operating and maintenance expense in the Registrants respective Consolidated Statement of Operations and Comprehensive Income, with the exception of the financing costs, which are included within Interest expense.

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 Merger Agreement is terminated due to a failure to obtain a required regulatory approval, Exelon may be required to pay PHI a termination fee equal to $180 million through the redemption by PHI of the outstanding nonvoting preferred securities described above for no consideration other than the nominal par value of the stock, plus reimbursement of PHI s documented out-of-pocket expenses up to a maximum of $40 million.

Merger Financing

Exelon has raised cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments, through the issuance of $4.2 billion of debt (of which $3.3 billion remains after execution of the exchange offer, see Note 14 Debt and Credit Agreements for further information on the exchange), $1.15 billion of junior subordinated notes in the form of 23 million equity units, the issuance of $1.9 billion of common stock, cash proceeds of $1.8 billion from asset sales primarily at Generation (after-tax proceeds of approximately $1.4 billion) and the remaining balance from cash on hand and/or short-term borrowings available to Exelon. Exelon will have sufficient cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments. See Note 14 Debt and Credit Agreements and Note 19 Shareholder s Equity for further information on the debt and equity issuances.

Acquisitions (Exelon and Generation)

Acquisition of Integrys Energy Services, Inc. (Exelon and Generation)

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. (IES) for a purchase price of $332 million, including net working capital. Generation has elected to account for the transaction as an asset acquisition for federal income tax purposes. The generation and solar asset businesses of Integrys are excluded from the transaction. The Purchase Agreement also includes various representations, warranties, covenants, indemnification and other provisions customary for a transaction of this nature.

Consistent with the applicable accounting guidance, the fair value of the assets acquired and liabilities assumed was determined as of the acquisition date through the use of significant estimates and assumptions that are judgmental in nature. Some of the more significant estimates and assumptions used include: projected future cash flows (including the amount and timing); discount rates reflecting the risk inherent in the future cash flows; and future power and fuel market prices.

Combined Notes to Consolidated Financial Statements (Continued)

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

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the Integrys acquisition by Generation:

Total consideration transferred	$ 332
Identifiable assets acquired and liabilities assumed	
Working capital assets	$ 390
Mark-to-market derivative assets	184
Unamortized energy contract assets	115
Customer relationships	50
Working capital liabilities	(196)
Mark-to-market derivative liabilities	(57)
Unamortized energy contract liabilities	(110)
Deferred tax liability	(16)
Total net identifiable assets, at fair value	$ 360
Bargain purchase gain (after-tax)	$ 28

The after-tax bargain purchase gain of $28 million is primarily the result of IES executing additional contract volumes between the date the acquisition agreement was signed and the closing of the transaction resulting in an increase in the fair value of the net assets acquired as of the acquisition date. The after-tax gain is included within Gain on consolidation and acquisition of businesses in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

IES s operating revenues and net loss included in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income for the period from November 1, 2014 to December 31, 2014 were $386 million and $(42) million, respectively. The net loss for the period from November 1, 2014 to December 31, 2014 includes pre-tax unrealized losses on derivative contracts of $108 million and the bargain purchase gain of $28 million. It is impracticable to determine the overall financial statement impact of IES for 2015 due to the integration of the business into ongoing operations. For the years ended December 31, 2015 and 2014, Exelon and Generation incurred $5 million and $7 million, respectively, of merger and integration related costs which are included within Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

Asset Divestitures (Exelon and Generation)

Including the Quail Run generating facility that was sold on January 21, 2015, Generation has sold certain generating assets with a total net book value of approximately $1.8 billion prior to consideration of asset impairments (See Note 8 Impairment of Long-Lived Assets for further information), for total pre-tax proceeds of approximately $1.8 billion (after-tax proceeds of approximately $1.4 billion), which resulted in cumulative pre-tax gains on sale of approximately $412 million, which are included in Gain (loss) on sales of assets on Exelon s and Generation s Consolidated Statement of Operations and Comprehensive Income for the year ended December 31, 2014. The proceeds are expected to be used primarily to finance a portion of the merger with PHI.

Station	Net Generation Capacity	Location	Operating Segment	Percent Owned
Fore River	726 MW	North Weymouth, MA	New England	100%
West Valley	185 MW	Salt Lake City, UT	Other	100%
Keystone	714 MW	Shelocta, PA	Mid-Atlantic	41.98%
Conemaugh	532 MW	New Florence, PA	Mid-Atlantic	31.28%
Safe Harbor	278 MW	Conestoga, PA	Mid-Atlantic	66.7%
Quail Run	488 MW	Odessa, TX	ERCOT	100%

At December 31, 2014, the assets and liabilities of the Quail Run generating facility were reported as Assets held for sale and within Other current liabilities on Exelon s and Generation s Consolidated Balance Sheets. The table below presents the major classes of assets and liabilities held for sale at December 31, 2014. Assets held for sale at December 31, 2015 are not material.

	December 31, 2014
Assets	
Property, plant and equipment, net (a)	$ 143
Inventory	4
Total assets held for sale	$ 147
Liabilities	
Accrued expenses	$ 1
Asset retirement obligations	4
Total liabilities held for sale (b)	$ 5

(a) The total aggregate book value of property, plant and equipment is net of a $50 million pre-tax impairment loss recorded within Operating and maintenance expense on Exelon s and Generation s Statements of Operations and Comprehensive Income for the year ended December 31, 2014. See Note 8 Impairment of Long-Lived Assets for further information.

(b) Included within Other current liabilities on Exelon s and Generation s Consolidated Balance Sheets.

5. Investment in Constellation Energy Nuclear Group, LLC (Exelon and Generation)

Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation has historically had various agreements with CENG to purchase power and to provide certain services. For further information regarding these agreements, see Note 26 Related Party Transactions.

On April 1, 2014, Generation and subsidiaries of Generation and CENG entered into a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for

Combined Notes to Consolidated Financial Statements (Continued)

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

the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDF s rights as a member of CENG (the Integration Transaction). CENG will reimburse Generation for its direct and allocated costs for such services. As part of the arrangement, Nine Mile Point Nuclear Station, LLC, a subsidiary of CENG, also assigned to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with Long Island Power Authority, the Unit 2 co-owner. In addition, on April 1, 2014, the Power Services Agency Agreement (PSAA) was amended and extended until the permanent cessation of power generation by the CENG generation plants.

In addition, on April 1, 2014, Generation made a $400 million loan to CENG, bearing interest at 5.25% per annum and payable out of specified available cash flows of CENG or payable upon the maturity date of April 1, 2034. Immediately following receipt of the proceeds of such loan, CENG made a $400 million special distribution to EDF. Unpaid principal and accrued interest on the loan was $300 million as of December 31, 2015.

Exelon, Generation, and subsidiaries of Generation, EDF and CENG also executed a Fourth Amended and Restated Operating Agreement for CENG on April 1, 2014, pursuant to which, among other things, CENG committed to make preferred distributions to Generation (after repayment of the $400 million loan and associated interest) quarterly out of specified available cash flows until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from April 1, 2014 (Preferred Distribution Rights).

Generation and EDF also entered into a Put Option Agreement on April 1, 2014, pursuant to which EDF has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. The appraisers determining fair market value of EDF s 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation s rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation s rights to other distributions. Under limited circumstances, the period for exercise of the put option may be extended for 18 months. In order to exercise its option, EDF must give 60 days advance written notice to Generation stating that it is exercising its option. As of the date these financial statements were issued, EDF has not given notice to Generation that it is exercising its option.

On April 1, 2014, Generation also executed an Indemnity Agreement pursuant to which Generation indemnified EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation s obligations under this indemnity.

In addition, on April 1, 2014, Generation, EDF, CENG and Nine Mile Point Nuclear Station, LLC entered into an Employee Matters Agreement (EMA) that provides for the transfer of CENG employees to Exelon or one of its affiliates and Exelon s assumption of the sponsorship of the employee benefit plans (including certain incentive, health and welfare, and postemployment benefit plans, among others) and their related trusts by Exelon as the plan sponsor as of July 14, 2014. The EMA also generally requires CENG to fund the obligation related to pre-transfer service of employees, including the underfunded balance of the pension and other postretirement welfare benefit plans measured as of July 14, 2014 by making periodic payments to Generation. These payments will be made on an agreed

Combined Notes to Consolidated Financial Statements (Continued)

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

payment schedule or upon the occurrence of certain specified events, such as EDF s disposition of a majority of its interest in CENG. However, in the event that EDF exercises its rights under the Put Option, all payments not made as of the put closing date shall accelerate to be paid immediately prior to such closing date.

As a condition to obtaining regulatory approval for the NOSA and related transactions from the NRC, Exelon executed a support agreement pursuant to which Exelon may be required under specified circumstances to provide up to $245 million of financial support to CENG (Exelon Support Agreement). The Exelon Support Agreement supersedes a previous support agreement under which Generation had agreed to provide up to $205 million of financial support for CENG. In addition, Exelon executed a Guarantee pursuant to which Exelon may be required under specified circumstances to provide up to $165 million in additional financial support for CENG. A previous support agreement executed by an affiliate of EDF remains in effect under which the EDF affiliate may be required to provide up to approximately $145 million of financial support for CENG under specified circumstances. The agreements were executed on April 1, 2014 when the NRC licenses were transferred to Generation. No liability has been recognized by Exelon for the guarantees.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. From January 1, 2014, through March 31, 2014, Generation recorded $19 million of equity in losses of unconsolidated affiliates related to its investment in CENG and recorded $17 million of revenues from CENG. For the twelve months ended December 31, 2013, Generation recorded $9 million of equity in losses of unconsolidated affiliates related to its investment in CENG and $56 million of revenues from CENG. The book value of Generation s investment in CENG prior to the consolidation was $1.9 billion, and the book value of the AOCI related to CENG prior to consolidation was $116 million, net of taxes of $77 million.

As a result of the consolidation of CENG on April 1, 2014, there are several additional transactions included in Exelon s and Generation s Consolidated Financial Statements between CENG and Exelon s affiliates that are considered related party transactions to Generation. As further described in Note 26 Related Party Transactions, EDF and Generation had a PPA with CENG under which they purchased 15% and 85%, respectively, of the nuclear output owned by CENG that was not sold to third parties under pre-existing PPAs through December 31, 2014. Beginning January 1, 2015 and continuing through the life of the respective plants, EDF and Generation purchase 49.99% and 50.01%, respectively, of the nuclear output owned by CENG not subject to other contractual agreements. Beginning April 1, 2014, CENG s sales to Generation have been eliminated in consolidation. For the years ended December 31, 2015 and 2014, Generation had sales to EDF of $488 million and $137 million, respectively. See discussion above and Note 2 Variable Interest Entities for additional information regarding other transactions between CENG and EDF included within Exelon and Generation s consolidated financial statements and for additional information about the Registrants VIE s.

Accounting for the Consolidation of CENG

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. As a result of the consolidation, Exelon and Generation recorded a net gain of $261 million within their respective Consolidated Statements of Operations and Comprehensive Income. This gain consists of approximately $136 million related to the step up to fair value basis of

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

Generation s ownership interest in CENG, and approximately $132 million related to the settlement of pre-existing transactions between CENG and Generation. The net gain on the consolidation of CENG of $261 million is net of a $7 million payment to EDF.

The fair value of CENG s assets and liabilities recorded in consolidation was determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The valuations necessary to assess the fair values of certain assets and liabilities were considered preliminary as a result of the short time period between the execution of the NOSA and the end of the second quarter of 2014. The estimates of the fair value of assets and liabilities could be modified for up to one year from April 1, 2014, as more information was obtained about the fair value of assets and liabilities. The principal items that have been revised include the asset retirement obligation liabilities and related asset retirement costs. These items have been updated with inputs from a third party engineering firm with corresponding adjustments recorded in 2014 and the first quarter of 2015. See Note 16 Asset Retirement Obligations for discussion of the impacts of adjustments recorded during 2014 and 2015 related to updated estimates of the CENG asset retirement obligation liabilities. In the period of such revisions, these and any other material changes to the fair value assessments have resulted in adjustments to the amounts recorded upon consolidation. In addition, the asset or liability adjustments impacting depreciation and/or accretion expense recorded after the consolidation date have impacted Generation s post-consolidation results of operations.

Generation recorded the assets and liabilities of CENG at fair value as of April 1, 2014. The following assets and liabilities of CENG were recorded within Generation s Consolidated Balance Sheets as of the date of integration, adjusted for the modifications discussed above:

Fair Values	**Exelon and Generation**
Current assets	$ 499
Nuclear decommissioning trust fund	1,955
Property, plant and equipment	3,073
Nuclear fuel	482
Other assets	10
Total assets	6,019
Current liabilities	237
Asset retirement obligation	1,816
Pension and other employee benefit obligations	281
Unamortized energy contract liabilities	171
Other liabilities	114
Total liabilities	2,619
Total net assets	$ 3,400

Generation also recorded the fair value of the noncontrolling interest on its Consolidated Balance Sheets of approximately $1.5 billion, net of the fair value of $152 million for certain specified additional distribution rights under the Operating Agreement. In addition, the noncontrolling interest was further reduced by the $400 million special cash distribution to EDF.

Table of Contents

Combined Notes to Consolidated Financial Statements (Continued)

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

Due to the Preferred Distribution Rights that Generation has on CENG s available cash, the earnings attributable to the noncontrolling interest on the Statements of Operations and Comprehensive Income as well as the corresponding adjustment to Noncontrolling interest on the Consolidated Balance Sheets will not be in proportion to Generation s and EDF s equity ownership interests. Rather, the attribution will consider Generation s Preferred Distribution Rights and allocate net income based on each owner s rights to CENG s net assets. For the years ended December 31, 2015 and 2014, Generation reduced by $18 million and $13 million, respectively, the amount of Net income attributable to noncontrolling interests on Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. As a result of the consolidation, Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income includes CENG s incremental operating revenues of $509 million and $218 million and CENG s net income (loss), prior to any intercompany eliminations and any adjustments for noncontrolling interest, of $(11) million and $407 million during the years ended December 31, 2015 and 2014, respectively.

Exelon and Generation incurred integration-related costs of $2 million and $26 million for the year ended December 31, 2015 and 2014, respectively. The costs incurred are classified primarily within Operating and maintenance expense in Exelon s and Generation s respective Consolidated Statements of Operations and Comprehensive Income.

6. Accounts Receivable (Exelon, Generation, ComEd, PECO and BGE)

Accounts receivable at December 31, 2015 and 2014 included estimated unbilled revenues, representing an estimate for the unbilled amount of energy or services provided to customers, and is net of an allowance for uncollectible accounts as follows:

2015	Exelon	Generation	ComEd	PECO	BGE
Unbilled customer revenues	$ 1,203	$ 732[a]	$ 218	$ 105	$ 148
Allowance for uncollectible accounts [b]	(284)	(77)	(75)	(83)[c]	(49)

2014	Exelon	Generation	ComEd	PECO	BGE
Unbilled customer revenues	$ 1,381	$ 823[a]	$ 204	$ 140	$ 214
Allowance for uncollectible accounts [b]	(311)	(60)	(84)	(100)[c]	(67)[d]

(a) Represents unbilled portion of retail receivables estimated under Exelon s unbilled critical accounting policy.
(b) Includes the allowance for uncollectible accounts on customer and other accounts receivable.
(c) Excludes the non-current allowance for uncollectible accounts of $8 million at both December 31, 2015 and 2014, related to PECO s current installment plan receivables described below.