ATLANTIC CITY ELECTRIC CO
Form 10-K
February 13, 2017
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2016

or

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

Commission File Number	**Name of Registrant; State or Other Jurisdiction 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 (800) 483-3220	23-2990190
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)**	36-0938600

	440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	
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
001-31403	**PEPCO HOLDINGS LLC** **(a Delaware limited liability company)** 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	52-2297449
001-01072	**POTOMAC ELECTRIC POWER COMPANY** **(a District of Columbia and Virginia corporation)** 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	53-0127880
001-01405	**DELMARVA POWER & LIGHT COMPANY** **(a Delaware and Virginia corporation)** 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	51-0084283
001-03559	**ATLANTIC CITY ELECTRIC COMPANY** **(a New Jersey corporation)** 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	21-0398280

Table of Contents

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

Title of Each Class	Name of Each Exchange on Which Registered
EXELON CORPORATION:	
Common Stock, without par value	New York and Chicago
Series A Junior Subordinated Debentures	New York
Corporate Units	New York
PECO ENERGY COMPANY:	
Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, $25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	New York
BALTIMORE GAS AND ELECTRIC COMPANY:	
6.20% Trust Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust II, fully and unconditionally guaranteed, by Baltimore Gas and Electric Company	New York

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

Title of Each Class

COMMONWEALTH EDISON COMPANY:

Common Stock Purchase Warrants, 1971 Warrants and Series B Warrants

POTOMAC ELECTRIC POWER COMPANY:

Common Stock, $.01 par value

DELMARVA POWER & LIGHT COMPANY:

Common Stock, $2.25 par value

ATLANTIC CITY ELECTRIC COMPANY:

Common Stock, $3.00 par value

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	No
Exelon Generation Company, LLC	Yes	No
Commonwealth Edison Company	Yes	No
PECO Energy Company	Yes	No
Baltimore Gas and Electric Company	Yes	No
Pepco Holdings LLC	Yes	No
Potomac Electric Power Company	Yes	No
Delmarva Power & Light Company	Yes	No
Atlantic City Electric Company	Yes	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
Exelon Generation Company, LLC	Yes	No
Commonwealth Edison Company	Yes	No
PECO Energy Company	Yes	No
Baltimore Gas and Electric Company	Yes	No
Pepco Holdings LLC	Yes	No
Potomac Electric Power Company	Yes	No
Delmarva Power & Light Company	Yes	No
Atlantic City Electric Company	Yes	No

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 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 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.

Table of Contents

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 Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
Exelon Corporation				
Exelon Generation Company, LLC				
Commonwealth Edison Company				
PECO Energy Company				
Baltimore Gas and Electric Company				
Pepco Holdings LLC				
Potomac Electric Power Company				
Delmarva Power & Light Company				
Atlantic City Electric Company				

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes No

The estimated aggregate market value of the voting and non-voting common equity held by nonaffiliates of each registrant as of June 30, 2016 was as follows:

Exelon Corporation Common Stock, without par value	$33,527,039,724
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
Pepco Holdings LLC	Not applicable
Potomac Electric Power Company	None
Delmarva Power & Light Company	None
Atlantic City Electric Company	None

The number of shares outstanding of each registrant s common stock as of January 31, 2017 was as follows:

Exelon Corporation Common Stock, without par value	926,589,614
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,017,157
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company, without par value	1,000
Pepco Holdings LLC	not applicable
Potomac Electric Power Company Common Stock, $.01 par value	100
Delmarva Power & Light Company Common Stock, $2.25 par value	1,000
Atlantic City Electric Company Common Stock, $3.00 par value	8,546,017

Documents Incorporated by Reference

Portions of the Exelon Proxy Statement for the 2017 Annual Meeting of

Shareholders and the Commonwealth Edison Company 2017 Information Statement are

incorporated by reference in Part III.

Exelon Generation Company, LLC, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City 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

PART III

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
Pepco Holdings or PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
Pepco	Potomac Electric Power Company
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
PCI	Potomac Capital Investment Corporation and its subsidiaries
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
BSC	Exelon Business Services Company, LLC
PHISCO	PHI Service Company
Exelon Corporate	Exelon in its corporate capacity as a holding company
PHI Corporate	PHI in its corporate capacity as a holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Antelope Valley	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
EGTP	ExGen Texas Power, LLC
EGR	ExGen Renewables I, LLC
AmerGen	AmerGen Energy Company, LLC
RPG	Renewable Power Generation
SolGen	SolGen, LLC
BondCo	RSB BondCo LLC
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
PETT	PECO Energy Transition Trust
ACE Funding or ATF	Atlantic City Electric Transition Funding LLC
Registrants	Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, collectively
Utility Registrants	ComEd, PECO, BGE, Pepco, DPL and ACE, collectively
Legacy PHI	PHI, Pepco, DPL and ACE, collectively
ConEdison Solutions	The competitive retail electricity and natural gas business of Consolidated Edison Solutions, Inc., a subsidiary of Consolidated Edison, Inc
UII	Unicom Investments, Inc.

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

Table of Contents

Other Terms and Abbreviations

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
AOCI	Accumulated Other Comprehensive Income
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
ASC	Accounting Standards Codification
BGS	Basic Generation Service
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CES	Clean Energy Standard
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
Conectiv	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE
Conectiv Energy	Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries, which were sold to Calpine in July 2010
Contract EDCs	Pepco, DPL and BGE, the Maryland utilities required by the MDPSC to enter into a contract for new generation
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTA	Consolidated tax adjustment
CTC	Competitive Transition Charge
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DCPSC	District of Columbia Public Service Commission
DC PLUG	District of Columbia Power Line Undergrounding
Default Electricity Supply	The supply of electricity by PHI s electric utility subsidiaries at regulated rates to retail customers who do not elect to purchase electricity from a competitive supplier, and which, depending on the jurisdiction, is also known as Standard Offer Service or BGS
Default Electricity Supply Revenue	Revenue primarily from Default Electricity Supply

DOE	United States Department of Energy
DOJ	United States Department of Justice

Other Terms and Abbreviations

DPSC	Delaware Public Service Commission
DRP	Direct Stock Purchase and Dividend Reinvestment Plan
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDCs	Electric distribution companies
EDF	Electricite de France SA and its subsidiaries
EE&C	Energy Efficiency and Conservation/Demand Response
EGS	Electric Generation Supplier
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EmPower Maryland	A Maryland demand-side management program for Pepco and DPL
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
FEJA	Illinois Public Act 99-0906 or Future Energy Jobs Act
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GCR	Gas Cost Rate
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
HSR Act	The Hart-Scott-Rodino Antitrust Improvements Act of 1976
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
Integrys	Integrys Energy Services, Inc.
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
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

Table of Contents

Other Terms and Abbreviations

LLRW	Low-Level Radioactive Waste
LT Plan	Long-term renewable resources procurement plan
LTIP	Long-Term Incentive Plan
MAPP	Mid-Atlantic Power Pathway
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody s	Moody s Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGS	Natural Gas Supplier
NJBPU	New Jersey Board of Public Utilities
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
NOSA	Nuclear Operating Services Agreement
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NUGs	Non-utility generators
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPC	Office of People s Counsel
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PHI Retirement Plan	PHI s noncontributory retirement plan
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables

PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
Preferred Stock	Originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share

Other Terms and Abbreviations

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 or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
ROE	Return on equity
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RSSA	Reliability Support Services Agreement
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 from DOE
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOCAs	Standard Offer Capacity Agreements required to be entered into by ACE pursuant to a New Jersey law enacted to promote the construction of qualified electric generation facilities in New Jersey
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
Transition Bond Charge	Revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees
Transition Bonds	Transition Bonds issued by ACE Funding
Upstream	Natural gas and oil exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit
ZES	Zero Emission Standard

5

Table of Contents

FILING FORMAT

This combined Annual Report on Form 10-K is being filed separately by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (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 24; 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.

PART I

ITEM 1. BUSINESS
General

Corporate Structure and Business and Other Information

Exelon, incorporated in Pennsylvania in February 1999, is a utility services holding company engaged, through Generation, in the energy generation business, and through ComEd, PECO, BGE, PHI, Pepco, DPL and ACE 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. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions.

Table of Contents

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.

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.

PHI

PHI is a utility services holding company engaged, through its reportable segments Pepco, DPL and ACE, in the energy delivery businesses discussed below. On March 23, 2016, Pepco Holdings, Inc., converted from a Delaware corporation to a Delaware limited liability company, Pepco Holdings LLC. PHI s principal executive offices are located at 701 Ninth Street, N.W., Washington, D.C. 20068, and its telephone number is 202-872-2000.

Pepco

Pepco 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 the District of Columbia and major portions of

Montgomery County and Prince George s County in Maryland.

Table of Contents

Pepco was incorporated in the District of Columbia in 1896 and Virginia in 1949. Pepco s principal executive offices are located at 701 Ninth Street, N.W., Washington, D.C. 20068, and its telephone number is 202-872-2000.

DPL

DPL 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 portions of Delaware and Maryland, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in portions of New Castle County in Delaware.

DPL was incorporated in Delaware in 1909 and Virginia in 1979. DPL s principal executive offices are located at 500 North Wakefield Drive, Newark, Delaware 19702, and its telephone number is 202-872-2000.

ACE

ACE 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 portions of southern New Jersey.

ACE was incorporated in New Jersey in 1924. ACE s principal executive offices are located at 500 North Wakefield Drive, Newark, Delaware 19702, and its telephone number is 202-872-2000.

Business Services

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.

PHI Service Company, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHI Service Company and the participating operating subsidiaries.

Operating Segments

See Note 26 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on Exelon s operating segments.

Merger with Pepco Holdings, Inc. (Exelon)

On March 23, 2016, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Purple Acquisition Corp., a wholly owned subsidiary of Exelon (Merger Sub) and Pepco Holdings, Inc. (PHI). As a result of that merger, Merger Sub was merged into PHI (the PHI Merger) with PHI surviving as a wholly owned subsidiary of Exelon and Exelon Energy Delivery Company, LLC (EEDC), a wholly owned subsidiary of Exelon which also owns Exelon s interests in ComEd, PECO and BGE (through a special purpose subsidiary in the case of BGE). Following the completion of the

8

Table of Contents

PHI Merger, Exelon and PHI completed a series of internal corporate organization restructuring transactions resulting in the transfer of PHI s unregulated business interests to Exelon and Generation and the transfer of PHI, Pepco, DPL and ACE to a special purpose subsidiary of EEDC. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the PHI 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, in competitive energy markets 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 also provides geographic and supply source diversity. 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 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 interests 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.

Acquisitions

ConEdison Solutions. On September 1, 2016, Generation acquired the competitive retail electric and natural gas business activities of ConEdison Solutions, a subsidiary of Consolidated Edison, Inc., for a purchase price of $257 million including net working capital of $204 million. The renewable energy, sustainable services and energy efficiency businesses of ConEdison were excluded from the transaction.

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.

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.

Dispositions

Upstream Disposition. On June 16, 2016, Generation initiated the sales process of its Upstream business. See Note 14 Debt and Credit Agreements for more information. In December 2016, Generation sold substantially all of the Upstream assets for $37 million which resulted in a pre-tax loss on sale of $10 million which is included in Gain(loss) on sales of assets on Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2016.

Asset Divestitures. During 2014 and 2015, Generation sold certain generating assets with total pre-tax proceeds of $1.8 billion (after-tax proceeds of approximately $1.4 billion). Proceeds were used primarily to finance a portion of the acquisition of PHI.

Table of Contents

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, 2016, the generating resources of Generation consisted of the following:

Type of Capacity	**MW**
Owned generation assets [(a)(b)]	
Nuclear	19,457
Fossil (primarily natural gas and oil)	9,548
Renewable [(c)]	3,715
Owned generation assets	32,720
Long-term power purchase contracts [(d)]	6,879
Total generating resources	39,599

(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 wind, hydroelectric, and solar generating assets.
(d) Electric supply procured under site specific agreements.

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).

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).

Table of Contents

See Note 26 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 19,457 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. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the impact of the Future Energy Jobs Bill and New York CES on certain nuclear plants.

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 2016, 2015 and 2014 electric supply (in GWh) generated from the nuclear generating facilities was 67%, 68% and 67%, 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.

On August 8, 2016, Generation executed a series of agreements with Entergy Nuclear FitzPatrick LLC (Entergy) to acquire the 838MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station located in Scriba, New York. Closing of the transaction is currently anticipated to occur in the first half of 2017 and requires regulatory approval by FERC, NRC and the New York Public Service Commission (NYPSC). The transaction is also subject to the notification and reporting requirements of the HSR Act (which has been completed) and other customary closing conditions. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail on the proposed acquisition of the FitzPatrick nuclear generating station.

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

During 2016, 2015 and 2014, the nuclear generating facilities operated by Generation achieved capacity factors of 94.6%, 93.7% and 94.3%, 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

12

Table of Contents

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 30, 2017, the NRC categorized Ginna 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, 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.

For information on the NRC actions related to the Japan Earthquake and Tsunami and the industry s response, see ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Executive Overview.

Licenses. Generation has original 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals from the NRC for all its nuclear units except Clinton. Additionally, PSEG 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.

Table of Contents

The following table summarizes the current operating license expiration dates for Generation s nuclear facilities in service:

Station	Unit	In-Service Date (a)	Current License Expiration
Braidwood	1	1988	2046
	2	1988	2047
Byron	1	1985	2044
	2	1987	2046
Calvert Cliffs	1	1975	2034
	2	1977	2036
Clinton (b)	1	1987	2026
Dresden	2	1970	2029
	3	1971	2031
LaSalle	1	1984	2042
	2	1984	2043
Limerick	1	1986	2044
	2	1990	2049
Nine Mile Point	1	1969	2029
	2	1988	2046
Oyster Creek (c)	1	1969	2029
Peach Bottom (d)	2	1974	2033
	3	1974	2034
Quad Cities	1	1973	2032
	2	1973	2032
R.E. Ginna	1	1970	2029
Salem	1	1977	2036
	2	1981	2040
Three Mile Island	1	1974	2034

(a) Denotes year in which nuclear unit began commercial operations.
(b) 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.
(c) In December 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. In 2016, Exelon notified the NRC that it will cease operations at Oyster Creek on November 30, 2019.
(d) On June 7, 2016, Generation announced that it will submit a second 20 year license renewal application to NRC for Peach Bottom Units 2 and 3 in 2018.

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. To date, each granted license renewal has been 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 renewal of operating licenses for all of Generation s operating nuclear generating stations except for Oyster Creek and Clinton. Oyster Creek depreciation provisions are based on the 2019 expected shutdown date. Clinton depreciation provisions are based on 2027 which is the last year of the Illinois Zero Emissions Standard. See Note

3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional detail on the new Illinois legislation and Note 9 Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional detail on the reversal of the decision to early retire Clinton.

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. On

December 16, 2016, Generation was notified by OPPD of the termination of the operating services agreement for Fort Calhoun Station effective June 14, 2017. OPPD has the option to continue to use the Exelon Nuclear Management Model for payment of a fee.

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 on-site in 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, 2016, Generation had approximately 77,900 SNF assemblies (19,200 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 Three Mile Island, where such storage is projected to be in operation 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 24 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 store and stage for shipping Class B and Class C LLRW. Generation has a contract through 2032 to ship Class B and Class C LLRW to a disposal facility in Texas. The agreement provides for disposal of all current Class B and Class C LLRW currently stored at 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

Table of Contents

reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See Nuclear Insurance within Note 24 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 future financial conditions and results of operations and cash flows.

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. 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, 2016 at fair value of approximately $11.1 billion and have an estimated targeted annual pre-tax return of 5.3% to 5.9%.

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.

Fossil and Renewable Facilities (including Hydroelectric)

At December 31, 2016, Generation had ownership interests in 13,263 MW of capacity in generating facilities currently in service, consisting of 9,522 MW of natural gas and oil, 3,715 MW of renewables (wind, hydroelectric, and solar) and 26 MW of waste coal. Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) jointly owned facilities that include Wyman; (2) certain wind project entities with minority interest owners; and (3) 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 regarding certain of these entities which are VIEs. Generation s fossil and renewable generating stations are all operated by Generation, with the exception of LaPorte

16

and Wyman, which are operated by third parties. In 2016, 2015 and 2014, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 10%, 8% and 13%, 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 the 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 actual and anticipated license renewal periods. 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 future financial conditions 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, 2016:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic	16	2017 - 2032	800
Midwest	6	2017 - 2026	1,236
New England	8	2017	650
ERCOT	5	2020 - 2031	1,501
Other Power Regions	11	2017 - 2030	2,692
Total	46		6,879

	2017	2018	2019	2020	2021
Capacity Expiring (MW)	1,790	101	644	980	815

Fuel

The following table shows sources of electric supply in GWh for 2016 and 2015:

	Source of Electric Supply	
	2016	2015
Nuclear [(a)]	176,799	175,474
Purchases non-trading portfolio	59,987	63,637
Fossil (primarily natural gas and oil)	19,830	14,936
Renewable [(b)]	6,324	5,982
Total supply	262,940	260,029

(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 2016 and 2015 includes physical volumes of 33,444 GWh and 33,415 GWh, respectively, for CENG.

(b) Includes wind, hydroelectric, 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 2017. 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.

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

Table of Contents

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 sells electricity, natural gas, and other energy 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.

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 2017 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, 2016, the percentage of expected generation hedged for the major reportable segments was 91%-94%, 56%-59% and 28%-31% for 2017, 2018, and 2019, 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 generating facilities based upon a simulated dispatch model that

19

Table of Contents

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, BGE, Pepco, DPL, and ACE 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.

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 2017 are as follows:

(in millions)	
Nuclear fuel [(a)]	$ 925
Growth	600
Production plant	1,125
Total	$ 2,650

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

ComEd

ComEd is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to 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 2017 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

20

Table of Contents

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.

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. Pursuant to statute, public service companies in Maryland may exercise a franchise to the extent authorized by the MDPSC. The service territory for BGE, as well as for other electric utilities in the state, was precisely delineated in 1966 by the MDPSC and has been modified in minor ways over the years. 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.

PHI

PHI was incorporated in Delaware in 2001. Through its reportable segments Pepco, DPL and ACE, PHI is engaged primarily in the transmission, distribution and default supply of electricity, and, to a lesser extent, the distribution and supply of natural gas. On March 23, 2016, Pepco Holdings, Inc., converted from a Delaware corporation to a Delaware limited liability company, Pepco Holdings LLC. PHI Service Company, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries.

21

Table of Contents

Pepco

Pepco is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in the District of Columbia and major portions of Prince George s County and Montgomery County in Maryland. Pepco is a public utility under the Code of the District of Columbia and subject to regulation by the DCPSC related to distribution rates and service, the issuance of securities and certain other aspects of Pepco s business in the District of Columbia. Pepco is also an electric company under the Maryland Public Utilities Article of the Maryland Annotated Code subject to regulation by the MDPSC related to distribution rates and service, the issuance of securities and certain other aspects of Pepco s business in Maryland. Pepco is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of Pepco s business. Additionally, Pepco is subject to NERC mandatory reliability standards.

Pepco s right to occupy public space for utility purposes is by permit from the District of Columbia and the federal government. Pepco is the only public utility that distributes electricity for sale to the public in the District of Columbia. In Maryland, Pepco operates pursuant to state-wide franchises granted by Maryland s General Assembly that are unlimited in duration. Pursuant to statute, public service companies in Maryland may exercise a franchise to the extent authorized by the MDPSC. The service territories for Pepco, as well as for other electric utilities in the state, were precisely delineated in 1966 by the MDPSC and have been modified in minor ways over the years.

DPL

DPL 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 portions of Maryland and Delaware, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in New Castle County, Delaware. DPL is a public utility under the Delaware Code and subject to regulation by the DPSC related to electric and gas distribution rates and service, the issuance of certain securities and certain other aspects of DPL s business in Delaware. In Maryland, DPL is an electric company under the Public Utilities Article of the Maryland Annotated Code subject to regulation by the MDPSC related to electric rates and service, the issuances of certain securities and certain other aspects of DPL s business in Maryland. DPL is a public utility under the Federal Power Act and is subject to regulation by FERC related to transmission rates and certain other aspects of DPL s business and by the U.S. Department of Transportation related to pipeline safety and other areas of gas operations. Additionally, DPL is also subject to NERC mandatory reliability standards.

DPL 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. In Maryland, DPL operates pursuant to state-wide franchises that are substantially similar in nature to those described above with respect to Pepco s Maryland operations. DPL s exclusive and continuing authority to distribute electricity and natural gas in its non-municipal service territories in Delaware is derived from legislation, through which the DPSC has established exclusive service territories. With respect to municipalities that it serves, DPL provides service under various franchises granted to DPL and predecessor companies, which franchises are generally either unlimited as to time or renew automatically.

ACE

ACE 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 portions of southern New

Table of Contents

Jersey. ACE is a public utility under the New Jersey Public Utilities Act subject to regulation by the NJBPU related to distribution rates and service, the issuance of securities and certain other aspects of ACE s business. ACE is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of ACE s business. Additionally, ACE is subject to NERC mandatory reliability standards.

ACE s franchises are sufficient to permit it to engage in the business it now conducts. ACE operates under non-exclusive franchises that have been granted by the NJBPU and under certain non-exclusive consents from municipalities in which ACE provides service. While most of the municipal consents were granted in perpetuity, two of the municipal consents require renewal on a periodic basis in accordance with their terms with respect to ACE s continued right to erect and maintain wires and poles in, upon, over and under the public streets, streets and alleys, and are subject to the ultimate review and approval of the NJBPU. All of the franchises and consents are currently in full force and effect.

ComEd, PECO, BGE, Pepco, DPL and ACE

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 the Utility Registrants as of December 31, 2016:

	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	9.4[(a)]	9.4	n/a	4.0	4.0	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	2.9	1.3	1.3	0.7
Pepco	640	640	n/a	2.4[(d)]	2.4	n/a	0.9	0.9	n/a
DPL	5,675	5,400	275	2.0[(e)]	1.4	0.6	0.6	0.5	0.1
ACE	2,800	2,800	n/a	1.1[(f)]	1.1	n/a	0.5	0.5	n/a

(a) Includes approximately 2.7 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.
(d) Includes approximately 0.7 million in the District of Columbia.
(e) Includes approximately 0.1 million in the city of Wilmington.
(f) Includes approximately 0.1 million in the city of Atlantic City.

Peak Deliveries. The Utility Registrants 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, BGE and DPL natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating.

Table of Contents

The following table summarizes historic peak deliveries for the Utility Registrants for electric and gas deliveries during peak demand months through December 31, 2016:

	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
Pepco	7/22/2011	7.02	2/20/2015	6.07	n/a	n/a
DPL	7/22/2011	4.14	2/20/2015	4.11	2/15/2015	186
ACE	7/22/2011	2.96	1/7/2014	1.8	n/a	n/a

Electric and Natural Gas Distribution Services. The Utility Registrants 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, BGE s and DPL s electric and gas distribution costs and Pepco s and ACE s electric distribution costs are recovered through traditional rate case proceedings. In certain instances, the Utility Registrants use specific recovery mechanisms as approved by their respective regulatory agencies.

ComEd, Pepco, and ACE customers have the choice to purchase electricity, and PECO, BGE, and DPL customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. The Utility Registrants remain the distribution service providers for all customers and are obligated to deliver electricity and natural gas to customers in their respective service territories while charging a regulated rate for distribution service. In addition, the Utility Registrants also retain significant default service obligations to provide electricity to certain groups of customers in their respective service areas who do not choose a competitive electric generation supplier. PECO and BGE also retain significant default service obligations to provide natural gas to certain groups of customers in their respective service areas who do not choose a competitive natural gas supplier. For natural gas, DPL does not retain default service obligations. For those customers that choose a competitive electric generation or natural gas supplier, the Utility Registrants may act as the billing agent but do not record revenues or purchased power and fuel expense related to the electricity and/or natural gas. For those customers that choose one of the Utility Registrants as their electric generation or natural gas supplier, the Utility Registrants 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 revenues net of purchased power and fuel expense.

The following table outlines the state regulatory agencies and default service obligations for each of the Utility Registrants:

	Regulatory Agency	Default Service Obligation-Electricity	Default Service Obligation-Natural Gas
ComEd	ICC	POLR	n/a
PECO	PAPUC	DSP	PGC

BGE	MDPSC	SOS	MBR
Pepco	DCPSC/MDPSC	SOS	n/a
DPL	DPSC/MDPSC	SOS	n/a
ACE	NJBPU	BGS	n/a

Table of Contents

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 the Utility Registrants consisted of the following at December 31, 2016, 2015 and 2014:

	December 31, 2016					
	Number of retail customers in customer choice programs		% of total retail customers		Customer choice program deliveries as a % of retail sales (for the year ended)	
	Electric	Natural gas	Electric	Natural gas	Electric	Natural gas
ComEd	1,502,900	n/a	38%	n/a	72%	n/a
PECO	587,200	81,300	36%	16%	70%	26%
BGE	337,000	151,000	27%	23%	59%	57%
Pepco	176,372	n/a	21%	n/a	65%	n/a
DPL	78,994	156	15%	0.1%	51%	28%
ACE	94,562	n/a	17%	n/a	47%	n/a

	December 31, 2015					
	Number of retail customers in customer choice programs		% of total retail customers		Customer choice program 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%
Pepco	173,222	n/a	21%	n/a	65%	n/a
DPL	77,603	159	15%	0.1%	51%	31%
ACE	78,299	n/a	14%	n/a	45%	n/a

	December 31, 2014					
	Number of retail customers in customer choice programs		% of total retail customers		Customer choice program 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%
Pepco	179,524	n/a	22%	n/a	65%	n/a
DPL	78,153	157	15%	0.1%	53%	31%
ACE	86,780	n/a	16%	n/a	51%	n/a

(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.

Procurement-Related Proceedings. The Utility Registrants electric supply for its customers is primarily procured through contracts as required by the ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU. The Utility Registrants 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 the Utility Registrants Statements of Operations and Comprehensive Income.

Table of Contents

PECO s, BGE s and DPL s natural gas supplies are purchased from a number of suppliers for terms of up to three years. PECO, BGE and DPL have annual firm supply and transportation contracts of 132,000 mmcf, 128,000 mmcf and 58,000 mmcf, respectively. In addition, to supplement gas supply at times of heavy winter demands and in the event of temporary emergencies, PECO, BGE and DPL 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	1,056	550	22,000
DPL	257	n/a	3,800

(a) Natural gas from underground storage represents approximately 28%, 46% and 34% of PECO s, BGE s and DPL s 2016-2017 heating season planned supplies, respectively.

PECO, BGE and DPL 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, BGE and DPL make these sales as part of a program to balance its supply and cost of natural gas.

Energy Efficiency Programs. The Utility Registrants 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. The Utility Registrants businesses are capital intensive and require significant investments, primarily in electric transmission and distribution and natural gas transportation and distribution facilities, to ensure the adequate capacity, reliability and efficiency of their systems. ComEd s, PECO s, BGE s, Pepco s, DPL s and ACE s most recent estimates of capital expenditures for plant additions and improvements for 2017 are $2,200 million, $775 million, $925 million, $625 million, $375 million and $300 million, respectively.

ComEd, PECO, BGE, Pepco and DPL have AMI smart meter and smart grid deployment programs within their respective service territories to enhance their distribution systems. PECO, BGE, Pepco and DPL have completed the installation and activation of smart meters in their respective service territories. ACE has yet to receive approval from the NJBPU to proceed with the installation of AMI smart meters.

Transmission Services. The Utility Registrants provide unbundled transmission service under rates approved by FERC. Under FERC s open access transmission policy promulgated in Order No. 888, the Utility Registrants, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates. The Utility Registrants and their affiliates are required to comply with FERC s Standards of Conduct regulation governing the communication of non-public transmission information between the transmission owner s employees and wholesale merchant employees.

PJM is the regional grid operator and operates pursuant to FERC-approved tariffs. 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. The Utility Registrants

Table of Contents

are members of PJM and provide regional transmission service pursuant to the PJM Tariff. The Utility Registrants and the other transmission owners in PJM have turned over control of their transmission facilities to PJM, and their transmission systems are 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 transmission owners at rates based on the costs of transmission service.

ComEd s transmission rates are established based on a formula that was approved by FERC in January 2008. BGE s, Pepco s, DPL s and ACE s transmission rates are established based on a formula that was approved by FERC in April 2006. FERC s orders establish 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 26 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 additional information regarding transmission services.

Employees

As of December 31, 2016, Exelon and its subsidiaries had 34,396 employees in the following companies, of which 11,984 or 35% were covered by collective bargaining agreements (CBAs):

	IBEW Local 15 (a)	IBEW Local 614 (b)	Other CBAs	Total Employees Covered by CBAs	Total Employees
Generation (c)	1,640	99	2,635	4,374	14,717
ComEd	3,777			3,777	6,574
PECO		1,310		1,310	2,651
BGE (d)					3,097
PHI (e)			331	331	1,670
Pepco (e)			1,056	1,056	1,466
DPL (e)			631	631	871
ACE (e)			399	399	595
Other (f)	65		41	106	2,755
Total	5,482	1,409	5,093	11,984	34,396

(a) A separate CBA between ComEd and IBEW Local 15 covers approximately 62 employees in ComEd s System Services Group and was renewed in 2016. Generation s and ComEd s separate CBAs with IBEW Local 15 will expire in 2022.

(b) 1,310 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 covering 99 employees, which was renewed in 2016 and expiring in 2019.

(c) During 2016, Generation finalized its CBA with the Security Officer union at Oyster Creek, expiring in 2022 and New Energy IUOE Local 95-95A, which will expire in 2021. Also during 2016, Pepco Energy Services was allocated to Generation with a total of 358 employees broken down as follows: 229 employees covered by CBAs and 129 non-represented employees. 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 two 3-year agreements: New England ENEH, UWUA Local 369, which will expire in 2017.

Table of Contents

(d) In January 2017, an election was held at BGE which resulted in union representation for approximately 1,400 employees. BGE and IBEW Local 410 will begin negotiations for an initial agreement which could result in some modifications to wages, hours and other terms and conditions of employment. No agreement has been finalized to date and management cannot predict the outcome of such negotiations.
(e) PHI s utility subsidiaries are parties to five collective bargaining agreements with four local unions. Collective bargaining agreements are generally renegotiated every three to five years. All of these collective bargaining agreements were renegotiated in 2014 and were extended through various dates ranging from October 2018 through June 2020
(f) Other includes shared services employees at BSC.

Environmental Regulation

General

The Registrants 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, BGE, Pepco, DPL and ACE. 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, BGE, Pepco, DPL and ACE oversee environmental, health and safety issues related to these companies.

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 (SO2), nitrogen oxides (NOx), mercury and other pollutants and require permits for operation of emissions sources. Such permits have been obtained by Exelon s subsidiaries and must be renewed periodically. The Clean Air Act establishes a comprehensive and complex national program to 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.

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

Table of Contents

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 any 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, Peach Bottom, Quad Cities, Riverside and Salem.

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 could 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.

Pursuant to discussions with the NJDEP in 2010 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. The agreement only applies to Oyster Creek based on its unique circumstances and does not set any precedent for the ultimate compliance requirements for Section 316(b) at Exelon s other plants.

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 is 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

29

continue to operate utilizing the existing once-through cooling water system with certain required system modifications. On July 28, 2016, the NJDEP issued a final permit for Salem that did not require the installation of cooling towers. However, the permit is being challenged by an environmental organization, and if successful, could result in additional costs for Clean Water Act compliance.

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 Delaware, District of Colombia, Illinois, Maryland, New Jersey 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, BGE, Pepco, DPL and ACE 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 24 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 2017 at Exelon for compliance with environmental remediation related to contamination at former MGP sites and other gas purification sites is expected to total $41 million, consisting of $35 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, 2016, Generation has established appropriate contingent liabilities for potential 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.

The Utility Registrants also have environmental liabilities for remediation considerations. As of December 31, 2016, Generation has established appropriate contingent liabilities for potential environmental remediation requirements.

30

Table of Contents

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

See Notes 3 Regulatory Matters and 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants environmental remediation efforts and related impacts to the Registrants results of operations, cash flows and financial positions.

Global Climate Change

Exelon has utility and generation assets, and customers, that are subject to the effects of climate change as described in the Intergovernmental Panel on Climate Change (IPCC) 5th Assessment Report, published in 2014, Accordingly the company is engaged in a variety of initiatives to better understand and develop responses to these issues, including investments in resiliency, partnering with federal, state and local governments and advocating for science-based public policy. Exelon, as a producer of electricity from predominantly low-carbon generating facilities (such as nuclear, hydroelectric, wind and solar photovoltaic), has a relatively small greenhouse gas (GHG) emission profile, or carbon footprint, compared to other domestic generators of electricity. By virtue of its significant investment in low-carbon intensity assets, Generation s emission intensity, or rate of carbon dioxide equivalent (CO_2e) emitted per unit of electricity generated, is among the lowest in the industry. Exelon does produce GHG emissions, primarily at its fossil fuel-fired generating plants (primarily natural gas); CO_2, methane and nitrous oxide are all emitted in this process, with CO_2 representing the largest portion of these GHG emissions. GHG emissions from combustion of fossil fuels represented the majority of Exelon s direct GHG emissions in 2016, although less than 30 percent of its owned generating capacity utilizes fossil fuels with less than 10 percent of owned generation MWh actually produced by fossil fuels as Exelon s fossil-fired generation is primarily intermediate and peaking in nature. Other GHG emission sources at Exelon include natural gas (methane) leakage on the natural gas systems, sulfur hexafluoride (SF_6) leakage in its electric transmission and distribution operations and refrigerant leakage from its chilling and cooling equipment as well as fossil fuel combustion in its motor vehicles and 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 to 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 entered into force on November 4, 2016 the thirtieth day after the date on which at

31

least 55 Parties accounting for at least an estimated 55% of total global greenhouse gas emissions ratified the Agreement. The Agreement has not been ratified by the US Senate and it is uncertain whether or not or to what extent the new Trump Administration will pursue the established target.

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.

Under the Obama Administration, the EPA proposed and finalized regulations for new and modified fossil-fuel power plants under Section 111(b) of the Clean Air Act and Section 111(d) for existing fossil-fuel power plants. These regulations are currently being litigated. The 111(d) regulations, referred to as the Clean Power Plan, are currently subject to a stay by the Supreme Court, pending conclusion of all litigation at both the D.C. Circuit and Supreme Court levels. The D.C. Circuit heard *en banc* oral argument in late September 2016, but has not yet issued its decision. Prior to the stay, the Clean Power Plan had established GHG emission reduction targets for each state, with emission reductions slated to begin in 2022. State requirements to submit plans to EPA in September 2016 (or within two years if an extension was requested) were placed in abeyance pending results of litigation.

President Trump s election platform called for eliminating a number of EPA regulations, including the Clean Power Plan. Due to the need to appoint and confirm key EPA officials as the Trump Administration begins to govern, the specific details of the Trump Administration s plans to address the Clean Power Plan are not known. In the interim, the D.C. Circuit continues its review of the regulation under existing litigation and is expected to issue its decision in the first half of 2017.

Due to current litigation and the need for the new Administration to develop its approach to dealing with the Clean Power plan, Exelon and Generation cannot at this time predict the future of the Clean Power Plan or individual state responses to Clean Power Plan developments or how developments will impact their future financial positions, 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). Allowance prices in 2016 remained below the applicable CCR trigger price, indicating program costs remained within the boundaries of costs acceptable to participating states. During 2016, RGGI began its quadrennial review process to determine what, if any, program design amendments should be pursued for the regional program. A series of stakeholder calls occurred in 2016, which included discussion around potential linkage issues with the federal Clean Power Plan, linkages to state GHG emission reduction goals/programs, functioning of cost containment mechanisms, and consideration of whether future cap levels should be adjusted for the post-2020 period. RGGI intends to complete its program review in early 2017.

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.

32

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 green house gas emissions (GHG) was realized with the passage of the Greenhouse Gas Emissions Reduction Act of 2009 (GGRA) which required 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 listed Maryland s electricity consumption reduction goals, required under the EmPOWER Maryland program, and mandatory State participation in RGGI Program, as the energy sector s contribution to the plan. In April 2016, the Governor of Maryland signed the GGRA of 2016 into law, which updated the state s Climate Commission charter. It expanded membership to include more non-governmental members and established an enhanced statewide GHG emissions reduction target of 40 percent from 2006 levels by 2030, maintaining the caveats from the 2007 legislation that the implementation have a net positive impact on both jobs and the economy. MDE is currently working on plans to meet the 2016 GGRA requirements. In February of this year (2017) , the Maryland General Assembly overrode Maryland Governor Hogan s veto of legislation that requires the current Renewable Portfolio Standard (RPS) to be accelerated and enhanced. The law requires the RPS, previously set at 20% renewables by 2022, with a 2% solar carve out, to move to 25% renewables by 2020 with a 2.5% solar carve out.

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, Maryland, the District of Columbia, Delaware and New Jersey 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.

In Illinois, in accordance with legislation in effect on December 31, 2016, the IPA s Procurement Plans include the procurement of cost-effective renewable energy resources in amounts that equal or exceed a minimum target percentage of the total electricity that each electric utility supplies to its eligible retail customers. The June 1, 2016 target renewable energy resources obligation for the utilities was at least 11.5%. This obligation increases by at least 1.5% each year thereafter to 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, 2016, ComEd had purchased renewable energy resources or equivalents, such as RECs, in accordance with the IPA Procurement Plan. 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.

In accordance with FEJA that takes effect on June 1, 2017, beginning with the plan or plans to be implemented in the 2017 delivery year, the IPA shall develop a long term renewable resources procurement plan (LT Plan). The RPS target percentages for the overall service territory have not changed through June 1, 2025 (11.5% of retail load by June 1 2016 growing to 25% by June 1 2025) although FEJA extended the 25% RPS target to delivery years after 2025. Currently, each Retail

Electric Supplier and each utility is responsible for the renewable resource obligation for the customers to which it supplies power. Over time, this will change and the utility will procure renewable resources based on the retail load of substantially all customers in its service territory. For the delivery year beginning June 1, 2017, the LT Plan shall include cost effective renewable energy resources procured by the utility for the retail load the utility supplies and for 50% of the retail customer load supplied by Retail Electric Suppliers in the utility service territory on February 28, 2017. Utility procurement for RES supplied retail customer load will increase to 75% June 1, 2018 and to 100% beginning June 1, 2019.

Originally passed November 30, 2004 the AEPS Act became effective for PECO on January 1, 2011. During 2016, PECO was required to supply approximately 5.5% 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, 2016 and subsequently 6.0% beginning June 1, 2016 and continuing through May 31, 2017. PECO is also required to supply 8.2% 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, effective June 1, 2015 and continuing through May 31, 2020. 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 purchases its AECs through its DSP Program full requirement contracts with various counterparties, including Generation. PECO also obtains AECs of Solar Tier I annually from long term agreements with various counterparties, including Generation, and balancing amounts of Tier 1 non-solar and Tier II through broker purchases.

Section 7-703 of the Public Utilities Article in Maryland sets forth the RPS requirement, which applies to all retail electricity sales in Maryland by electricity suppliers. The RPS requirement requires that suppliers obtain a specified percentage of the electricity it sells from Tier 1 sources (solar, wind, biomass, methane, geothermal, ocean, fuel cell, small hydroelectric, and poultry litter) and Tier 2 sources (hydroelectric, other than pump storage generation, and waste-to-energy). The RPS requirement began in 2006, requiring that suppliers procure 1.0% and 2.5% from Tier 1 and Tier 2 sources, respectively, escalating in 2022 to 22.0% from Tier 1 sources, including at least 2.0% from solar energy, and a phase out of Tier 2 resource options by 2022. In 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, Pepco and DPL are subject to requirements established by the Public Utilities Article in Maryland related to the use of alternative energy resources. In addition, the wholesale suppliers that supply power to BGE, Pepco and DPL through SOS procurement auctions have the obligation, by contract with BGE, Pepco and DPL, to meet the RPS requirements.

Section 34-1432 of the D.C. Code sets forth the RPS requirement, which applies to all retail electricity sales in the District of Columbia by electricity suppliers. The RPS requirement requires that suppliers obtain a specified percentage of the electricity it sells from Tier 1 sources (solar, wind, certain qualifying biomass, methane from anaerobia decomposition of organic materials in landfill or wastewater treatment plant, geothermal, ocean, and fuel cell) and Tier 2 sources (hydroelectric (other than pumped storage generation), certain qualifying biomass and waste-to-energy). The RPS requirement began in 2007, with standards increasing annually. For 2017, the RPS requires that suppliers procure 13.1% and 2.5% from Tier 1 and Tier 2 sources, respectively, with not less than 0.95% solar, and escalating in 2023 to 20.0% from Tier 1 sources, including at least 2.5% from solar energy, and a phase out of Tier 2 resource options. In 2015 the law was amended to extend the RPS requirements to 2032, at which time not less than 50% is required from Tier 1 renewable sources, including at least 5.0% derived from solar energy. Tier 2 renewable sources remain phased out. The wholesale suppliers that supply power to Pepco through SOS procurement auctions have the obligation, by contract with Pepco, to meet the RPS requirements.

Table of Contents

Title 26 of the Delaware Code sets forth the RPS requirement, which applies to retail electricity sales in Delaware by electricity suppliers. The RPS requirement requires that DPL obtain a specified percentage of the electricity it delivers to its eligible customers from eligible energy resources (solar electric, wind, ocean tidal, ocean thermal, fuel cells powered by renewable fuels, hydroelectric facilities with a maximum capacity of 30 MW, sustainable biomass, anaerobic digestion and landfill gas). The RPS requirement, beginning in 2007, required that suppliers procure 2.0% from eligible energy resources, with not less than 0.011% from solar, and escalating annually through 2025, at which time suppliers must procure 25.0% from eligible energy resources, including at least 3.5% from solar. As of December 31, 2016, DPL is a party to three land-based wind power purchase agreements in the aggregate amount of 128 MWs (nameplate capacity). DPL has contracted for approximately 48 MW of Solar Renewable Energy Credits (SRECs) through a combination of long term SREC purchase agreements with solar facilities, SREC Purchase agreements with the Delaware Sustainable Energy Utility and the DE SREC Procurement Program. On October 18, 2011, the DPSC approved a tariff submitted by DPL in accordance with the requirements of the RPS specific to a fuel cell facility totaling 30 MWs to be constructed by a qualified fuel cell provider. The tariff and the RPS establish that DPL acts solely as an agent to collect payments in advance from its distribution customers and remit them to the qualified fuel cell provider for each MWh of energy produced by the fuel cell facilities through 2033. The qualified fuel cell provider output reduces the non-solar and/or solar requirements needed to satisfy the Delaware RPS obligations.

The Electric Discount and Energy Competition Act, (EDECA), was signed into law in 1999, and includes the requirement for compliance with New Jersey s RPS by electric power suppliers and providers of BGS. The RPS requires that electric power suppliers obtain a specified percentage of the electricity they sell from Class I sources (solar, wind, wave/tidal action, geothermal, methane captured from landfills, fuel cells with certain types of power sources, and biomass) and Class II sources (hydroelectric facilities with a combined design capacity of less than 30 MW, and certain resource recovery facilities). In 2010, the Solar Energy Advancement and Fair Competition Act, (SEAFCA), was signed into law. SEAFCA amended several provisions of EDECA, among them the manner in which suppliers were to comply with the solar portion of the RPS. SEAFCA, beginning in energy year 2011, set out a specific requirement for solar energy generation. The Solar Act of 2012 made further changes effective for energy year 2014 and beyond. The RPS requirement has changed over time. For energy year 2005, suppliers were required to procure 0.74% and 2.5% from Class I and Class II sources, respectively. For the most recently completed energy year 2016, 9.649% was required from Class I renewable sources, 2.5% from Class II renewable sources, and 2.75% from solar energy. As noted above, the RPS applies to each supplier or provider that sells electricity to retail customers in New Jersey. Pursuant to Section 14:4-1.2 of the New Jersey Administrative Code, electric public utilities, such as ACE, that provide electric generation services only for the purpose of providing BGS are not electric power suppliers and so are not subject to the RPS procurement requirements.

Similar to ComEd, PECO, BGE, Pepco, DPL and ACE, 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 on renewable portfolio standards.

Table of Contents

Executive Officers of the Registrants as of February 13, 2017

Exelon

Name	Age	Position	Period
Crane, Christopher M.	58	Chief Executive Officer, Exelon	2012 - Present
		Chairman, ComEd, PECO & BGE	2012 - Present
		Chairman, PHI	2016 - Present
		President, Exelon	2008 - Present
		President, Generation	2008 - 2013
		Chief Operating Officer, Exelon	2008 - 2012
Cornew, Kenneth W.	51	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.	56	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2012 - Present
		Vice Chairman, ComEd, PECO, BGE	2012 - Present
		Vice Chairman, PHI	2016 - Present
		Chief Executive Officer, PECO; Executive Vice President, Exelon	2007 - 2012
		President and Director, PECO	2003 - 2012
Pramaggiore, Anne R.	58	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
Adams, Craig L.	64	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Butler, Calvin G.	47	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
Velazquez, David M.	57	President and Chief Executive Officer, PHI	2016 - Present
		President and Chief Executive Officer, Pepco, DPL and ACE	2009 - Present
		Executive Vice President, Pepco Holdings, Inc.	2009 - 2016
Von Hoene Jr., William A.	63	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
		Executive Vice President, Finance and Legal, Exelon	2009 - 2012
Thayer, Jonathan W.	45	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	54	Executive Vice President and Chief Enterprise Risk Officer, Exelon	2013 - Present
		Managing Director, Gleam Capital Management	2012 - 2013
DesParte, Duane M.	53	Senior Vice President and Corporate Controller, Exelon	2008 - Present

Table of Contents

Generation

Name	Age	Position	Period
Cornew, Kenneth W.	51	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
Pacilio, Michael J.	56	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	
Hanson, Bryan C.	51	President and Chief Nuclear Officer, Exelon Nuclear; Senior Vice President, Exelon Generation	2015 - Present
Nigro, Joseph	52	Executive Vice President, Exelon; Chief Executive Officer, Constellation	2013 - Present
		Senior Vice President, Portfolio Management and Strategy	2012 - 2013
		Vice President, Structuring and Portfolio Management, Exelon Power Team	2010 - 2012
DeGregorio, Ronald	54	Senior Vice President, Generation; President, Exelon Power	2012 - Present
		Chief Integration Officer, Exelon	2011 - 2012
Wright, Bryan P.	50	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
Bauer, Matthew N.	40	Vice President and Controller, Generation	2016 - Present
		Vice President and Controller, BGE	2014 - 2016
		Vice President of Power Finance, Exelon Power	2012 - 2014
		Director, FP&A and Retail, Constellation	2012 - 2012
		Executive Director, Corporate Development, Constellation	2009 - 2012

Table of Contents

ComEd

Name	Age	Position	Period
Pramaggiore, Anne R.	58	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
Donnelly, Terence R.	56	Executive Vice President and Chief Operating Officer, ComEd	2012 - Present
		Executive Vice President, Operations, ComEd	2009 - 2012
Trpik Jr., Joseph R.	47	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 - Present
Jensen, Val	61	Senior Vice President, Customer Operations, ComEd	2012 - Present
		Vice President, Marketing and Environmental Programs, ComEd	2008 - 2012
Gomez, Veronica	47	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2017 - Present
		Vice President and Deputy General Counsel, Litigation, Exelon	2012 - 2017
Marquez Jr., Fidel	55	Senior Vice President, Governmental and External Affairs, ComEd	2012 - Present
		Senior Vice President, Customer Operations, ComEd	2009 - 2012
Brookins, Kevin B.	55	Senior Vice President, Strategy & Administration, ComEd	2012 - Present
		Vice President, Operational Strategy and Business Intelligence, ComEd	2010 - 2012
McGuire, Timothy M.	58	Senior Vice President, Distribution Operations, ComEd	2016 - Present
		Vice President, Transmission and Substations, ComEd	2010 - 2016
Kozel, Gerald J.	44	Vice President, Controller, ComEd	2013 - Present
		Assistant Corporate Controller, Exelon	2012 - 2013
		Director of Financial Reporting and Analysis, Exelon	2009 - 2012

Table of Contents

PECO

Name	Age	Position	Period
Adams, Craig L.	64	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Barnett, Phillip S.	53	Senior Vice President and Chief Financial Officer, PECO	2007 - Present
		Treasurer, PECO	2012 - Present
Innocenzo, Michael A.	51	Senior Vice President and Chief Operations Officer, PECO	2012 - Present
		Vice President, Distribution System Operations and Smart Grid/Smart Meter, PECO	2010 - 2012
Webster Jr., Richard G.	55	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
		Director of Rates and Regulatory Affairs	2007 - 2012
Murphy, Elizabeth A.	57	Senior Vice President, Governmental and External Affairs, PECO	2016 - Present
		Vice President, Governmental and External Affairs, PECO	2012 - 2016
		Director, Governmental & External Affairs, PECO	2007 - 2012
Jiruska, Frank J.	56	Vice President, Customer Operations, PECO	2013 - Present
Diaz Jr., Romulo L.	70	Vice President and General Counsel, PECO	2012 - Present
		Vice President, Governmental and External Affairs, PECO	2009 - 2012
Bailey, Scott A.	40	Vice President and Controller, PECO	2012 - Present
		Assistant Controller, Generation	2011 - 2012

Table of Contents

BGE

Name	Age	Position	Period
Butler, Calvin G.	47	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
Woerner, Stephen J.	49	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
Case, Mark D.	55	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
		Senior Vice President, Strategy and Regulatory Affairs, BGE	2007 - 2012
Biagiotti, Robert D.	47	Vice President, Customer Operations and Chief Customer Officer, BGE	2015 - Present
		Vice President, Gas Distribution, BGE	2011 - 2015
Gahagan, Daniel P.	63	Vice President and General Counsel, BGE	2007 - Present
Vahos, David M.	44	Senior Vice President, Chief Financial Officer and Treasurer, BGE	2016 - Present
		Vice President, Chief Financial Officer and Treasurer, BGE	2014 - 2016
		Vice President and Controller, BGE	2012 - 2014
		Executive Director, Audit, Constellation	2010 - 2012
Holmes, Andrew W.	48	Vice President and Controller, BGE	2016 - Present
		Director, Generation Accounting, Exelon	2013 - 2016
		Director, Derivatives and Technical Accounting, Exelon	2008 - 2013
Núñez, Alexander G.	45	Senior Vice President, Regulatory and External Affairs, BGE	2016 - Present
		Vice President, Governmental and External Affairs, BGE	2013 - 2016
		Director, State Affairs, BGE	2012 - 2013

Table of Contents

PHI, Pepco, DPL and ACE

Name	Age	Position	Period
Velazquez, David M.	57	President and Chief Executive Officer, PHI	2016 - Present
		Executive Vice President, Pepco Holdings, Inc.	2009 - 2016
		President and Chief Executive Officer, Pepco, DPL and ACE	2009 - Present
Anthony, J. Tyler	52	Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL and ACE	2016 - Present
		Senior Vice President, Distribution Operations, ComEd	2010 - 2016
Kinzel, Donna J.	49	Senior Vice President and Chief Financial Officer, PHI, Pepco, DPL and ACE	2016 - Present
		Vice President, Treasurer and Chief Risk Officer, Pepco Holdings	2012 - Present
Bonney, Paul R.	58	Senior Vice President, Legal and Regulatory Strategy, PHI, Pepco, DPL and ACE	2016 - Present
		Senior Vice President and General Counsel, Constellation Energy	2012 - 2016
Parker, Kenneth J.	54	Senior Vice President, Governmental and External Affairs, PHI, Pepco, DPL and ACE	2016 - Present
		Senior Vice President, Government Affairs and Corporate Citizenship, Pepco Holdings, Inc.	2012 - 2016
Stark, Wendy E.	44	Vice President and General Counsel, PHI, Pepco DPL and ACE	2016 - Present
		Deputy General Counsel, Pepco Holdings, Inc.	2012 - Present
McGowan, Kevin M.	55	Vice President, Regulatory Policy and Strategy	2016 - Present
		Vice President, Regulatory Affairs, Pepco Holdings, Inc.	2012 - 2016
Aiken, Robert M.	50	Vice President and Controller, PHI, Pepco, DPL and ACE	2016 - Present
		Vice President and Controller, Generation	2012 - 2016
		Executive Director and Assistant Controller, Constellation	2011 - 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, BGE, and PHI 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.

Table of Contents

Exelon s financial condition and results of operations are affected to a significant degree by: (1) Generation s position as a predominantly nuclear generator selling power into competitive energy markets with a concentration in select regions, and (2) the role of the Utility Registrants as operators of electric transmission and distribution systems in six 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 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 regulation or legislation regarding climate change and renewable portfolio standards, could have significant effects on the Registrants. Also, returns for the Utility Registrants 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 the Utility Registrants 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 PHI Merger. Exelon is subject to additional risks related to the merger with PHI that closed on March 23, 2016.

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 of spot and forward market prices in the markets in which it operates rise and fall.

Price of Fuels: The spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Thus, the market price of power is affected by the market price of the marginal fuel used to generate the electricity unit. Often, the next unit of electricity will be supplied from generating stations fueled by fossil fuels. Consequently, changes in the market price of fossil fuels often result in comparable changes to the market price of power. For example, the use of new technologies to recover natural gas from shale deposits has increased natural gas supply and reserves, placing downward pressure on natural gas prices and, therefore, on power prices. The continued addition of supply from new alternative generation resources, such as wind and solar, whether mandated through RPS or otherwise subsidized or encouraged through climate legislation or regulation, could 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 related 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 position. See Note 9 Early Nuclear 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 vary from region to region with distinct 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. (All Registrants)

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 position 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. (All Registrants)

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

44

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 the Utility Registrants customers, the results of operations and financial position of the Utility Registrants 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 position 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 position. (All Registrants)

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 depends 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, 2016, approximately 23%, or $2.2 billion of the Registrants available credit facilities were with European banks. The credit facilities include $9.5 billion in aggregate total commitments of which $7.9 billion was available as of December 31, 2016. As of December 31, 2016, there was $75 million of borrowings under Generation s bilateral credit facilities. 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 could 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 counterparties, it would be required to provide significant amounts of collateral under its agreements with counterparties and could experience higher borrowing costs. (All Registrants)

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 could have a material adverse effect upon its liquidity. The amount of collateral required to be provided by Generation at any point in time depends 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.

The Utility Registrants operating agreements with PJM and PECO s, BGE s and DPL 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 the Utility Registrants 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, BGE and DPL, 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 the Utility Registrants were downgraded, they could experience higher borrowing costs as a result of the downgrade.

A Utility Registrant could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the utility industry in general, or a Utility Registrant in particular, has deteriorated. A Utility Registrant could experience a downgrade if its current regulatory environment becomes less predictable by materially lowering returns for the Utility Registrant or adopting other measures to limit utility rates. Additionally, the ratings for a Utility Registrant could be downgraded if its financial results are weakened from current levels due to weaker operating performance or due to a failure to properly manage its capital structure. In addition, changes in ratings methodologies by the agencies could also have a negative impact on the ratings of the Utility Registrants.

The Utility Registrants conduct their respective businesses and operate under governance models and other arrangements and procedures intended to assure that the Utility Registrants are treated as separate, independent companies, distinct from Exelon and other Exelon subsidiaries in order to isolate the Utility Registrants 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-

46

fencing) could help avoid or limit a downgrade in the credit ratings of the Utility Registrants in the event of a reduction in the credit rating of Exelon. Despite these ring-fencing measures, the credit ratings of the Utility Registrants 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 some or all of the Utility Registrants. A reduction in the credit rating of a Utility Registrant could have a material adverse effect on the Utility Registrant.

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 most of 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 position.

Generation buys and sells energy and other products and enters into financial contracts to manage risk and hedge various positions in Generation s power generation portfolio. Generation is exposed to volatility in financial results for unhedged positions.

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 the Utility Registrants 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.

Table of Contents

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. (All Registrants)

Potential Corporate Tax Reform. The results of the November 2016 U.S. elections have introduced greater uncertainty with respect to federal tax policies. President Trump has stated that one of his top priorities is comprehensive tax reform and House Republicans plan to advance their tax reform blueprint . Tax reform proposals call for a reduction in the corporate federal income tax rate from the current 35% to as low as 15%. Other proposals provide, among other items, for the immediate deduction of capital investment expenditures and full or partial elimination of debt interest expense deductions. It is uncertain whether, to what extent or when these or any other changes in federal tax policies will be enacted or the transition time frame for such changes. Further, for the Utility Registrants, regulators may impose rate reductions to provide the benefit of any income tax expense reductions to customers and refund excess deferred income taxes previously collected through rates. The amounts and timing of any such rate changes would be subject to the discretion of the rate regulator in each specific jurisdiction. For these reasons, the Registrants cannot predict the impact any potential changes may have on their future results of operations, cash flows or financial position, and such changes could be material.

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 established 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 and the Utility Registrants results from operations or cash flows. (All Registrants)

The Utility Registrants current procurement plans include purchasing power through contracted suppliers and in the spot market. ComEd s, PECO s and ACE s costs of purchased power are charged to customers without a return or profit component. BGE s, Pepco s and DPL s SOS rates charged to customers recover their wholesale power supply costs and include a return component. For PECO, purchased natural gas costs are charged to customers with no return or profit component. For BGE, purchased natural gas costs are charged to customers using a MBR mechanism that compares the actual cost of gas to a market index. The difference between the actual cost and the market index is shared equally between shareholders and customers. For DPL, purchased natural gas costs are charged to customers using a GCR mechanism that compares the actual cost of gas to a forecasted amount. The difference between the actual cost and the forecast is fully recoverable and carried forward as a recovery balance in the next GCR filing. 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 the Utility Registrants. In addition, any challenges by the regulators or the Utility Registrants as to the recoverability of these costs could have a material effect on the Registrants results of operations or cash flows. Also, the Utility Registrants 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 the Utility Registrants customers, such as unemployment for residential customers and less demand for products and services provided by

48

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 the Utility Registrants results of operations or cash flows. Generation s customer-facing energy delivery activities face similar economic downturn risks, such as lower volumes sold and increased expense for uncollectible customer balances which 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. (All Registrants)

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, PECO, DPL and ACE. Due to revenue decoupling, BGE, Pepco and DPL recognize revenues at MDPSC and DCPSC-approved levels per customer, regardless of what actual distribution volumes are for a billing period, and are not affected by actual weather with the exception of major storms. Pursuant to the Illinois FEJA signed into law on December 2016 and effective in 2017, ComEd can eliminate the favorable or unfavorable impacts of weather or load on its electric distribution revenues by either (1) revising its electric distribution formula rate to eliminate the ROE collar beginning with the reconciliation performed for the 2017 calendar year or (2) implementing a decoupling tariff if the electric distribution formula rate were to be terminated at anytime.

Extreme weather conditions or damage resulting from storms could stress the Utility Registrants 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 the Utility Registrants 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.

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. (All Registrants)

Long-lived assets represent the single largest asset class on the Registrants statements of financial position. Specifically, long-lived assets account for 62%, 54%, 68%, 70%, 81%, 76%, 79% and 73% of total assets for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE, respectively, as of December 31, 2016. In addition, Exelon and Generation have significant balances related to unamortized energy contracts, as further disclosed in Note 11 Intangible Assets of the Combined Notes to Consolidated Financial Statements. 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 to fair value 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.

As of December 31, 2016, Exelon s $6.7 billion carrying amount of goodwill primarily consists of $2.6 billion at ComEd relating to the acquisition of ComEd in 2000 upon the formation of Exelon and $4.0 billion at PHI primarily resulting from Exelon s acquisition of PHI in the first quarter of 2016. 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. Such an impairment would result in a non-cash charge to expense, which could have a material adverse impact on Exelon s, ComEd s, and PHI s results of operations.

Regulatory actions or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd s, Pepco s, DPL s, and ACE s business, and the fair value of debt, could potentially result in future impairments of Exelon s, PHI s, and ComEd s goodwill, which could be material.

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.

Exelon and its subsidiaries at times guarantee the performance of third parties, which could result in substantial costs in the event of non-performance by such third parties. In addition, the Registrants could 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. The Registrants could also incur substantial costs in the event that third parties are entitled to indemnification related to environmental or other risks in connection with the acquisition and divestiture of assets. (All Registrants)

Some of the Registrants have issued guarantees of the performance of third parties, which obligate the Registrant or its subsidiaries to perform in the event that the third parties do not perform. In the event of non-performance by those third parties, a Registrant could incur substantial cost to fulfill its obligations under these guarantees. Such performance guarantees could have a material impact on the operating results, financial condition, or cash flows of the Registrant. Some of the Registrants have issued indemnities to third parties regarding environmental or other matters in connection with purchases and sales of asset and a Registrant could incur substantial costs to fulfill its obligations under these indemnities.

Some of 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 position. In connection with Exelon s 2001 corporate restructuring, Generation assumed certain of ComEd s and PECO s rights and obligations with respect to their former generation businesses. Further, ComEd and PECO may have entered into agreements with third parties under which the third-party agreed to indemnify ComEd or PECO for certain obligations related to their respective former generation businesses that have been assumed by Generation as part of the restructuring. If the third-party or Generation experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, ComEd or PECO could be liable for any existing or future claims, which could impact ComEd s or PECO s results of operations, cash flows or financial position.

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. (All Registrants)

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 significantly affected by Generation s sale of power at market-based rates, as opposed to cost-based or other similarly regulated rates, and Exelon s and the Utility Registrants operating results and cash flows are heavily dependent on the ability of the Utility Registrants to recover their costs for the retail purchase and distribution of power to their customers. Similarly, there is risk that financial market regulations could increase the Registrants compliance costs and limit their ability to engage in certain transactions. In the planning and management of operations, the Registrants must address the effects of regulation on their businesses and changes in the regulatory framework, including initiatives by Federal and state legislatures, RTOs, exchanges, ratemaking agencies and taxing authorities. Additionally, the Registrants need to be cognizant 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 respective results of operations, cash flows or financial position.

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 position. 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, could 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 could 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.

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 rulemaking proceedings 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

52

Table of Contents

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 could impact its cash flows or financial position, but such impacts could be material.

The Utility Registrants could also be subject to some Dodd-Frank requirements to the extent they were to enter into swaps. However, at this time, management of the Utility Registrants continue to expect that their companies will not be materially affected by Dodd-Frank.

Generation s affiliation with the Utility Registrants, together with the presence of a substantial percentage of Generation s physical asset base within the Utility Registrants service territories, could increase Generation s cost of doing business to the extent future complaints or challenges regarding the Utility Registrants 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 the Utility Registrants 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 the Utility Registrants 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 could question or challenge costs and transactions incurred by the Utility Registrants with Generation, irrespective of any previous regulatory processes or approvals underlying those transactions. The prospect of such challenges could increase the time, complexity and cost of the associated regulatory proceedings, and the occurrence of such challenges could 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. (All Registrants)

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 could 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 July 28, 2016, the NJDEP issued a final permit for Salem that did not require the installation of cooling towers. However, the permit is being challenged by an environmental organization, and if successful, could result in additional costs for Clean Water Act compliance.

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 could be limited by the financial resources of the transferee. See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Changes in the Utility Registrants 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 and the Utility Registrants)

The Utility Registrants 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 a Utility Registrant 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, the Utility Registrants could agree to negotiated settlements related to various rate matters, customer initiatives or franchise agreements. These settlements are subject to regulatory approval.

The Utility Registrants cannot predict the ultimate outcomes of any settlements or the actions by Illinois, Pennsylvania, Maryland, the District of Columbia, Delaware, New Jersey 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 the Utility Registrants 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, SOS, and BGS, 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 the Utility Registrants, as applicable, to recover their costs and could have a material adverse effect on the Utility Registrants 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 and the Utility Registrants. (All Registrants)

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 and the Utility Registrants, especially if timely cost recovery is not allowed for Utility Registrants. 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 the Utility Registrants 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, Generation and the Utility Registrants. 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 and the Utility Registrants. (Exelon and the Utility Registrants)

As of December 31, 2016, Exelon and the Utility Registrants have concluded that the operations of the Utility Registrants 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, and the Utility Registrants 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 and the Utility Registrants. At December 31, 2016, the gain (loss) could have been as much as $2.5 billion, $(1.1) billion, $(552) million, $(821) million, $(208) million and $(476) million (before taxes) as a result of the elimination of regulatory assets and liabilities of ComEd, PECO, BGE, Pepco, DPL and ACE, respectively. Further, Exelon would record a charge against OCI (before taxes) of up to $2.6 billion, $614 million, $424 million, $243 million, and $84 million for ComEd, BGE, Pepco, DPL and ACE 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 impairment of ComEd s or PHI s goodwill, which could be significant and at least partially offset the gains at ComEd discussed above. A significant decrease in equity as a result of any changes could limit the ability of the Utility Registrants 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 and PHI s goodwill, respectively.

Table of Contents

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 could incur costs either to limit further the GHG emissions from their operations or to procure emission allowance credits. For example, more stringent permitting requirements could 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 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

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

As a result of the Energy Policy Act of 2005, users, owners and operators of the bulk power transmission system, including Generation and the Utility Registrants, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. As operators of natural gas distribution systems, PECO, BGE, and DPL 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, MDPSC, DCPSC, DPSC and NJBPU impose certain distribution reliability standards on the Utility Registrants. 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.

The Utility Registrants 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 the Utility Registrants to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards.

See Note 3 Regulatory Matters and Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants could be subject to adverse publicity and reputational risks, which make them vulnerable to negative customer perception and could lead to increased regulatory oversight or other consequences. (All Registrants)

The Registrants have large consumer customer bases and as a result could be the subject of public criticism focused on the operability of their assets and infrastructure and quality of their service. Adverse publicity of this nature could render legislatures and other governing bodies, public service commissions and other regulatory authorities, and government officials less likely to view energy companies such as Exelon and its subsidiaries in a favorable light, and could cause Exelon and its

subsidiaries to be susceptible to less favorable legislative and regulatory outcomes, as well as increased regulatory oversight and more stringent regulatory requirements. Unfavorable regulatory outcomes can include the enactment of more stringent laws and regulations governing Exelon s operations, as well as fines, penalties or other sanctions or requirements. The imposition of any of the foregoing could have a material negative impact on the Registrants business, results of operations, cash flows and financial positions.

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 position. (All Registrants)

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 24 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 position. 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 SNF at nuclear power plants for up to 60 years beyond the original and renewed licensed operating life of the plants.

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. This fee was discontinued 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 2030 to be the earliest date when the DOE will begin accepting SNF, which could be delayed by further regulatory action. See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on the SNF 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.

Table of Contents

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. (All Registrants)

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 some risk for serious injury, including loss of life. These 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, their ability to raise capital and their future growth. (All Registrants)

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

Natural disasters and other significant events increase the risk to Generation that the NRC or other regulatory or legislative bodies could change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological matters. 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 could adversely affect the Registrants operations and their ability to raise capital.

The impact that potential terrorist attacks could have on the industry in general and on Exelon in particular is uncertain. 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 could result in a decline in energy consumption, which could 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 could 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 Exelon s generating and transmission and distribution assets could be affected, resulting in decreased service levels and increased costs.

Table of Contents

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 the Utility Registrants. 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. 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 position. In addition, closure of generating plants owned by others, or extended interruptions of generating plants or failure of transmission lines, could affect transmission systems that could adversely affect the sale and delivery of electricity in markets served by Generation.

Nuclear major incident risk. Although the safety record of nuclear reactors generally has been very good, accidents and other unforeseen problems have occurred both in the United States and abroad. The consequences of a major incident 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 position. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, whether owned Generation or others, could result in increased regulation and reduced public support for nuclear-fueled energy and significantly affect Generation s results of operations or financial position.

Nuclear insurance. As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance. The required amount of nuclear liability insurance is $450 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 $13.4 billion limit for a single incident.

Generation is a member of an industry mutual insurance company, NEIL, which provides property and business interruption insurance for Generation s nuclear operations. In previous years, NEIL has made distributions to its members but Generation cannot predict the level of future distributions or if they will occur at all. See Note 24 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 could 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 position could be significantly affected. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Ultimately, if the investments held by Generation s NDTs are not sufficient to fund the decommissioning of Generation s nuclear units, Generation could 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 position 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.

For nuclear units that are subject to regulatory agreements with either the ICC or the PAPUC, decommissioning-related activities are generally offset within Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd and PECO have recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability.

In the case of the nuclear units subject to the regulatory agreements with the ICC, if the funds held in the NDT funds for any former ComEd unit are expected to not exceed the total decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to Exelon s and Generation s results of operations and financial position could be material. Additionally, any remaining balances in noncurrent payables to affiliates at Generation and ComEd s noncurrent affiliate receivable from Generation and corresponding regulatory liability may need to be reversed and could have a material impact on Generation s Consolidated Statement of Operations and Comprehensive Income.

In the case of the nuclear units subject to the regulatory agreements with the PAPUC, any changes to the PECO regulatory agreements could impact Exelon s and Generation s ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon s and Generation s results of operations and financial position could be material. Additionally, any remaining balances in noncurrent payables to affiliates at Generation and PECO s noncurrent affiliate receivable from Generation and corresponding regulatory liability may need to be reversed and could have a material impact on Generation s Consolidated Statement of Operations and Comprehensive Income.

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 Muddy Run Pumped Storage Project expires on December 1, 2055. The license for the Conowingo Hydroelectric Project expired September 1, 2014. FERC issued an annual license, effective as of the expiration of the previous license. If FERC does not issue a license prior to the expiration of the annual license, the annual license will renew automatically. 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 position. 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.

Table of Contents

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. (All Registrants)

The Registrants businesses are capital intensive and require significant investments by Generation in electric generating facilities and by the Utility Registrants in transmission and 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 respective results of operations, financial condition, or cash flows could be adversely affected if they were unable to effectively manage their capital projects or raise the necessary capital. Furthermore, operational failure of electric or gas systems or infrastructure could result in potential liability if such failure results in damage to property or injury to individuals. See ITEM 1. BUSINESS for further information regarding the Registrants potential future capital expenditures.

The Utility Registrants operating costs, and customers and regulators opinions of the Utility Registrants are affected by their ability to maintain the availability and reliability of their delivery and operational systems. (Exelon and the Utility Registrants)

Failures of the equipment or facilities, including information systems, used in the Utility Registrants 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 the Utility Registrants service territory fail to perform as intended or are not successfully integrated with billing and other information systems, the Utility Registrants results of operations, cash flows or financial condition could be negatively impacted. Furthermore, if any of the financial, accounting, or other data processing systems fail or have other significant shortcomings, the Utility Registrants 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, the Utility Registrants financial results could also be negatively impacted. In addition, dependence upon automated systems could 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 the Utility Registrants 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 24 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.

The Utility Registrants respective ability to deliver electricity, their operating costs and their capital expenditures could be negatively impacted by transmission congestion and failures of neighboring transmission systems. (All Registrants)

Demand for electricity within the Utility Registrants service areas could stress available transmission capacity requiring alternative routing or curtailment of electricity usage with consequent

Table of Contents

effects on operating costs, revenues and results of operations. Also, insufficient availability of electric supply to meet customer demand could jeopardize the Utility Registrants 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 the Utility Registrant s to upgrade or expand their respective transmission systems through additional capital expenditures.

The electricity transmission facilities of the Utility Registrants are interconnected with the transmission facilities of neighboring utilities and are part of the interstate power transmission grid that is operated by PJM RTO. Although PJM s systems and operations are designed to ensure the reliable operation of the transmission grid and prevent the operations of one utility from having an adverse impact on the operations of the other utilities, there can be no assurance that service interruptions at other utilities will not cause interruptions in the Utility Registrants service areas. If the Utility Registrants were to suffer such a service interruption, it could have a negative impact on their and Exelon s results of operations, cash flows and financial position.

The Registrants are subject to physical security and cybersecurity risks. (All Registrants)

The Registrants face physical security and cybersecurity risks as the owner-operators of generation, transmission and distribution facilities and as participants 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 critical infrastructure information, sensitive customer, vendor and employee data, 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, the Registrants may be unable to prevent all such attacks in the future. If a significant breach were to occur, the reputation of Exelon and its customer supply activities could be adversely affected, customer confidence in the Registrants or others in the industry could be diminished, or Exelon and its subsidiaries could be subject to legal claims, any of which could 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 maintained against losses resulting from any such events or security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result. The Utility Registrants deployment of smart meters throughout their service territories could 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. (All Registrants)

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. (All Registrants)

Generation could continue to pursue growth in its existing businesses and markets and further diversification across the competitive energy value chain. This could include investment opportunities in renewables, development of natural gas generation, distributed generation, potential expansion of the existing 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.

The Utility Registrants 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 the Utility Registrants financial results.

Risks Related to the PHI Merger

The merger may not achieve its anticipated results, and Exelon could be unable to integrate the operations of PHI in the manner expected. (Exelon)

Exelon and PHI entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Exelon and PHI can be integrated in an efficient, effective and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of Exelon s businesses, processes and systems or inconsistencies in standards, controls, procedures, practices and policies, any of which could adversely affect the combined company s ability to achieve the anticipated benefits of the merger as and when expected. Exelon could have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve these anticipated benefits could result in increased costs and could adversely affect Exelon s future business, financial condition, operating results and prospects.

The merger may not be accretive to earnings and could cause dilution to Exelon s earnings per share, which could negatively affect the market price of Exelon s common stock. (Exelon)

The timing and amount of accretion expected could be significantly adversely affected by a number of uncertainties, including market conditions, risks related to Exelon s businesses and whether

64

Table of Contents

the business of PHI is integrated in an efficient and effective manner. Exelon also could encounter additional transaction and integration-related costs, could fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect preliminary estimates. Any of these factors could cause a decrease in Exelon s adjusted earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of Exelon s common stock.

Exelon could incur unexpected transaction fees and merger-related costs in connection with the merger. (Exelon, PHI, Pepco, DPL and ACE)

Exelon is incurring costs to combine the operations of Exelon, PHI and its subsidiaries. Exelon and PHI could incur additional unanticipated costs in the integration of the businesses of the two companies. Although Exelon and PHI expect that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction and merger-related costs over time, the combined company may not achieve this net benefit in the near term, or at all.

Exelon could encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals for the PHI Merger. (Exelon, PHI, Pepco, DPL and ACE)

As a result of the process to obtain regulatory approvals required for the PHI Merger, Exelon is committed to various programs, contributions and investments in several settlement agreements and regulatory approval orders, one of which may remain subject to the most favored nation reconciliation process. It is possible that Exelon could encounter delays, unexpected difficulties, or additional costs in meeting these commitments in compliance with the terms of the relevant agreements and orders. Failure to fulfill the commitments in accordance with their terms could result in increased costs or result in penalties or fines that could adversely affect Exelon s, PHI s, Pepco s, DPL s and ACE s financial position and operating results.

ITEM 1B. UNRESOLVED STAFF COMMENTS
All Registrants

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, 2016:

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	2,383
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)]
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)]
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
Southeast Chicago	Midwest	Chicago, IL	8		Gas	Peaking	296
Clinton Battery Storage	Midwest	Blanchester, OH	1		Energy Storage	Peaking	10
Total Midwest							12,150
Limerick	Mid-Atlantic	Sanatoga, PA	2		Uranium	Base-load	2,317
Peach Bottom	Mid-Atlantic	Delta, PA	2	50	Uranium	Base-load	1,301[(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	879[(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	16	Solar	Base-load	28
Solar New Jersey 1	Mid-Atlantic	Various, NJ	6	Solar	Base-load	18
Solar Horizons	Mid-Atlantic	Emmitsburg, MD	1	Solar	Base-load	16
Solar New Jersey 2	Mid-Atlantic	Various, NJ	2	Solar	Base-load	11
Solar Maryland	Mid-Atlantic	Various, MD	10	Solar	Base-load	9
Solar Maryland 2	Mid-Atlantic	Various, MD	3	Solar	Base-load	8
Solar Federal	Mid-Atlantic	Trenton, NJ	1	Solar	Base-load	5
Solar New Jersey 3	Mid-Atlantic	Middle Township, NJ	5	Solar	Base-load	2
Solar DC	Mid-Atlantic	District of Columbia	1	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	5	Oil/Gas	Peaking	412
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	117
Westport	Mid-Atlantic	Baltimore, MD	1	Gas	Peaking	116
Richmond	Mid-Atlantic	Philadelphia, PA	2	Oil	Peaking	98
Gould Street	Mid-Atlantic	Baltimore, MD	1	Gas	Peaking	97

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)]
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
Riverside	Mid-Atlantic	Baltimore, MD	2		Oil/Gas	Peaking	39
Chester	Mid-Atlantic	Chester, PA	3		Oil	Peaking	39
Schuylkill	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	30
Salem	Mid-Atlantic	Lower Alloways Creek Twp, NJ	1	42.59	Oil	Peaking	16[(f)]
Pennsbury	Mid-Atlantic	Morrisville, PA	2		Landfill Gas	Peaking	6
Total Mid-Atlantic							11,624
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	705
Mountain Creek 8	ERCOT	Dallas, TX	1		Gas	Intermediate	568
Colorado Bend	ERCOT	Wharton, TX	6		Gas	Intermediate	468
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							3,567
Solar Massachusetts	New England	Various, MA	11		Solar	Base-load	5
Holyoke Solar	New England	Various, MA	2		Solar	Base-load	5
Solar Net Metering	New England	Uxbridge, MA	1		Solar	Base-load	2
Solar Connecticut	New England	Various, CT	3		Solar	Base-load	2
Mystic 8, 9	New England	Charlestown, MA	6		Gas	Intermediate	1,415
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	124
Framingham	New England	Framingham, MA	3		Oil	Peaking	31
Mystic Jet	New England	Charlestown, MA	1		Oil	Peaking	9
Total New England							2,204
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	3

Total New York							1,129
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
Bluestem	Other	Beaver County, OK	60	29	Wind	Base-load	57
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
Solar Arizona	Other	Various, AZ	127		Solar	Base-load	46
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)
Sacramento PV Energy	Other	Sacramento, CA	4		Solar	Base-load	30
Cassia	Other	Buhl, ID	14		Wind	Base-load	29
Wildcat	Other	Lovington, NM	13		Wind	Base-load	27
Sunnyside	Other	Sunnyside, UT	1	50	Waste Coal	Base-load	26(f)(h)
Solar Arizona 2	Other	Various, AZ	25		Solar	Base-load	23

67

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]
California PV Energy	Other	Various, CA	53		Solar	Base-load	21
Echo 2	Other	Echo, OR	10		Wind	Base-load	20
Tuana Springs	Other	Hagerman, ID	8		Wind	Base-load	17
Greensburg	Other	Greensburg, KS	10		Wind	Base-load	13
Echo 3	Other	Echo, OR	6	99	Wind	Base-load	10[f]
Exelon Wind 1	Other	Gruver, TX	8		Wind	Base-load	10[i]
Exelon Wind 2	Other	Gruver, TX	8		Wind	Base-load	10[i]
Exelon Wind 3	Other	Gruver, TX	8		Wind	Base-load	10[i]
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
California PV Energy 2	Other	Various, CA	31		Solar	Base-load	9
Solar Georgia	Other	Various, GA	10		Solar	Base-load	8
Outback Solar	Other	Christmas Valley, OR	1		Solar	Base-load	6
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
Solar California	Other	Various, CA	4		Solar	Base-load	3
Solar Georgia 2	Other	Various, GA	1		Solar	Base-load	1
Hillabee	Other	Alexander City, AL	3		Gas	Intermediate	753
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							2,046
Total							32,720

(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 November 30, 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.
(h) Generation sold its 50% interest in Sunnyside effective February 3, 2017
(i) Generation plans to retire and cease generation operations at the Exelon Wind 1, Exelon Wind 2 and Exelon Wind 3 units effective June 1, 2017.

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

Generation maintains property insurance against loss or damage to its principal plants and properties by fire or other perils, subject to certain exceptions. For additional information regarding nuclear insurance of generating facilities, see ITEM 1. BUSINESS 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, 2016 were as follows:

Voltage (Volts)	Circuit Miles
765,000	90
345,000	2,658
138,000	2,208

ComEd s electric distribution system includes 35,397 circuit miles of overhead lines and 31,049 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, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	188 [a]
230,000	549

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 12,963 circuit miles of overhead lines and 9,290 circuit miles of underground lines.

Gas

The following table sets forth PECO s natural gas pipeline miles at December 31, 2016:

	Pipeline Miles
Transmission	30
Distribution	6,871
Service piping	6,273
Total	13,174

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, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	218
230,000	331

138,000	55
115,000	709

BGE s electric distribution system includes 9,443 circuit miles of overhead lines and 17,306 circuit miles of underground lines.

Table of Contents

Gas

The following table sets forth BGE s natural gas pipeline miles at December 31, 2016:

	Pipeline Miles
Transmission	161
Distribution	7,239
Service piping	6,230
Total	13,630

BGE has an LNG facility located in Baltimore, Maryland that has a storage capacity of 1,056 mmcf and a send-out capacity of 332 mmcf/day and a propane-air plant located in Baltimore, Maryland, with a storage capacity of 550 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.

Pepco

Pepco s electric substations and a significant portion of its transmission lines are located on property that Pepco 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. Pepco 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

Pepco s high voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	142
230,000	774
138,000	60
115,000	38

Pepco s electric distribution system includes approximately 4,100 circuit miles of overhead lines and 6,800 circuit miles of underground lines. Pepco also operates a distribution system control center in Bethesda, Maryland. The computer equipment and systems contained in Pepco s control center are financed through a sale and leaseback transaction.

First Mortgage and Insurance

The principal properties of Pepco are subject to the lien of Pepco s mortgage dated July 1, 1935, as amended and supplemented, under which Pepco First Mortgage Bonds are issued.

Table of Contents

Pepco maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, Pepco 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 Pepco.

DPL

DPL s electric substations and a significant portion of its transmission lines are located on property that DPL 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. DPL 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

DPL s high voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	16
230,000	470
138,000	557
69,000	576

DPL s electric distribution system includes approximately 6,100 circuit miles of overhead lines and 6,100 circuit miles of underground lines. DPL also owns and operates a distribution system control center in New Castle, Delaware.

Gas

The following table sets forth DPL s natural gas pipeline miles at December 31, 2016 :

	Pipeline Miles
Transmission [(a)]	7
Distribution	2,036
Service Piping	1,385
Total	3,428

(a) DPL has a 10% undivided interest in approximately 7 miles of natural gas transmission mains located in Delaware which are used by DPL for its natural gas operations and by 90% owner for distribution of natural gas to its electric generating facilities.

DPL owns a liquefied natural gas facility located in Wilmington, Delaware, with a storage capacity of approximately 3,045 mmcf and an emergency sendout capability of 36,000 Mcf per day. DPL owns 4 natural gas city gate stations at various locations in New Castle County, Delaware. These stations have a total primary delivery point contractual entitlement of 158,485 Mcf per day.

First Mortgage and Insurance

The principal properties of PDL are subject to the lien of DPL s mortgage dated October 1, 1947, as amended and supplemented, under which DPL First Mortgage Bonds are issued.

Table of Contents

DPL maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, DPL 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 DPL.

ACE

ACE s electric substations and a significant portion of its transmission lines are located on property that ACE 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. ACE 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

ACE s high voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	281
230,000	234
138,000	268
69,000	652

ACE s electric distribution system includes approximately 7,400 circuit miles of overhead lines and 2,900 circuit miles of underground lines. ACE also owns and operates a distribution system control center in Mays Landing, New Jersey.

First Mortgage and Insurance

The principal properties of ACE are subject to the lien of ACE s mortgage dated January 15, 1937, as amended and supplemented, under which ACE First Mortgage Bonds are issued.

ACE maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, ACE 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 ACE.

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.

73

Table of Contents

ITEM 3. LEGAL PROCEEDINGS
All Registrants

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 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES
All Registrants

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, 2017, there were 926,589,614 shares of common stock outstanding and approximately 113,308 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:

	2016				2015			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 36.36	$ 37.70	$ 36.37	$ 35.95	$ 31.37	$ 34.44	$ 34.98	$ 38.25
Low price	29.82	32.86	33.18	26.26	25.09	28.41	31.28	31.71
Close	35.49	33.29	36.36	35.86	27.77	29.70	31.42	33.61
Dividends	0.318	0.318	0.318	0.310	0.310	0.310	0.310	0.310

Table of Contents

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 2012 through 2016.

This performance chart assumes:

$100 invested on December 31, 2011 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,					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Exelon Corporation	$100	$70.69	$65.11	$88.14	$66.01	$84.36
S&P 500	$100	$111.68	$144.74	$161.22	$160.05	$175.31
S&P Utilities	$100	$98.78	$107.43	$133.52	$122.32	$137.24

Generation

As of January 31, 2017, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2017, there were 127,017,157 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, 2017, 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.

PECO

As of January 31, 2017, 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, 2017, there were 1,000 outstanding shares of common stock, without par value, of BGE, all of which were indirectly held by Exelon.

PHI

As of January 31, 2017, Exelon indirectly held the entire membership interest in PHI.

Pepco

As of January 31, 2017, there were 100 outstanding shares of common stock, $0.01 par value, of Pepco, all of which were indirectly held by Exelon.

DPL

As of January 31, 2017, there were 1,000 outstanding shares of common stock, $2.25 par value, of DPL, all of which were indirectly held by Exelon.

ACE

As of January 31, 2017, there were 8,546,017 outstanding shares of common stock, $3.00 par value, of ACE, all of which were indirectly held by Exelon.

All Registrants

Dividends

Under applicable Federal law, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Generation, ComEd, PECO, BGE, PHI, Pepco, DPL or ACE may limit the dividends that these companies can distribute to Exelon.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account. What constitutes funds properly included in capital account is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon s actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, [its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves, or unless it has specific authorization from the ICC. ComEd has also agreed in connection with a financing arranged through ComEd Financing III that ComEd will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued. No such event has occurred.

PECO has agreed in connection with financings arranged through PEC L.P. and PECO Trust IV that PECO will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued. No such event has occurred.

BGE is subject to certain dividend restrictions established by the MDPSC. First, in connection with the Constellation merger, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE s equity ratio would be below 48% as calculated pursuant to the MDPSC s ratemaking precedents or (b) BGE s senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid and notify the MDPSC that BGE s equity ratio is at least 48% within five business days after dividend payment. There are no other limitations on BGE paying common stock dividends unless BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid.

Pepco is subject to certain dividend restrictions limits imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends, and (ii) the prior rights of holders of future preferred stock, if any, and existing and future mortgage bonds and other long-term debt issued by Pepco and any other restrictions imposed in connection with the incurrence of liabilities.

DPL is subject to certain dividend restrictions imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends, and (ii) the prior rights of holders of existing and future preferred stock, mortgage bonds and other long-term debt issued by DPL and any other restrictions imposed in connection with the incurrence of liabilities.

ACE is subject to dividend restrictions imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends and the regulatory requirement that ACE obtain the prior approval of the NJBPU before dividends can be paid if its equity as a percent of its total capitalization, excluding securitization debt, falls below 30%; (ii) the prior rights of holders of existing and future preferred stock, mortgage bonds and other long-term debt issued by ACE and any other restrictions imposed in connection with the incurrence of liabilities; and (iii) certain provisions of the charter of ACE which impose restrictions on payment of common stock dividends for the benefit of preferred stockholders. Currently, the restriction in the ACE charter does not limit its ability to pay common stock dividends.

Exelon s Board of Directors has approved a dividend policy providing a raise of 2.5% each year for three years, beginning with the June 2016 dividend.

At December 31, 2016, Exelon had retained earnings of $12,030 million, including Generation s undistributed earnings of $2,275 million, ComEd s retained earnings of $987 million consisting of retained earnings appropriated for future dividends of $2,626 million, partially offset by $(1,639) million of unappropriated accumulated deficits, PECO s retained earnings of $941 million, BGE s retained earnings of $1,427 million, and PHI s undistributed earnings of $(61)

million.

Table of Contents

The following table sets forth Exelon s quarterly cash dividends per share paid during 2016 and 2015:

	2016				2015			
	4th	3rd	2nd	1st	4th	3rd	2nd	1st
(per share)	Quarter	Quarter	Quarter	Quarter	Quarter	Quarter	Quarter	Quarter
Exelon	$ 0.318	$ 0.318	$ 0.318	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310

The following table sets forth Generation s and PHI s quarterly distributions and ComEd s, PECO s, Pepco s, DPL s and ACE s quarterly common dividend payments:

	2016				2015			
	4th	3rd	2nd	1st	4th	3rd	2nd	1st
(in millions)	Quarter	Quarter	Quarter	Quarter	Quarter	Quarter	Quarter	Quarter
Generation	$ 755	$ 56	$ 56	$ 55	$ 106	$ 106	$ 906	$ 1,356
ComEd	94	92	92	91	73	76	75	75
PECO	69	69	70	69	70	70	69	70
BGE	45	44	45	45	42	39	41	36
PHI	99	50	16	108	69	69	69	68
Pepco	44	37	16	39	55	60	31	
DPL	15	1		38	12	18		62
ACE	39	13		11				12

First Quarter 2017 Dividend. On January 31, 2017, the Exelon Board of Directors declared a first quarter 2017 regular quarterly dividend of $0.3275 per share on Exelon s common stock payable on March 10, 2017, to shareholders of record of Exelon at the end of the day on February 15, 2017.

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)	**2016 [(a)]**	**2015**	**2014 [(b)]**	**2013**	**2012 [(c)]**
Statement of Operations data:					
Operating revenues	$ 31,360	$ 29,447	$ 27,429	$ 24,888	$ 23,489
Operating income	3,112	4,409	3,096	3,669	2,373
Net income	1,204	2,250	1,820	1,729	1,171
Net income attributable to common shareholders	1,134	2,269	1,623	1,719	1,160
Earnings per average common share (diluted):					
Net income	$ 1.22	$ 2.54	$ 1.88	$ 2.00	$ 1.42
Dividends per common share	$ 1.26	$ 1.24	$ 1.24	$ 1.46	$ 2.10

(a) The 2016 financial results include the activity of PHI from the merger effective date of March 24, 2016 through December 31, 2016.
(b) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 financial results include CENG s results of operations on a fully consolidated basis.
(c) The 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)	**2016**	**2015**	**2014**	**2013**	**2012**
Balance Sheet data:					
Current assets	$ 12,412	$ 15,334	$ 11,853	$ 9,562	$ 10,009
Property, plant and equipment, net	71,555	57,439	52,170	47,330	45,186
Total assets	114,904	95,384	86,416	79,243	78,350
Current liabilities	13,457	9,118	8,762	7,686	7,734
Long-term debt, including long-term debt to financing trusts	32,216	24,286	19,853	18,165	18,266
Preferred securities of subsidiary					87
Shareholders equity	25,837	25,793	22,608	22,732	21,431

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)	**2016**	**2015**	**2014 [(a)]**	**2013**	**2012 [(b)]**
Statement of Operations data:					
Operating revenues	$ 17,751	$ 19,135	$ 17,393	$ 15,630	$ 14,437
Operating income	836	2,275	1,176	1,677	1,113
Net income	558	1,340	1,019	1,060	558

(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) The 2012 financial results include the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.

80

(In millions)	December 31, 2016	2015	2014	2013	2012
Balance Sheet data:					
Current assets	$ 6,528	$ 6,342	$ 7,311	$ 5,964	$ 6,211
Property, plant and equipment, net	25,585	25,843	23,028	20,111	19,531
Total assets	46,974	46,529	44,951	40,700	40,648
Current liabilities	5,683	4,933	4,459	3,842	3,969
Long-term debt, including long-term debt to affiliate	8,124	8,869	7,582	7,111	7,422
Member s equity	11,482	11,635	12,718	12,725	12,557

ComEd

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

(In millions)	For the Years Ended December 31, 2016	2015	2014	2013	2012
Statement of Operations data:					
Operating revenues	$ 5,254	$ 4,905	$ 4,564	$ 4,464	$ 5,443
Operating income	1,205	1,017	980	954	886
Net income	378	426	408	249	379

(In millions)	December 31, 2016	2015	2014	2013	2012
Balance Sheet data:					
Current assets	$ 1,554	$ 1,518	$ 1,723	$ 1,540	$ 1,692
Property, plant and equipment, net	19,335	17,502	15,793	14,666	13,826
Total assets	28,335	26,532	25,358	24,089	22,793
Current liabilities	2,938	2,766	1,923	2,032	1,655
Long-term debt, including long-term debt to financing trusts	6,813	6,049	5,870	5,235	5,492
Shareholders equity	8,725	8,243	7,907	7,528	7,323

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.

(In millions)	For the Years Ended December 31, 2016	2015	2014	2013	2012
Statement of Operations data:					

Operating revenues	$ 2,994	$ 3,032	$ 3,094	$ 3,100	$ 3,186
Operating income	702	630	572	666	623
Net income	438	378	352	395	381

Table of Contents

(In millions)	December 31, 2016	2015	2014	2013	2012
Balance Sheet data:					
Current assets	$ 757	$ 842	$ 645	$ 821	$ 1,054
Property, plant and equipment, net	7,565	7,141	6,801	6,384	6,078
Total assets	10,831	10,367	9,860	9,521	9,303
Current liabilities	727	944	653	889	1,158
Long-term debt, including long-term debt to financing trusts	2,764	2,464	2,416	2,120	1,821
Preferred securities					87
Shareholders equity	3,415	3,236	3,121	3,065	2,982

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)	For the Years Ended December 31, 2016	2015	2014	2013	2012
Statement of Operations data:					
Operating revenues	$ 3,233	$ 3,135	$ 3,165	$ 3,065	$ 2,735
Operating income	550	558	439	449	132
Net income	294	288	211	210	4

(In millions)	December 31, 2016	2015	2014	2013	2012
Balance Sheet data:					
Current assets	$ 842	$ 845	$ 951	$ 1,009	$ 979
Property, plant and equipment, net	7,040	6,597	6,204	5,864	5,498
Total assets	8,704	8,295	8,056	7,839	7,485
Current liabilities	707	1,134	794	800	980
Long-term debt, including long-term debt to financing trusts and variable interest entities	2,533	1,732	2,109	2,179	1,949
Shareholders equity	2,848	2,687	2,563	2,365	2,168

PHI

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

Successor *Predecessor*

(In millions)	March 24 - December 31 2016	January 1 - March 23 2016	For the Years Ended December 31, 2015	2014
Statement of Operations data [a]:				
Operating revenues	$ 3,643	$ 1,153	$ 4,935	$ 4,808
Operating income	93	105	673	605
Net (loss) income from continuing operations	(61)	19	318	242
Net (loss) income	(61)	19	327	242

Table of Contents

(In millions)	Successor December 31, 2016	Predecessor December 31, 2015
Balance Sheet data [a]:		
Current assets	$ 1,838	$ 1,474
Property, plant and equipment, net	11,598	10,864
Total assets	21,025	16,188
Current liabilities	2,284	2,327
Long-term debt	5,645	4,823
Preferred Stock		183
Member s equity/Shareholders equity	8,016	4,413

(a) As a result of the PHI Merger in 2016, Exelon has elected to present PHI s selected financial data for the periods reflected above.

Pepco

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

(In millions)	For the Years Ended December 31, 2016	2015	2014
Statement of Operations data [a]:			
Operating revenues	$ 2,186	$ 2,129	$ 2,055
Operating income	174	385	349
Net (loss) income	42	187	171

(In millions)	December 31, 2016	2015
Balance Sheet data [a]:		
Current assets	$ 684	$ 726
Property, plant and equipment, net	5,571	5,162
Total assets	7,335	6,908
Current liabilities	596	455
Long-term debt	2,333	2,340
Shareholders equity	2,300	2,240

(a) As a result of the PHI Merger in 2016, Exelon has elected to present Pepco s selected financial data for the periods reflected above.

DPL

The selected financial data presented below has been derived from the audited consolidated financial statements of DPL. This data is qualified in its entirety by reference to and should be read in conjunction with DPL 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)	**2016**	**2015**	**2014**
Statement of Operations data [(a)]:			
Operating revenues	$ 1,277	$ 1,302	$ 1,282
Operating income	50	165	207
Net (loss) income	(9)	76	104

83

Table of Contents

(In millions)	December 31, 2016	2015
Balance Sheet data [a]:		
Current assets	$ 370	$ 388
Property, plant and equipment, net	3,273	3,070
Total assets	4,153	3,969
Current liabilities	381	564
Long-term debt	1,221	1,061
Shareholders equity	1,326	1,237

(a) As a result of the PHI Merger in 2016, Exelon has elected to present DPL s selected financial data for the periods reflected above.

ACE

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

(In millions)	For the Years Ended December 31, 2016	2015	2014
Statement of Operations data [a]:			
Operating revenues	$ 1,257	$ 1,295	$ 1,210
Operating income	7	134	137
Net (loss) income	(42)	40	46

(In millions)	December 31, 2016	2015
Balance Sheet data [a]:		
Current assets	$ 399	$ 546
Property, plant and equipment, net	2,521	2,322
Total assets	3,457	3,387
Current liabilities	320	297
Long-term debt	1,120	1,153
Shareholders equity	1,034	1,000

(a) As a result of the PHI Merger in 2016, Exelon has elected to present ACE s selected financial data for the periods reflected above.

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.

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.

Pepco, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission in the District of Columbia and major portions of Prince George s County and Montgomery County in Maryland.

DPL, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in northern Delaware.

ACE, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in southern New Jersey.

Pepco, DPL and ACE are operating companies of PHI, which is a utility services holding company and a wholly owned subsidiary of Exelon.

Exelon has twelve reportable segments consisting of Generation s six reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions in Generation), ComEd, PECO, BGE and PHI s three utility reportable segments (Pepco, DPL and ACE). See Note 26 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.

PHI Service Company, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHI Service Company and the participating operating subsidiaries.

Table of Contents

Exelon s consolidated financial information includes the results of its eight separate operating subsidiary registrants, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, 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, BGE, PHI, Pepco, DPL and ACE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Financial Results of Operations

GAAP Results of Operations

The following tables set forth Exelon s GAAP consolidated results of operations for the year ended December 31, 2016 compared to the same period in 2015. 2016 amounts include the operations of PHI, Pepco, DPL and ACE from March 24, 2016 through December 31, 2016. All amounts presented below are before the impact of income taxes, except as noted.

	For the Years Ended December 31, 2016								Favorable
								2015	(Unfavorable)
	Generation	ComEd	PECO	BGE	PHI[b]	Other	Exelon	Exelon	Variance
Operating revenues	$ 17,751	$ 5,254	$ 2,994	$ 3,233	$ 3,643	$ (1,515)	$ 31,360	$ 29,447	$ 1,913
Purchased power and fuel expense	8,830	1,458	1,047	1,294	1,447	(1,436)	12,640	13,084	444
Revenue net of purchased power and fuel expense [a]	8,921	3,796	1,947	1,939	2,196	(79)	18,720	16,363	2,357
Other operating expenses									
Operating and maintenance	5,641	1,530	811	737	1,233	96	10,048	8,322	(1,726)
Depreciation and amortization	1,879	775	270	423	515	74	3,936	2,450	(1,486)
Taxes other than income	506	293	164	229	354	30	1,576	1,200	(376)
Total other operating expenses	8,026	2,598	1,245	1,389	2,102	200	15,560	11,972	(3,588)
Gain (Loss) on sales of assets	(59)	7			(1)	5	(48)	18	(66)
Operating income (loss)	836	1,205	702	550	93	(274)	3,112	4,409	(1,297)
Other income and (deductions)									

Interest expense, net	(364)	(461)	(123)	(103)	(195)	(290)	(1,536)	(1,033)	(503)
Other, net	401	(65)	8	21	44	4	413	(46)	459
Total other income and (deductions)	37	(526)	(115)	(82)	(151)	(286)	(1,123)	(1,079)	(44)
Income (loss) before income taxes	873	679	587	468	(58)	(560)	1,989	3,330	(1,341)
Income taxes	290	301	149	174	3	(156)	761	1,073	312
Equity in (losses) earnings of unconsolidated affiliates	(25)					1	(24)	(7)	(17)
Net income (loss)	558	378	438	294	(61)	(403)	1,204	2,250	(1,046)
Net income (loss) attributable to noncontrolling interests and preference stock dividends	62			8			70	(19)	89
Net income (loss) attributable to common shareholders	$ 496	$ 378	$ 438	$ 286	$ (61)	$ (403)	$ 1,134	$ 2,269	$ (1,135)

(a) The Registrants evaluate operating performance using the measure of revenues net of purchased power and fuel expense. The Registrants believe that revenues net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenues net of purchased power and fuel

86

Table of Contents

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) As a result of the PHI Merger, PHI includes the consolidated results of PHI, Pepco, DPL and ACE from March 24, 2016 through December 31, 2016.

Exelon s net income attributable to common shareholders was $1,134 million for the year ended December 31, 2016 as compared to $2,269 million for the year ended December 31, 2015, and diluted earnings per average common share were $1.22 for the year ended December 31, 2016 as compared to $2.54 for the year ended December 31, 2015.

Operating revenues net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $2,357 million as compared to 2015. The year-over-year increase was primarily due to the following favorable factors:

- Increase of $2,196 million in revenue net of purchased power and fuel due to the inclusion of PHI s results for the period of March 24, 2016 to December 31, 2016;
- Increase of $210 million at ComEd primarily due to increased distribution and transmission formula rate revenue resulting from increased capital investment, as well as, favorable weather;
- Increase of $109 million at BGE primarily due to increased transmission revenue as a result of increased capital investments and operating and maintenance expense recoveries and increased distribution revenue pursuant to increased rates as a result of the distribution rate orders issued by the MDPSC in June 2016 and July 2016;
- Increase of $105 million at Generation primarily due to the impact of the Ginna Reliability Support Services Agreement and a decrease in nuclear outage days at higher capacity units despite an increase in overall outage days, partially offset by lower realized energy prices; and
- Increase of $105 million at PECO primarily due to increased electric distribution revenue pursuant to a rate increase effective January 1, 2016.

The year-over-year increase in operating revenues net of purchased power and fuel expense described above was partially offset by a decrease of $298 million at Generation due to mark-to-market losses of $41 million in 2016 from economic hedging activities as compared to gains of $257 million in 2015.

Operating and maintenance expense increased by $1,726 million as compared to 2015. The year-over-year increase was primarily due to the following unfavorable factors:

- Increase of $910 million, exclusive of merger commitment costs discussed above, due to the inclusion of PHI s results for the period March 24, 2016 to December 31, 2016;

Approval of the merger across all regulatory jurisdictions was conditioned on Exelon and PHI agreeing to certain commitments pursuant to which, upon acquisition close, Exelon recorded $513 million of costs;

Increase in Generation s labor, contracting and materials cost of $185 million related to the inclusion of Pepco Energy Services results in 2016 and increased contracting costs related to energy efficiency projects;

Long-lived asset impairments of $171 million at Generation in 2016 compared to $10 million in 2015;

Increase of $54 million at BGE primarily as a result of one-time charges associated with the reduction of regulatory assets and other long-lived assets stemming from certain cost disallowances contained within the distribution rate orders issued by the MDPSC in June and July 2016; and

- Increase of $28 million at Generation for the recognition of one-time charges associated with Generation s 2016 decision to early retire the Clinton and Quad Cities nuclear generating facilities.

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

- Decrease of $79 million at Generation as a result of the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units in 2016 versus 2015;
- Decrease of $79 million at Generation as a result of a decrease in nuclear outage days in 2016, excluding Salem; and
- Decrease of $77 million in pension and non-pension post-retirement benefit costs resulting from the favorable impact of higher pension and OPEB discount rates in 2016.

Depreciation and amortization expense increased by $1,486 million primarily as a result of accelerated depreciation and amortization expense related to Generation s previous decision to early retire the Clinton and Quad Cities nuclear generating facilities, increased nuclear decommissioning amortization at Generation, increased depreciation expense due to ongoing capital expenditures across all operating companies and the inclusion of PHI s results for the period of March 24, 2016 to December 31, 2016.

Taxes other than income increased $376 million primarily due to increased property and utility taxes as a result of the inclusion of PHI s results for the period March 24, 2016 to December 31, 2016.

Gain (Loss) on sales of assets decreased $66 million primarily due to certain Generation projects and contracts being terminated or renegotiated in 2016, partially offset by a gain associated with Generation s sale of the retired New Boston generating site in 2016.

Interest expense, net increased by $503 million primarily due to the recognition of the interest due on the asserted penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position, higher outstanding debt to fund the PHI acquisition and general corporate purposes and the absence of the forward-starting interest rate swaps in 2016.

Other, net increased by $459 million primarily due to the change in realized and unrealized gains and losses on NDT funds at Generation, partially offset by the recognition of the penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position.

Exelon s effective income tax rates for the years ended December 31, 2016 and 2015 were 38.3% and 32.2%, 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. Exelon recorded an after-tax charge of $98 million for the year ended December 31, 2016 as a result of the assessment and remeasurement of certain federal and state PHI, Pepco, DPL and ACE uncertain tax positions.

For further detail regarding the financial results for the years ended December 31, 2016 and 2015, including explanation of the non-GAAP measure revenues net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

88

Table of Contents

Adjusted (non-GAAP) Operating Earnings

Exelon s adjusted (non-GAAP) operating earnings for the year ended December 31, 2016 were $2,488 million, or $2.68 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,227 million, or $2.49 per diluted share, for the same period in 2015. In addition to net income, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor s overall understanding of year-to-year operating results and provide an indication of Exelon s baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the year ended December 31, 2016 as compared to 2015:

	For the years ended December 31,			
	2016		2015	
(All amounts after tax; in millions, except per share amounts)		**Earnings per Diluted Share**		**Earnings per Diluted Share**
Net Income Attributable to Common Shareholders	$ 1,134	$ 1.22	$ 2,269	$ 2.54
Mark-to-Market Impact of Economic Hedging Activities [a]	24	0.03	(158)	(0.18)
Unrealized (Gains) Losses Related to NDT Fund Investments [b]	(118)	(0.13)	115	0.13
Plant Retirements and Divestitures [c]	432	0.47		
Asset Retirement Obligation [d]	(75)	(0.08)	(6)	(0.01)
Merger and Integration Costs [e]	114	0.12	58	0.07
Amortization of Commodity Contract Intangibles [f]	35	0.04	(5)	
Reassessment of State Deferred Income Taxes [g]	10	0.01	41	0.05
Long-Lived Asset Impairments [h]	103	0.11	21	0.02
Tax Settlements [i]			(52)	(0.06)
Mark-to-Market Impact of PHI Merger Related Interest Rate Swaps [j]			(21)	(0.02)
PHI Merger Related Redeemable Debt Exchange [k]			13	0.01
Reduction in State Income Tax Reserve [l]			(10)	(0.01)
Midwest Generation Bankruptcy Recoveries [m]			(6)	(0.01)
Merger Commitments [n]	437	0.47		
Curtailment of Generation Growth and Development Activities [o]	57	0.06		
Cost Management Program [p]	34	0.04		
Like-Kind Exchange Tax Position [q]	199	0.21		
CENG Noncontrolling Interests [r]	102	0.11	(32)	(0.04)

Adjusted (non-GAAP) Operating Earnings	$ 2,488	$ 2.68	$ 2,227	$ 2.49

(a) Reflects the impact of (gains) losses for the years ended December 31, 2016 and 2015 (net of taxes of $18 million and $99 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 (gains) losses for the years ended December 31, 2016 and 2015 (net of taxes of $112 million and $148 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) Primarily reflects incremental accelerated depreciation and amortization expenses from June 2, 2016 through December 6, 2016 and construction work in progress impairments pursuant to the second quarter decision to early retire the Clinton and Quad Cities nuclear generating facilities, which decision was reversed in December 2016 (net of taxes of $285 million), partially offset by a gain associated with Generation s 2016 sale of the New Boston generating site (net of taxes of $12 million).

(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, 2016 and 2015 (net of taxes of $13 million and $4 million, respectively).

(e) Reflects certain costs associated with mergers and acquisitions incurred for the years ended December 31, 2016 and 2015 (net of taxes of $50 million and $38 million, respectively) including professional fees, employee-related expenses, integration activities and upfront credit facilities fees related to the PHI acquisition and pending Fitzpatrick acquisition, partially offset in 2016 at ComEd, BGE and PHI by the anticipated recovery of previously incurred PHI acquisition costs.

(f) Reflects the non-cash impact for the years ended December 31, 2016 and 2015 (net of taxes of $22 million and $3 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) Reflects impairment of upstream assets and certain wind projects in 2016 (net of taxes of $68 million) and the impairment of investment in long-term leases at Corporate in 2015 (net of taxes of $13 million).

(i) Reflects a benefit related to the favorable settlement in 2015 of certain income tax positions on Constellation s pre-acquisition tax returns.

(j) Reflects the impact of mark-to-market activity on forward-starting interest rate swaps held at Exelon Corporate related to financing for the PHI acquisition for the year ended December 31, 2015 (net of taxes of $14 million).

(k) 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 in 2015).

(l) 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.

(m) 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).

(n) Represents adjustments to costs incurred as part of the settlement orders approving the PHI acquisition and a charge related to a 2012 CEG merger commitment for the year ended December 31, 2016 (net of taxes of $126 million).

(o) Reflects the one-time recognition for a loss on sale of assets and asset impairment charges pursuant to Generation s strategic decision to narrow the scope and scale of its growth and development activities for the year ended December 31, 2016 (net of taxes of $35 million).

(p) Represents 2016 severance expense and reorganization costs related to a cost management program (net of taxes of $21 million).

(q) Represents the recognition of a penalty and associated interest expense in the third quarter of 2016, as a result of a tax court decision on Exelon s like-kind exchange tax position (net of taxes of $61 million).

(r) Represents elimination from Generation s results of the noncontrolling interests related to CENG exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments and changes in asset retirement obligations in 2016, and in 2015 the impact of unrealized gains and losses on NDT fund investments and mark-to-market activity.

Merger and Acquisition Costs

On March 23, 2016, the Exelon and PHI Merger was completed. On the merger date, PHI shareholders received $27.25 of cash in exchange for each share of PHI common stock. The resulting company retained the Exelon name and is headquartered in Chicago.

As a result of the PHI Merger, Exelon has incurred costs associated with evaluating, structuring and executing the PHI Merger transaction itself, and will continue to incur cost associated with meeting the various commitments set forth by regulators and agreed-upon with other interested parties as part of the merger approval process, and integrating the former PHI businesses into Exelon.

Table of Contents

The table below presents the one-time pre-tax charges recognized for the PHI Merger included in the Registrant s respective Consolidated Statements of Operations and Comprehensive Income.

	For the Year Ended December 31, 2016					*Successor* March 24, 2016 to December 31, 2016
	Exelon	**Generation**	**Pepco**	**DPL**	**ACE**	**PHI**
Merger commitments	$ 513	$ 3	$ 126	$ 86	$ 111	$ 323
Changes in accounting and tax related policies and estimates			25	15	5	
Total	$ 513	$ 3	$ 151	$ 101	$ 116	$ 323

In addition to the one-time PHI Merger charges discussed above, for the years ended December 31, 2016 and 2015, expense has been recognized for the PHI Merger, Constellation acquisition and the pending FitzPatrick acquisition as follows:

	Pre-tax Expense For the Year Ended December 31, 2016								
Merger Integration and Acquisition Expense:	**Exelon** [(a)]	**Generation** [(a)]	**ComEd**	**PECO**	**BGE**	**PHI** [(a)]	**Pepco** [(a)]	**DPL** [(a)]	**ACE** [(a)]
Transaction [(c)]	34	2							
Employee-related [(d)]	77	10	2	1	1	64	30	18	15
Other [(e)]	52	44	(8)	4	(2)	5	(2)	2	4
Total	$ 163	$ 56	$ (6)	$ 5	$ (1)	$ 69	$ 28	$ 20	$ 19

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

(a) For Exelon, Generation, PHI, Pepco, DPL, and ACE, includes the operations of the acquired businesses beginning on March 24, 2016.

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

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

(d) Costs primarily for employee severance, pension and OPEB expense and retention bonuses.

(e) For the year ended December 31, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million, $6 million, $11 million, $4 million and $16 million incurred at ComEd, BGE, Pepco, DPL and PHI, respectively, that has been deferred and recorded as a regulatory asset for anticipated recovery. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for more information. For the year ended December 31, 2015, includes costs to integrate CENG, Constellation and Integrys systems into Exelon and terminate certain Constellation debt agreements. Also includes professional fees primarily related to integration for the PHI acquisition.

As of December 31, 2016, Exelon expects to incur total PHI acquisition and integration related costs of approximately $700 million, excluding merger commitments. Of this amount, including costs incurred from 2014 through December 31, 2016, Exelon and PHI have incurred approximately $610 million. 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 $30 million for integration costs expected to be capitalized to Property, plant and equipment.

Significant 2016 Transactions and Developments

PHI Acquisition

On March 23, 2016, Exelon completed its acquisition of PHI for a total cash purchase price of $7.1 billion, significantly expanding its regulated utility business and resulting in a total of over 10 million utility customers. In accounting for the acquisition as a business combination, Exelon and PHI recorded $4.0 billion in goodwill. Approval of the merger in Delaware, New Jersey, Maryland and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments including customer rate credits, funding for energy efficiency and delivery system modernization programs, and other various requirements, for which Exelon recorded $513 million of Operating and maintenance expense for the year ended December 31, 2016. The Registrants have also incurred costs for evaluating, structuring and executing the transaction, as well as integrating the former PHI businesses into Exelon. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information regarding the PHI acquisition and related costs.

Illinois Future Energy Jobs Act

On December 7, 2016, FEJA was signed into law by the Governor of Illinois. FEJA is effective June 1, 2017, and includes, among other provisions, (1) a ZES providing compensation for certain nuclear-powered generating facilities, (2) an extension of and certain adjustments to ComEd s electric distribution formula rate, (3) new cumulative persisting annual energy efficiency MWh savings goals for ComEd, (4) revisions to the Illinois RPS requirements, (5) provisions for adjustments to or termination of FEJA programs if the average impact on ComEd s customer rates exceeds specified limits, (6) revisions to the existing net metering statute to (i) mandate net metering for community generation projects, and establish billing procedures for subscribers to those projects, (ii) provide immediately for netting at the energy-only rate for nonresidential customers, and (iii) transition from netting at the full retail rate to the energy-only rate for certain residential net metering customers once the net meter customer load equals 5% of total peak demand supplied in the previous year and (7) support for low income rooftop and community solar programs. FEJA establishes new or adjusts existing rate recovery mechanisms for ComEd to recover costs associated with the new or expanded energy efficiency and RPS requirements. Regulatory or legal challenges over the validity of FEJA are possible. See Note 3 Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information regarding FEJA. See Note 9 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for the impacts of ZES on Generation s Consolidated Balance Sheets and Consolidated Statements of Operations and Comprehensive Income.

New York Clean Energy Standard

On August 1, 2016, the New York Public Service Commission (NYPSC) issued an order establishing the CES, a component of a Tier 3 ZEC program targeted at preserving the environmental attributes of qualifying zero-emissions nuclear-powered generating facilities, including CENG s Ginna, and Nine Mile Point and Entergy Nuclear Fitzpatrick LLC s (Entergy) 838 MW single unit James A. FitzPatrick facilities. On November 18, 2016, required contracts with the New York State Energy Research and Development Authority (NYSERDA) were executed for each of these three plants.

Regulatory and legal challenges over the validity the New York CES have been made, the outcomes of which remain uncertain. Also in August 2016, Generation executed a series of agreements with Entergy to acquire the Fitzpatrick nuclear generating station, subject to various regulatory approvals. The transaction is anticipated to close in the first or second quarter of 2017. See Note 3 Regulatory Matters Matters of the Combined Notes to the Consolidated Financial Statements for regulatory updates related to the New York CES, Note 9 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information relative to Ginna and Nine Mile Point, and Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information on Generation s proposed acquisition of FitzPatrick.

Potential Early Nuclear Plant Retirements

Exelon and Generation continually 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 and regulatory solutions to ensure nuclear plants are fairly compensated for their carbon-free emissions, and the impact of final rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules. In 2015 and 2016, Generation identified the Clinton, Quad Cities, Ginna, Nine Mile Point, and Three Mile Island nuclear plants as having the greatest risk of early retirement based on economic valuation and other factors. On June 2, 2016, Generation announced its decision to shut down the Clinton and Quad Cities nuclear plants on June 1, 2017 and June 1, 2018, respectively; thereby resulting in accelerated depreciation for these plant assets thereafter. With the passage of the Illinois ZES on December 7, 2016, Generation reversed its original decision, and revised the expected economic useful lives for both facilities to 2027 for Clinton and to 2032 for Quad Cities. Furthermore, assuming the successful implementation of the Illinois ZES and the New York CES for their entire terms, Generation no longer considers Clinton, Quad Cities, Ginna or Nine Mile Point to be at heightened risk of early retirement. Generation currently considers Three Mile Island to be at the greatest risk of early retirement due to current economic valuations and other factors. See Note 9 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information.

Like-Kind Exchange

On September 19, 2016, the United States Tax Court rejected Exelon s position on its 1999 income tax return to defer under the like-kind exchange provisions of the IRC $1.2 billion of tax gain on the sale of ComEd s fossil generating assets. In addition, contrary to Exelon s evaluation that any penalty was unwarranted, the Tax Court ruled that Exelon is liable for the penalty and interest thereon asserted by the IRS, pursuant to which Exelon and ComEd recorded charges to earnings in 2016 of $106 million and $86 million, respectively. Exelon expects to timely appeal this decision to the U.S. Court of Appeals for the Seventh Circuit. While awaiting a final calculation from the IRS, Exelon estimates an approximate $1.4 billion payment will be due, including $300 million form ComEd, in the second quarter of 2017 at the time it expects to file its appeal. Of this amount, Exelon deposited with the IRS $1.25 billion in October 2016, with the remainder to be paid at the time the appeal is filed. See Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for further information related to the like-kind exchange tax matter, including Exelon s agreement to hold ComEd harmless from any unfavorable impacts of after-tax interest or penalty amounts on ComEd s equity.

BGE 2015 Electric and Natural Gas Distribution Base Rates

On November 6, 2015, and as amended through the course of the proceeding, BGE filed for electric and natural gas base rate increases with the MDPSC, which included recovery of electric and

natural gas smart grid initiative costs. On June 3, 2016, the MDPSC issued an order in which the MDPSC found compelling evidence to conclude that BGE s smart grid initiative overall was cost beneficial to customers. However, the June 3 order contained several cost disallowances and adjustments, which BGE filed a petition for rehearing on and certain of which were reversed by the MDPSC in an order issued on July 29, 2016. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

Pepco Maryland 2016 Electric Distribution Base Rates

On November 15, 2016, the MDPSC approved an increase in electric distribution base rates of $53 million based on a ROE of 9.55%. The new rates became effective for services rendered on or after November 15, 2016. MDPSC also approved Pepco s recovery of substantially all of its capital investment and regulatory assets associated with its AMI program as part of the newly effective rates as well as recovery over a five-year period of transition costs related to a new billing system implemented in 2015. As a result, during the fourth quarter of 2016, Exelon, PHI and Pepco established a regulatory asset of $13 million, wrote off $3 million in disallowed AMI costs and recorded a pre-tax credit to net income for $10 million. Additionally, the MDPSC denied Pepco s request to extend its Grid Resiliency Program surcharge for new system reliability and safety improvement projects, with costs for such programs to be recovered going forward through base rates. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

DPL Delaware 2016 Electric and Natural Gas Distribution Base Rates

The DPSC approved provisional increases in annual electric and natural gas distribution base rates of $2.5 million effective May 17, 2016, and an additional $30 million effective December 17, 2016, for electric and of $2.5 million effective May 17, 2016, and an additional $10 million effective December 17, 2016, for gas. These increases are subject to refund based on the final DPSC orders. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

DPL filed an application with the DPSC to increase its annual electric and natural gas distribution base rates by $63 million and $22 million, respectively, based on a requested ROE of 10.6%. While the DPSC is not required to issue a decision on the application within a specified period of time, Delaware law allowed DPL to put into effect $2.5 million of each of the rate increases two months after filing the applications which were effective July 16, 2016. On December 1, 2016, the DPSC approved that an additional $30 million in electric distribution base rates be implemented effective December 17, 2016, subject to refund based on the final DPSC order, and an additional $10 million in gas base rates be implemented effective December 17, 2016, subject to refund based on the final DPSC order. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

ACE 2016 Electric Distribution Base Rates

On August 24, 2016, the NJBPU issued an order approving a stipulation of settlement among ACE, the New Jersey Division of Rate Counsel, NJBPU Staff and Unimin Corporation, and an increase of $45 million (before New Jersey sales and use tax) to its electric distribution base rates, with the new rates effective immediately. The stipulation of settlement provided that a determination on PowerAhead would be separated into a phase II of the rate proceeding and decided at a later date, most likely in the first quarter of 2017. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

Exelon s Strategy and Outlook for 2017 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 and to reduce debt.

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 benefit to customers and the community by improving reliability and the service experience or otherwise meeting customer needs. The Exelon utilities make these investments 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 resources and best practices to achieve improved operational and financial results. Additionally, 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 stable revenues and 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 the Registrants, 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 has approved a dividend policy providing a raise of 2.5% each year for three years, beginning with the June 2016 dividend.

Various market, financial, regulatory, legislative and operational 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.

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 approximately $350 million and $50 million, respectively, of which approximately 35% of run-rate savings was achieved by the end of 2016. Approximately 60% of run-rate savings are expected to be achieved by the end of 2017 and fully realized in 2018. At least 75% of the savings are expected to be allocated to Generation, with the remaining amount allocated to the Utility Registrants.

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 PHI merger provides an opportunity to accelerate Exelon s regulated growth to provide stable cash flows, earnings accretion, and dividend support. Additionally, the Utility Registrants anticipate investing approximately $25 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 $9 billion by the end of 2021. The Utility Registrants 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 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, 2016, Generation has currently approved plans to invest a total of approximately $1 billion in 2017 through 2019 on capital growth projects (primarily new plant construction and distributed generation).

Liquidity Considerations

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, BGE, Pepco, DPL and ACE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.6 billion, $5.3 billion, $1.0 billion, $0.6 billion, $0.6 billion, $0.5 billion, $0.5 billion and $0.4 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.5 billion. See Liquidity and Capital Resources Credit Matters Exelon Credit Facilities below.

Table of Contents

Project Financing

Generation utilizes individual project financings as a means to finance the construction of various generating asset projects. Project financing is based upon a nonrecourse financial structure, in which project debt and equity used to finance the project are paid back from the cash generated by the newly constructed asset once operational. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default. If a specific project financing entity does not maintain compliance with its specific nonrecourse debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to satisfy its associated debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful life. See Note 14 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on nonrecourse debt.

ExGen Texas Power

In September 2014, ExGen Texas Power, LLC (EGTP), an indirect subsidiary of Exelon and Generation, issued $675 million aggregate principal amount of a nonrecourse senior secured term loan. The net proceeds were distributed to Generation for general business purposes. EGTP s operating cash flows have been negatively impacted by certain market conditions including, but not limited to: low power prices, higher fuel prices and the seasonality of its cash flows . Despite the declining operating cash flows, EGTP remains in compliance with its covenants related to the project specific financing. Management continues to monitor the project entity s short term liquidity needs. See Note 14 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the EGTP.

Other Key Business Drivers and Management Strategies

Utility Rates and Rate Proceedings

The Utility Registrants file rate cases with their regulatory commissions seeking increases or decreases to their electric transmission and distribution, and gas distribution rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Utility Registrants current and future results of operations, cash flows and financial position. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further details on these regulatory proceedings.

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). On May 10, 2016, FERC largely denied rehearing, and a number of parties appealed to the U.S. Court of Appeals for the DC Circuit for review of the decision. It is too early in the process to predict the appeal outcome.

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 be changed prior to the April 2016 auction which set capacity prices for the 2016/2017 planning year. In response to this order, MISO filed certain rule changes with the FERC. On March 18, 2016, FERC largely denied rehearing of its December 31, 2015 order. 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 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on the impacts of the MISO announcement.

98

MISO has acknowledged the need for capacity market design changes in the zone 4 regions, and on November 1, 2016 filed a comprehensive capacity market proposal for the zone 4 region (as well as another zone). It is too early to predict the outcome of that filing. Exelon is generally supportive of such changes. However, several fossil generators have requested that FERC impose an expanded minimum offer price rule (MOPR) that could affect capacity offers from the Clinton nuclear plant. See Note 9 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on the impacts of the MISO announcement. Exelon is actively participating in this aspect of the proceeding, seeking to avoid the implementation of such a MOPR mechanism. However, it is too early in the proceeding to predict.

Subsidized Generation

The rate of expansion of subsidized generation, in the markets in which Generation s output is sold can negatively impact wholesale power prices, and in turn, Generation s results of operations.

Various states have 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 was required to construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland. The CfD mandated that utilities (including BGE, Pepco and DPL) 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. On April 19, 2016, the U.S. Supreme Court affirmed the decision of the U.S. Court of Appeals for the Fourth Circuit, and subsequently denied certiorari with respect to the appeal from the U.S. Court of Appeals for the Third Circuit, leaving in place that court s decision. The matter is now considered closed.

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. While the court decisions 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 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) 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 for what was collectively more than 6,000MW of primarily coal-fired generation. Thus, the Riders were similar to the CfDs described above (except that the PPA Riders in Ohio would apply to existing generation facilities whereas the CfDs applied to new generation facilities). While FERC orders on April 27, 2016 largely alleviated the concerns related to the Riders by holding that the PPAs ran afoul of affiliate restrictions on FE and AEP, we continue to closely monitor developments in Ohio.

In addition, Exelon continues to monitor developments in Maryland, New Jersey, and other states 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.

Complaints at FERC Seeking to Mitigate Illinois and New York Programs Providing ZECs

PJM and NYISO capacity markets include a Minimum Offer Price Rule (MOPR) that is intended to preclude buyers from exercising buyer market power. If a resource is subjected to a MOPR, its offer is adjusted to remove the revenues it receives through a federal, state or other government-provided financial support program resulting in a higher offer that may not clear the capacity market. Currently, the MOPRs in PJM and NYISO apply only to certain new resources. Exelon has generally opposed policies that required subsidies 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. Thus, Exelon has supported a MOPR as a means of minimizing the detrimental impact of certain subsidized resources could have on capacity markets (such as the New Jersey (LCAPP) and Maryland (CfD) programs. However, in Exelon s view, MOPRs should not be applied to resources that receive compensation for providing superior reliability or environmental benefits.

On January 9, 2017, the Electric Power Supply Association (EPSA) filed two requests with FERC: one seeking to amend a prior complaint against PJM and another seeking expedited action on a pending NYISO compliance filing in an existing proceeding. Both filings allege that the relevant MOPR should be expanded to also apply to existing resources receiving ZEC compensation under the New York CES and Illinois ZES programs. Exelon has filed protests at FERC in response to each filing, arguing generally that ZEC payments provide compensation for an environmental attribute that is distinct from the energy and capacity sold in the FERC-jurisdictional markets, and therefore, are no different than other renewable support programs like the PTC and RPS that have generally not been subject to a MOPR. However, if successful, an expanded MOPR could result in mitigation of Generation s Quad Cities, Ginna, and Nine Mile Point facilities, which are expected to receive ZEC compensation, such that they would have an increased risk of not clearing in future capacity auctions and thus no longer receiving capacity revenues during the respective ZEC programs. This would also impact the FitzPatrick facility that Generation is currently in the process of acquiring from Entergy. Any mitigation of these generating resources could have a material effect on Exelon s and Generation s future cash flows and results of operations. The timing of FERC s decision with respect to both proceedings is currently unknown and the outcome of these matters is currently uncertain.

Energy Demand

Modest economic growth partially offset by energy efficiency initiatives is resulting in positive growth for electricity for Pepco, a decrease in projected load for electricity for BGE, DPL and ACE, and an essentially flat projected load for electricity for ComEd and PECO. ComEd, PECO, BGE, Pepco, DPL and ACE are projecting load volumes to increase (decrease) by (0.3)%, 0.6%, (1.4)%, (1.7)%, 0.8% and (0.7)%, respectively, in 2017 compared 2016.

100

Table of Contents

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

As part of its strategic business planning process, 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 quarter 2016 dividends of $0.31 per share each on Exelon s common stock. The second, third and fourth quarter 2016 dividends declared was $0.318 on Exelon s common stock, and the first quarter 2017 dividends declared was $0.328 per share. The dividends for the first, second, third and fourth quarter 2016 were paid on March 10, 2016, June 10, 2016, September 9, 2016 and December 9, 2016, respectively. The first quarter 2017 dividend is payable on March 10, 2017.

Exelon s Board of Directors has approved a dividend policy providing a raise of 2.5% each year for three years, beginning with the June 2016 dividend.

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 2017 and 2018. 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, 2016, the percentage of expected generation hedged for the major reportable segments was 91%-94%, 56%-59% and 28%-31% for 2017, 2018, and 2019 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 generating facilities 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 39% of Generation s uranium concentrate requirements from 2017 through 2021 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrate 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.

The Utility Registrants mitigate commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Tax Matters

Potential Corporate Tax Reform

The results of the November 2016 U.S. elections have introduced greater uncertainty with respect to federal tax policies. President Trump has stated that one of his top priorities is comprehensive tax reform and House Republicans plan to advance their tax reform blueprint . Tax reform proposals call for a reduction in the corporate federal income tax rate from the current 35% to as low as 15%. Other proposals provide, among other items, for the immediate deduction of capital investment expenditures and full or partial elimination of debt interest expense deductions. It is uncertain whether, to what extent or when these or any other changes in federal tax policies will be enacted or the transition time frame for such changes. Further, for the Utility Registrants, regulators may impose rate reductions to provide the benefit of any income tax expense reductions to customers and refund excess deferred income taxes previously collected through rates. The amounts and timing of any such rate changes would be subject to the discretion of the rate regulator in each specific jurisdiction. For these reasons, the Registrants cannot predict the impact any potential changes may have on their future results of operations, cash flows or financial position, and such changes could be material.

See Note 15 Income Taxes of the Combined Notes to the 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 implementing the Cross State Air Pollution Rule that requires 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, and otherwise contributes to non-attainment status of downwind states with the various NAAQS requirements.

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.

See Note 24 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 Legislative and Regulatory Developments

NRC Task Force on Fukishima

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 2017 through 2019 is expected to be between approximately $75 million and $100 million of capital and $15 million of operating expense. Generation s current assessments are specific to the Tier 1 recommendations. The NRC has not finalized actions with respect to the Tier 2 and Tier 3 recommendations and is expected to do so in 2017. 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.

Employees

During 2016, Exelon BSC and ComEd extended the collective bargaining agreement (CBA) with IBEW Local 15 by three years; with an expiration date of September 30, 2022. Exelon Generation extended its CBA with both the IBEW Local 15 (covering the five (5) Midwest nuclear plants) and IBEW Local 51 (Clinton) by three years; with expiration dates of April 30, 2022 and December 15, 2023, respectively. Additionally, Exelon Nuclear Security successfully ratified its CBA with the UGSOA Local 17 at Oyster Creek to an extension of five (5) years, and Exelon Power successfully ratified its CBA with the IBEW Local 614 to a three (3) extension. In January 2017, an election was held at BGE which resulted in union representation for approximately 1,400 employees. BGE and IBEW Local 410 will begin negotiations for an initial agreement which could result in some modifications to wages, hours and other terms and conditions of employment. No agreement has been finalized to date and management cannot predict the outcome of such negotiations.

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

104

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 incorporate estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional discussion of the application of these accounting policies can be found in the Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

Generation s ARO associated with decommissioning its nuclear units was $8.7 billion at December 31, 2016. 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. The availability of decommissioning trust funds could impact the timing of the decommissioning activities. Additionally, certain factors such as changes in regulatory requirements during plant operations or the profitability of a nuclear plant could impact the timing of plant retirements. These factors could result in material changes to Generation s current estimates as more information becomes available and could change the timing of plant retirements and the 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 expected costs (in current year dollars) and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within the 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 four different decommissioning approaches. In response to expected increased security costs for spent fuel stored in the spent fuel pool (wet storage), in 2016 Generation has evaluated an alternative approach for managing spent fuel between the date of a plant s cessation of operations and the fuel s acceptance for disposal by the DOE. This new approach, the Shortened SAFSTOR approach, provides for increased usage of dry cask storage for the spent fuel, and is now considered as one of the decommissioning approaches in determining the ARO 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. Spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal.

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. Spent fuel is retained in existing location (either wet or dry storage) until DOE acceptance for disposal.

3. Shortened SAFSTOR similar to the DECON scenario but with generally a 30 year delay prior to onset of decommissioning activities. Spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal.

4. 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. Spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal.

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 include the following four alternatives: (1) the probability of operating through the original 40-year nuclear license term, (2) the probability of operating through an extended 60-year nuclear license term (regardless of whether such 20-year license extension has been received for each unit), (3) the probability of a second, 20-year license renewal for some nuclear units, and (4) the probability of early plant retirement for certain sites due to changing market conditions and regulatory environments. 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 2030. The SNF acceptance date assumption is 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 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

Table of Contents

License Renewals

Except for its Clinton unit, Generation has successfully obtained initial 20-year operating license renewal extensions (i.e. extending the total license term to 60 years) for all of its operating nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG). Generation intends to apply for an initial 20-year renewal for the Clinton unit. No prior Generation license extension application has been denied.

Discount Rates

The probability-weighted estimated future cash flows for the various assumed 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 cost layer and, therefore, is 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 \$8.7 billion to approximately \$9.7 billion.

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 2015 CARFRs rather than the 2016 CARFRs in performing its annual 2016 ARO update, Generation would have decreased the ARO by an additional \$45 million; and ii) if the CARFR used in performing the annual 2016 ARO update was increased by 100 basis points or decreased by 50 basis points, the ARO would have decreased by \$1.2 billion and increased by \$150 million, respectively, as compared to the actual decrease of \$385 million.

ARO Sensitivities

Changes in the assumptions underlying the ARO 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 may correspondingly change.

Table of Contents

The following table illustrates the effects of changing certain ARO assumptions while holding all other assumptions constant (dollars in millions):

Change in ARO Assumption	Increase (Decrease) to ARO at December 31, 2016	
Cost escalation studies		
Uniform increase in escalation rates of 50 basis points	$	1,730
Probabilistic cash flow models		
Increase the estimated costs to decommission the nuclear plants by 20 percent		1,610
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points		470
Shorten each unit s probability weighted operating life assumption by 2 years		840
Extend the estimated date for DOE acceptance of SNF to 2035		140

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

Goodwill (Exelon, Generation, ComEd, PHI and DPL)

As of December 31, 2016, Exelon s $6.7 billion carrying amount of goodwill primarily consists of $2.6 billion at ComEd relating to the acquisition of ComEd in 2000 as part of the formation of Exelon and $4 billion at PHI pursuant to Exelon s acquisition of PHI in the first quarter of 2016. DPL has $8 million of goodwill as of December 31, 2016, related to its 1995 acquisition of the Conowingo Power Company. Generation also has goodwill of $47 million as of December 31, 2016. Under the provisions of the authoritative guidance for goodwill, these entities are required to perform an assessment for possible impairment of their 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 reporting units below their 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, and PHI s operating segments are Pepco, DPL and ACE. See Note 26 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information. There is no level below these operating segments for which operating results are regularly reviewed by segment management. Therefore, the ComEd, Pepco, DPL and ACE operating segments are also considered reporting units for goodwill impairment testing purposes. Exelon s and ComEd s $2.6 billion of goodwill has been assigned entirely to the ComEd reporting unit, while Exelon s and PHI s $4 billion of goodwill has been assigned to the Pepco, DPL and ACE reporting units in the amounts of $1.7 billion, $1.1 billion and $1.2 billion, respectively. DPL s $8 million of goodwill is assigned entirely to the DPL 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 conditions and events. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If an entity bypasses the qualitative assessment, or performs the qualitative assessment but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value-based test is performed.

108

Table of Contents

Exelon s, ComEd s and PHI s accounting policy is to perform a quantitative test of goodwill at least once every three years, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount. The first step in the quantitative test 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, Pepco s, DPL s and ACE s businesses 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.

Exelon, ComEd, PHI and DPL performed quantitative tests as of November 1, 2016, for their 2016 annual goodwill impairment assessments. The first step of the tests comparing the estimated fair values of the ComEd, Pepco, DPL and ACE reporting units to their carrying values, including goodwill, indicated no impairments of goodwill; therefore, no second steps were required.

While the annual assessments indicated no impairments, certain assumptions used to estimate reporting unit fair values are highly sensitive to changes. Adverse regulatory actions or changes in significant assumptions could potentially result in future impairments of Exelon s, ComEd s, PHI s or DPL s goodwill, which could be material. Based on the results of the annual goodwill tests performed as of November 1, 2016, the estimated fair values of the ComEd, Pepco, DPL and ACE reporting units would have needed to decrease by more than 30%, 10%, 10% and 10%, respectively, for Exelon, ComEd and PHI to have failed the first step of their respective impairment tests. For the $8 million of goodwill recorded at DPL related to DPL s 1995 acquisition of the Conowingo Power Company, the fair value of the DPL reporting unit would have needed to decrease by more than 50% for DPL to fail the first step of the impairment test.

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, Generation and PHI)

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 net fair value and as a bargain purchase gain on the income statement if it is below the estimated net 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. Accounting guidance provides that the allocation of the purchase price may be modified up to one year from the date of the merger as more information is obtained about the fair

value of assets acquired and liabilities assumed. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Unamortized Energy Contract Assets and Liabilities (Exelon, Generation, PHI, Pepco, DPL and ACE)

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired and the electricity and gas energy supply contracts Exelon has acquired as part of the PHI acquisition. The initial amount recorded represents the fair value of the contracts at the time of acquisition. At PHI, offsetting regulatory assets or liabilities were also recorded. The unamortized energy contract assets and liabilities and any corresponding regulatory assets or liabilities, respectively, are 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, respectively. Refer to Note 3 Regulatory Matters, 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 (All Registrants)

All Registrants 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 declines in energy prices, condition of the asset, specific regulatory disallowance, advances in technology, 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 the carrying value of 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. 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.

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.

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 (All Registrants)

The Registrants have significant investments in electric generation assets and electric and natural gas transmission and distribution assets. These assets are generally depreciated on a straight-line basis, using the composite method in which depreciation is calculated using the average estimated useful life of assets within an asset group. The estimation of asset useful lives requires management judgment, supported by formal depreciation studies of historical asset retirement experience. Depreciation studies are completed every five years, or more frequently if required by a rate regulator or if an event, regulatory action, or change in retirement patterns indicate an update is necessary.

For the Utility Registrants, depreciation studies generally serve as the basis for amounts allowed in customer rates for recovery of depreciation costs. Generally, the Utility Registrants adjust their depreciation rates for financial reporting purposes concurrent with adjustments to depreciation rates reflected in rates, unless the depreciation rates reflected in rates do not align with management s judgment as to an appropriate estimated useful life or have not been updated on a timely basis. Consistent with each utility s regulatory recovery method, the Utility Registrant s depreciation expense for each asset group includes an amount for the estimated cost of dismantling and removing plant from service spread straight line over the asset group s average remaining useful life. Estimates for such removal costs are also evaluated in the periodic depreciation studies.

At Generation, along with depreciation study results, management considers expected future energy market conditions and generation plant operating costs and capital investment requirements in determining the estimated service lives of its generating facilities. See Note 9 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on expected and potential early nuclear plant retirements.

Generation completed a depreciation rate study during the first quarter of 2015, which resulted in revised depreciation rates effective January 1, 2015.

ComEd is required to file an electric distribution depreciation rate study at least every five years with the ICC. ComEd completed an electric distribution and transmission depreciation study and filed the updated depreciation rates with both the ICC and FERC in January 2014, resulting in new depreciation rates effective first quarter 2014.

PECO is required to file electric distribution and gas depreciation rate studies at least every five years with the PAPUC. In March 2015, PECO filed a depreciation rate study with the PAPUC for both its electric distribution and gas assets, resulting in new depreciation rates for electric transmission assets effective January 1, 2015, for gas distribution assets effective July 1, 2015, and for electric distribution assets January 1, 2016.

The MDPSC does not mandate the frequency or timing of BGE s electric distribution or gas depreciation studies. In July 2014, BGE filed revised depreciation rates with the MDPSC for both its electric distribution and gas assets, which became effective December 15, 2014.

Table of Contents

The MDPSC does not mandate the frequency or timing of Pepco s electric distribution depreciation studies, while the DCPSC directs Pepco as to when it should file an electric distribution depreciation study. In 2016 and 2013, Pepco filed revised electric distribution depreciation rates with the MDPSC and DCPSC, respectively, with the new rates effective November 15, 2016 and April 16, 2014, respectively.

Neither the DPSC nor the MDPSC mandates the frequency or timing of DPL s electric distribution or gas depreciation studies. DPL filed revised depreciation rates for gas assets in 2006, with the new rates effective April 1, 2007. In 2013, DPL filed revised electric distribution depreciation rates with the MDPSC, with the new rates effective July 20, 2013. On July 20, 2016, DPL filed revised electric depreciation rates with the MDPSC as part of the electric distribution base rate filing. Any adjustments to the depreciation rates approved by the MDPSC are expected to take effect in the first quarter of 2017. On May 17, 2016, DPL filed revised electric and natural gas depreciation rates with the DPSC as part of the electric and natural gas base rate case filing. The DPSC is not required to issue a decision on the application within a specific period of time and adjustments to the depreciation rates will be made based on the outcome of the final orders, when received.

The NJBPU does not mandate the frequency or timing of ACE s electric distribution depreciation studies. In 2012, ACE filed revised electric distribution depreciation rates with the NJBPU, with the new rates effective July 1, 2013.

FERC does not mandate the frequency or timing of electric transmission depreciation studies.

Changes in estimated useful lives of electric generation assets and of electric and natural gas transmission and distribution assets could have a significant impact on the Registrants future results of operations. 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.

Defined Benefit Pension and Other Postretirement Employee Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and other postretirement employee benefit plans for substantially all 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 involves various factors, including the development of valuation assumptions and inputs 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. Exelon amortizes actuarial gains or losses in excess of a corridor of 10% of the greater of the projected benefit obligation or the market-related value (MRV) of plan assets 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 for Exelon plans was 7.00% for each of 2016, 2015 and 2014. For the predecessor periods of 2016, 2015 and 2014, the long-term EROA assumption used in calculating pension costs for the PHI plans was 6.50%, 6.50% and 7.00%, respectively. The weighted after-tax average EROA assumption used in calculating other postretirement benefit costs for Exelon plans was 6.71%, 6.50% and 6.59% in 2016, 2015 and 2014, respectively. For the predecessor periods of 2016, 2015 and 2014, the EROA assumption used in calculating other postretirement benefit costs for PHI plans was 6.75%, 6.75% and 7.25%, respectively. The pension trust activity is non-taxable, while other postretirement benefit trust activity is partially taxable. 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 6.60% to estimate its 2017 pension and other postretirement benefit costs, respectively.

Exelon calculates the amount of 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, 2016 were 7.30% and 6.02%, respectively, compared to an expected long-term return assumption of 7.00% and 6.71%, respectively.

Discount Rate

The discount rate used to determine the majority of the December 31, 2016 pension and other postretirement benefit obligations was 4.04%, representing a weighted-average of the rate for the majority of pension and other postretirement benefit plans. At December 31, 2016 and 2015, for both Exelon and PHI, 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 future benefit distribution amounts 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 valuation at year end are also used to determine the cost for the following year. Exelon used discount rates ranging from 3.66% to 4.17% to estimate its 2017 pension and other postretirement benefit costs.

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 5.50% for 2016, decreasing to an ultimate health care cost trend rate of 5.00% in 2017 for the majority of its plans.

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 determining plan funding requirements pursuant to ERISA (referred to as RP-2000). Exelon is utilizing the Scale BB 2-Dimensional improvement scale with long-term improvements of 0.75% for its mortality improvement assumption. The mortality assumption is supported by an actuarial experience study on Exelon s plan participants performed in 2014.

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 2016 cost:				
Discount rate [(a)]	0.5%	$ (65)	$ (16)	$ (81)
	(0.5)%	78	20	98
EROA	0.5%	(82)	(12)	(94)
	(0.5)%	82	12	94
Health care cost trend rate	1.00%	N/A	9	9
	(1.00)%	N/A	(8)	(8)
Change in benefit obligation at December 31, 2016:				
Discount rate [(a)]	0.5%	(1,119)	(250)	(1,369)
	(0.5)%	1,298	290	1,588
Health care cost trend rate	1.00%	N/A	105	105
	(1.00)%	N/A	(95)	(95)

(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.

Table of Contents

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 Exelon s defined benefit pension plan participants was 11.9 years, 11.9 years and 11.8 years for the years ended December 31, 2016, 2015 and 2014, respectively. For the predecessor periods, the average remaining service period of PHI s defined benefit plans was approximately 11 years for both 2015 and 2014.

For other postretirement benefits, Exelon amortizes its unrecognized prior service costs over participants average remaining service period to benefit eligibility age and amortizes its transition obligations and certain actuarial gains and losses over participants average remaining service period to expected retirement. The average remaining service period of postretirement benefit plan participants related to benefit eligibility age was 9.0 years, 10.8 years and 9.1 years for the years ended December 31, 2016, 2015 and 2014, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 9.7 years, 9.7 years and 10.1 years for the years ended December 31, 2016, 2015 and 2014, respectively. For the predecessor periods, the average remaining service period of PHI s other postretirement benefit plans was approximately 11 years for both 2015 and 2014.

Regulatory Accounting (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

Exelon and the Utility Registrants account for their regulated electric and gas operations in accordance with the authoritative guidance, which requires Exelon and the Utility Registrants 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, 2016, Exelon and the Utility Registrants have concluded that the operations of each such Registrant meet the criteria to apply the authoritative guidance. If it is concluded in a future period that a separable portion of operations no longer meets the criteria of this guidance, Exelon and the Utility Registrants would be required to eliminate any associated regulatory assets and liabilities and the impact would be recognized in the Consolidated Statements of Operations and Comprehensive Income 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 and the Utility Registrants.

For each regulatory jurisdiction in which they conduct business, Exelon and the Utility Registrants 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 each Registrant s jurisdictions, and factors such as changes in applicable regulatory and political environments. Furthermore, each Registrant makes 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, for 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, pursuant to EIMA, and FERC-approved

transmission formula rate tariffs for ComEd, BGE, Pepco, DPL and ACE. 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 each Registrant 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 and the Utility Registrants for regulatory assets and regulatory liabilities are ultimately different than actual regulatory outcomes, the impact on their results of operations, financial position, and cash flows could be material.

ACE has a recovery mechanism for purchased power costs associated with BGS. ACE records a deferred energy supply costs regulatory asset or regulatory liability for under or over-recovered costs that are expected to be recovered from or refunded to ACE customers, respectively. In the first quarter of 2016, ACE changed its method of accounting for determining under or over-recovered costs in this recovery mechanism to include unbilled revenues in the determination of under or over-recovered costs. ACE believes this change is preferable as it better reflects the economic impacts of dollar-for-dollar cost recovery mechanisms. ACE applied the change retrospectively. The impact of the change was a $12 million reduction to ACE s opening Retained earnings as of January 1, 2014 with a corresponding reduction to Regulatory assets. The impact of the change on Net income attributable to common shareholder was an increase of $2 million and $1 million for the years ended December 31, 2015 and December 31, 2014, respectively.

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

Accounting for Derivative Instruments (All Registrants)

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 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. Pepco has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and DCPSC. DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and the DPSC. DPL also uses derivatives to reduce natural gas commodity volatility and to limit its customers exposure to natural gas price fluctuations under a hedging program approved by the DPSC. ACE has contracts to procure BGS electric supply that are executed through a competitive procurement process approved by the NJBPU. ComEd, PECO, BGE, Pepco, DPL and ACE 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.

116

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 market liquidity as well as determining whether a contract has one or more underlyings and one or more notional amounts. 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. Generally, hedge accounting is not elected for commodity transactions. Economic hedges for commodities are recorded at fair value through earnings. 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 the Utility Registrants, changes in the fair value each period are recorded with a corresponding offsetting regulatory asset or liability if there is an ability to recover the associated costs.

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 under the PAPUC-approved DSP

program, most of PECO s natural gas supply agreements, all of BGE s full requirement contracts and natural gas supply agreements that are derivatives and certain Pepco, DPL and ACE full requirement contracts qualify for and are accounted for under 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 changes in market interest rates. To manage foreign exchange rate exposure

118

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 (All Registrants)

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 tax benefits to be recorded in the Registrants consolidated financial statements.

In the first quarter of 2016, PHI, Pepco, DPL and ACE changed their accounting principle for classification of interest on uncertain tax positions. PHI, Pepco, DPL and ACE have reclassified interest on uncertain tax positions as interest expense from income tax expense in the Consolidated Statements of Operations and Comprehensive Income. GAAP does not address the preferability of one acceptable method of accounting over the other for the classification of interest on uncertain tax positions. However, PHI, Pepco, DPL and ACE believe this change is preferable for comparability of their financial statements with the financial statements of the other Registrants in the combined filing, for consistency with FERC classification and for a more appropriate representation of the effective tax rate as they manage the settlement of uncertain tax positions and interest expense separately. PHI, Pepco, DPL and ACE applied the change retrospectively. The reclassification in the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2015 is $34 million and $4 million for PHI and Pepco, respectively, and for the year ended December 31, 2014 is $1 million for both Pepco and ACE. The impact on all other PHI Registrants for years ended December 31, 2015 and December 31, 2014 is less than $1 million.

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 evaluate for negative evidence that could indicate the Registrant s inability to realize its deferred tax assets, such as historical operating loss or tax credit carryforward expiration. Based on the combined assessment, the Registrants record valuation allowances for deferred tax assets when they conclude it is more-likely-than-not such benefit will not be realized in future periods.

119

Table of Contents

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including future 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, 2016 and 2015 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 (All Registrants)

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 and changes in technology, regulations and the requirements of local governmental authorities. Periodic studies are conducted at ComEd, PECO, BGE, Pepco, DPL and ACE 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 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information.

Other, Including Personal Injury Claims

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

Revenue Recognition (All Registrants)

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.

Table of Contents

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 commodity price risk management 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.

Unbilled Revenues

The determination of Generation s and the Utility Registrants 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 Distribution & Transmission Revenues

ComEd s EIMA distribution formula rate provides for annual reconciliations to the distribution revenue requirement. As of the balance sheet dates, ComEd has recorded its best estimates of the distribution revenue impact resulting from changes in rates that ComEd believes are probable of approval by the ICC in accordance with the formula rate mechanism.

ComEd s, BGE s, Pepco s, DPL s and ACE s FERC transmission formula rate tariffs provide for annual reconciliations to the transmission revenue requirements. As of the balance sheet dates, ComEd, BGE, Pepco, DPL and ACE have recorded the best estimate of their respective transmission revenue impact resulting from changes in rates that each Registrant believes are probable of approval by FERC in accordance with the formula rate mechanism.

Distribution and transmission formula rates require significant 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 reconciliation can be affected by, among other things, variances in costs incurred, investments made, allowed ROE, and actions by regulators or courts.

See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for more information on the potential impacts of the new revenue accounting standard effective for annual reporting periods beginning on or after December 15, 2017.

Allowance for Uncollectible Accounts (All Registrants)

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. At December 31, 2015, Pepco, DPL and ACE estimated the allowance for uncollectible accounts based on specific identification of material amounts at risk by customer and maintained a reserve based on their historical collection experience. At December 31, 2016, Pepco, DPL and ACE aligned the estimation of their allowance for uncollectible accounts to be consistent with ComEd, PECO and BGE, as described above. Risk segments represent a group of customers with similar credit quality indicators that are comprised 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. The Utility Registrant 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. Utility Registrants customer accounts are written off consistent with approved regulatory requirements. Utility Registrants allowances for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU regulations. 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, 2016, 2015 and 2014 set forth below include intercompany transactions, which are eliminated in Exelon s consolidated financial statements.

Table of Contents

Net Income (Loss) Attributable to Common Shareholders by Registrant

	For the Years Ended December 31, 2016	For the Years Ended December 31, 2015	Favorable (unfavorable) 2016 vs. 2015 variance	For the Year Ended December 31, 2014	Favorable (unfavorable) 2015 vs. 2014 variance
Exelon	$ 1,134	$ 2,269	$ (1,135)	$ 1,623	$ 646
Generation	496	1,372	(876)	835	537
ComEd	378	426	(48)	408	18
PECO	438	378	60	352	26
BGE	286	275	11	198	77
Pepco	42	187	(145)	171	16
DPL	(9)	76	(85)	104	(28)
ACE	(42)	40	(82)	46	(6)

	Successor	*Predecessor*			
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014	Favorable (unfavorable) 2015 vs. 2014 variance
PHI	$ (61)	$ 19	$ 327	$ 242	$ 85

Results of Operations Generation

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014 [a]	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$ 17,751	$ 19,135	$ (1,384)	$ 17,393	$ 1,742
Purchased power and fuel expense	8,830	10,021	1,191	9,925	(96)
Revenues net of purchased power and fuel expense [b]	8,921	9,114	(193)	7,468	1,646
Other operating expenses					
Operating and maintenance	5,641	5,308	(333)	5,566	258
Depreciation and amortization	1,879	1,054	(825)	967	(87)
Taxes other than income	506	489	(17)	465	(24)
Total other operating expenses	8,026	6,851	(1,175)	6,998	147
Equity in losses of unconsolidated affiliates				(20)	20

Gain (Loss) on sales of assets	(59)	12	(71)	437	(425)
Gain on consolidation and acquisition of businesses				289	(289)
Operating income	836	2,275	(1,439)	1,176	1,099
Other income and (deductions)					
Interest expense	(364)	(365)	1	(356)	(9)
Other, net	401	(60)	461	406	(466)
Total other income and (deductions)	37	(425)	462	50	(475)
Income before income taxes	873	1,850	(977)	1,226	624
Income taxes	290	502	212	207	(295)
Equity in losses of unconsolidated affiliates	(25)	(8)	(17)		(8)
Net income	558	1,340	(782)	1,019	321
Net income (loss) attributable to noncontrolling interests	62	(32)	94	184	(216)
Net income attributable to membership interest	$ 496	$ 1,372	$ (876)	$ 835	$ 537

(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 revenues net of purchased power and fuel expense. Generation believes that revenues net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenues 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, 2016 Compared to Year Ended December 31, 2015. Generation s net income attributable to membership interest decreased compared to the same period in 2015, primarily due to lower revenues net of purchased power and fuel expense, higher operating and maintenance expense, higher depreciation and amortization expense, and losses on sales of assets in 2016, partially offset by increased other income and decreased income tax expense. The decrease in revenues net of purchased power and fuel expense primarily relates to lower mark-to-market results in 2016 compared to 2015 and lower realized energy prices, partially offset by the Ginna Reliability Support Services Agreement and a decrease in outage days at higher capacity units despite an increase in overall outage days. The increase in operating and maintenance expense is primarily related to the impairment of Upstream assets and certain wind projects, and increased costs related to the implementation of the cost management program. The increase in depreciation and amortization expense is primarily related to accelerated depreciation and amortization expense related to the previous decision to early retire the Clinton and Quad Cities nuclear generating facilities, increased nuclear decommissioning amortization and increased depreciation expense due to ongoing capital expenditures. The increase in losses on sales of assets is primarily due to Generation s strategic decision to narrow the scope and scale of its growth and development activities. The increase in other income is primarily due to the change in realized and unrealized gains and losses on NDT funds.

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 SNF 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.

Revenues 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 Other: amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions; accelerated nuclear fuel amortization associated with the initial early retirement decision for Clinton and Quad Cities; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities using the measure of revenues 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 the Utility Registrants. 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.

Table of Contents

For the years ended December 31, 2016 compared to 2015 and December 31, 2015 compared to 2014, Generation s revenues net of purchased power and fuel expense by region were as follows:

			2016 vs. 2015			2015 vs. 2014	
	2016	2015	Variance	% Change	2014	Variance	% Change
Mid-Atlantic [(a)(b)(e)]	$ 3,317	$ 3,571	$ (254)	(7.1)%	$ 3,431	$ 140	4.1%
Midwest [(c)]	2,971	2,892	79	2.7%	2,599	293	11.3%
New England	438	461	(23)	(5.0)%	351	110	31.3%
New York [(a)(e)]	742	634	108	17.0%	483	151	31.3%
ERCOT	281	293	(12)	(4.1)%	317	(24)	(7.6)%
Other Power Regions	336	250	86	34.4%	327	(77)	(23.5)%
Total electric revenues net of purchased power and fuel expense	8,085	8,101	(16)	(0.2)%	7,508	593	7.9%
Proprietary Trading	15	1	14	n.m.	42	(41)	(97.6)%
Mark-to-market gains (losses)	(41)	257	(298)	(116.0)%	(591)	848	n.m.
Other [(d)]	862	755	107	14.2%	509	246	48.3%
Total revenue net of purchased power and fuel expense	$ 8,921	$ 9,114	$ (193)	(2.1)%	$ 7,468	$ 1,646	22.0%

(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. Results of transactions with Pepco, DPL, and ACE are included in the Mid-Atlantic region for the successor period of March 24, 2016 to December 31, 2016.

(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. Includes a $57 million decrease to RNF, an $8 million increase to RNF, and a $124 million decrease to RNF for the amortization of intangible assets related to commodity contracts recorded at fair value for the years ended December 31, 2016, 2015, and 2014, respectively, and accelerated nuclear fuel amortization associated with the initial early retirement of Clinton and Quad Cities as discussed in Note 9 Early Nuclear Plant Retirements of the Combined Notes to the Financial Statements of $60 million for the year ended December 31, 2016.

(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. See Note 27 Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Table of Contents

Generation s supply sources by region are summarized below:

Supply Source (GWh)	2016	2015	2016 vs. 2015 Variance	2016 vs. 2015 % Change	2014	2015 vs. 2014 Variance	2015 vs. 2014 % Change
Nuclear Generation [a]							
Mid-Atlantic	63,447	63,283	164	0.3%	58,809	4,474	7.6%
Midwest	94,668	93,422	1,246	1.3%	94,000	(578)	(0.6)%
New York	18,684	18,769	(85)	(0.5)%	13,645	5,124	37.6%
Total Nuclear Generation	176,799	175,474	1,325	0.8%	166,454	9,020	5.4%
Fossil and Renewables							
Mid-Atlantic	2,731	2,774	(43)	(1.6)%	11,025	(8,251)	(74.8)%
Midwest	1,488	1,547	(59)	(3.8)%	1,372	175	12.8%
New England	6,968	2,983	3,985	133.6%	5,233	(2,250)	(43.0)%
New York	3	3		%	4	(1)	(25.0)%
ERCOT	6,785	5,763	1,022	17.7%	7,164	(1,401)	(19.6)%
Other Power Regions	8,179	7,848	331	4.2%	7,955	(107)	(1.3)%
Total Fossil and Renewables	26,154	20,918	5,236	25.0%	32,753	(11,835)	(36.1)%
Purchased Power							
Mid-Atlantic	16,874	8,160	8,714	106.8%	6,082	2,078	34.2%
Midwest	2,255	2,325	(70)	(3.0)%	2,004	321	16.0%
New England	16,632	24,309	(7,677)	(31.6)%	12,354	11,955	96.8%
New York				%	2,857	(2,857)	(100.0)%
ERCOT	10,637	10,070	567	5.6%	8,651	1,419	16.4%
Other Power Regions	13,589	18,773	(5,184)	(27.6)%	14,795	3,978	26.9%
Total Purchased Power	59,987	63,637	(3,650)	(5.7)%	46,743	16,894	36.1%
Total Supply/Sales by Region [b]							
Mid-Atlantic [c]	83,052	74,217	8,835	11.9%	75,916	(1,699)	(2.2)%
Midwest [c]	98,411	97,294	1,117	1.1%	97,376	(82)	(0.1)%
New England	23,600	27,292	(3,692)	(13.5)%	17,587	9,705	55.2%
New York	18,687	18,772	(85)	(0.5)%	16,506	2,266	13.7%
ERCOT	17,422	15,833	1,589	10.0%	15,815	18	0.1%
Other Power Regions	21,768	26,621	(4,853)	(18.2)%	22,750	3,871	17.0%
Total Supply/Sales by Region	262,940	260,029	2,911	1.1%	245,950	14,079	5.7%

(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).

(b) Excludes physical proprietary trading volumes of 6,179 GWh, 7,310 GWh, and 10,571 GWh for the years ended December 31, 2016, 2015, and 2014, respectively.

(c)

Includes affiliate sales to PECO and BGE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region. As a result of the PHI Merger, includes affiliate sales to Pepco, DPL, and ACE in the Mid-Atlantic region for the successor period of March 24, 2016 to December 31, 2016.

Mid-Atlantic. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $254 million decrease in revenues net of purchased power and fuel expense in the Mid-Atlantic was primarily due to lower realized energy prices, decreased capacity prices and higher oil inventory write-downs in 2016, partially offset by increased load volumes served.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $140 million increase in revenues net of purchased power and fuel expense in the Mid-Atlantic 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

127

nuclear volumes, the cancellation of the DOE SNF 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.

Midwest. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $79 million increase in revenues net of purchased power and fuel expense in the Midwest was primarily due to decreased nuclear outage days and decreased nuclear fuel prices.

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

New England. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $23 million decrease in revenues net of purchased power and fuel expense in New England was primarily due to lower realized energy prices and higher oil inventory write-downs in 2016, partially offset by increased capacity prices.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $110 million increase in revenues net of purchased power and fuel expense in New England 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.

New York. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $108 million increase in revenues net of purchased power and fuel expense in New York was primarily due to the impact of the Ginna Reliability Support Service Agreement, partially offset by lower realized energy prices.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $151 million increase in revenues 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.

ERCOT. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $12 million decrease in revenues net of purchased power and fuel expense in ERCOT was primarily due to lower realized energy prices, partially offset by increased output from renewable assets.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $24 million decrease in revenues 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.

Other Power Regions. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $86 million increase in revenues net of purchased power and fuel expense in Other Power Regions was primarily due to higher realized energy prices.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $77 million decrease in revenues net of purchased power and fuel expense in Other Power Regions 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.

Proprietary Trading. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $14 million increase in revenues net of purchased power and fuel expense in Proprietary trading was primarily due to congestion activity.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $41 million decrease in revenues net of purchased power and fuel expense in Proprietary trading was primarily due to the absence of 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 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, 2016 Compared to Year Ended December 31, 2015. Mark-to-market losses on economic hedging activities were $41 million in 2016 compared to gains of $257 million in 2015.

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.

Other. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $107 million increase in other revenue net of purchased power and fuel was primarily due to revenue related to the inclusion of Pepco Energy Services results in 2016 and revenue related to energy efficiency projects, partially offset by the amortization of energy contracts recorded at fair value associated with prior acquisitions, and accelerated nuclear fuel amortization associated with the initial early retirement decision for Clinton and Quad Cities as discussed in Note 9 Early Nuclear Plant Retirements of the Combined Notes to the Financial Statements.

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.

Nuclear Fleet Capacity Factor

The following table presents nuclear fleet operating data for 2016, as compared to 2015 and 2014, 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 a 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.

	2016	2015	2014
Nuclear fleet capacity factor [(a)]	94.6%	93.7%	94.3%

(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.

Table of Contents

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The nuclear fleet capacity factor, which excludes Salem, increased in 2016 compared to 2015 primarily due to fewer refueling and non-refueling outage days. For 2016 and 2015, planned refueling outage days totaled 245 and 290, respectively, and non-refueling outage days totaled 63 and 82, respectively.

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.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2016 compared to 2015, consisted of the following:

	Increase (Decrease)
Impairment and related charges of certain generating assets [a]	$ 161
Merger and integration costs	27
Midwest Generation bankruptcy charges	10
ARO update [b]	(79)
Pension and non-pension postretirement benefits expense [c]	(42)
Corporate allocations [d]	(12)
Plant retirements and divestitures [e]	(50)
Accretion expense	(21)
Nuclear refueling outage costs, including the co-owned Salem plant [f]	(61)
Merger commitments	53
Labor, other benefits, contracting and materials [g]	185
Cost management program [h]	43
Curtailment of Generation growth and development activities [i]	24
Other	95
Increase in operating and maintenance expense	$ 333

(a) Reflects increased impairments in 2016 compared to 2015, primarily related to the impairments of certain Upstream assets and wind generating assets in 2016.
(b) Reflects a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units.
(c) Reflects the favorable impact of higher pension and OPEB discount rates.
(d) Reflects a decreased share of corporate allocated costs.
(e) Reflects the impact of the Generation s previous decision to early retire the Clinton and Quad cities nuclear facilities.
(f) Reflects the favorable impacts of decreased nuclear outages in 2016.
(g)

Reflects an increase of labor, other benefits, contracting and materials costs primarily due to increased contracting costs related to energy efficiency projects and the inclusion of Pepco Energy Services results in 2016. Also includes cost of sales of our other business activities that are not allocated to a region.

(h) Represents the 2016 severance expense and reorganization costs related to a cost management program.

(i) Reflects the one-time recognition for asset impairment charges pursuant to Generation s strategic decision in the fourth quarter of 2016 to narrow the scope and scale of its growth and development activities.

130

Table of Contents

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 2014 operating results include CENG s results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.
(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.

Depreciation and Amortization

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. Depreciation and amortization expense increased primarily due to accelerated depreciation and increased nuclear decommissioning amortization related to the previous decision to early retire the Clinton and Quad Cities nuclear facilities in 2016, and increased depreciation expense due to ongoing capital expenditures.

Excluding the impacts of future capital additions, Generation expects total annual depreciation for Clinton and Quad Cities in 2017 and future years will be consistent with the annual depreciation recognized prior to the June 2016 early retirement decision, with the impact on prospective depreciation of the reduction in the plants book values as a result of the accelerated depreciation recorded from June 2, 2016 to December 6, 2016, being essentially offset by the impact of shortening Clinton s expected economic useful life from the original 2046 date to the now expected 2027 date.

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.

Taxes Other Than Income

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The increase in taxes other than income was primarily due to an increase in gross receipts tax.

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.

Table of Contents

Equity in Losses of Unconsolidated Affiliates

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The year-over-year change in Equity in losses of unconsolidated affiliates is primarily the result of increased losses on equity investments.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The year-over-year change in Equity in 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, 2016 Compared to Year Ended December 31, 2015. The decrease in gain (loss) on sales of assets is primarily related to the one-time recognition for a loss on sale of assets pursuant to Generation s strategic decision in the fourth quarter of 2016 to narrow the scope and scale of its growth and development activities, partially offset by a gain associated with Generation s sale of the retired New Boston generating site in 2016.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The decrease in gain (loss) on sales of assets is 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.

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 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Interest expense on long-term debt	$ 8	$ 53
Interest expense on interest rate swaps	1	22
Interest expense on tax settlements	16	(37)
Other interest expense	(26)	(29)
(Decrease) increase in interest expense, net	$ (1)	$ 9

Other, Net

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The increase in Other, net primarily reflects the net increase 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 $80 million and $(22) million for the years ended December 31, 2016 and 2015,

132

Table of Contents

respectively, related to the contractual elimination of income tax expense associated with the NDT fund investments of the Regulatory Agreement Units. Refer to Note 16 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT fund investments.

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 years 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 16 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 2016, 2015 and 2014:

	2016	2015	2014
Net unrealized gains (losses) on decommissioning trust funds	$ 194	$ (197)	$ 134
Net realized gains on sale of decommissioning trust funds	35	66	77

Effective Income Tax Rate.

Generation s effective income tax rates for the years ended December 31, 2016, 2015 and 2014 were 33.2%, 27.1% and 16.9%, 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.

Results of Operations ComEd

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$ 5,254	$ 4,905	$ 349	$ 4,564	$ 341
Purchased power expense	1,458	1,319	(139)	1,177	(142)
Revenues net of purchased power expense [(a)(b)]	3,796	3,586	210	3,387	199
Other operating expenses					
Operating and maintenance	1,530	1,567	37	1,429	(138)
Depreciation and amortization	775	707	(68)	687	(20)
Taxes other than income	293	296	3	293	(3)
Total other operating expenses	2,598	2,570	(28)	2,409	(161)
Gain on sales of assets	7	1	6	2	(1)

Operating income	1,205	1,017	188	980	37
Other income and (deductions)					
Interest expense, net	(461)	(332)	(129)	(321)	(11)
Other, net	(65)	21	(86)	17	4
Total other income and (deductions)	(526)	(311)	(215)	(304)	(7)
Income before income taxes	679	706	(27)	676	30
Income taxes	301	280	(21)	268	(12)
Net income	$ 378	$ 426	$ (48)	$ 408	$ 18

133

(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, 2016 Compared to Year Ended December 31, 2015. ComEd s Net income for the year ended December 31, 2016 was lower than the same period in 2015 primarily due to the recognition of the penalty and the after-tax interest related to the Tax Court s decision on Exelon s like-kind exchange tax position, partially offset by increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE) and favorable weather.

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.

Revenues Net of Purchased Power Expense

There are certain drivers of Operating revenues that are fully offset by their impact on Purchased power expense, such as commodity procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on 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 revenues 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, 2016, 2015 and 2014, consisted of the following:

	For the Years Ended December 31,		
	2016	**2015**	**2014**
Electric	72%	76%	80%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2016, 2015 and 2014 consisted of the following:

	December 31, 2016		**December 31, 2015**		**December 31, 2014**	
	Number of customers	**% of total retail customers**	**Number of customers**	**% of total retail customers**	**Number of customers**	**% of total retail customers**
	1,502,900	38%	1,655,400	42%	2,426,900	63%

134

Table of Contents

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 revenues has increased as a result of the City of Chicago switching, but that increase is fully offset in Purchased power expense.

The changes in ComEd s Revenue net of purchased power expense for the year ended December 31, 2016 compared to the same period in 2015, and for the year ended December 31, 2015 compared to the same period in 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Weather	$ 54	$ (16)
Volume	(2)	(22)
Electric distribution revenue	69	180
Transmission revenue	97	48
Regulatory required programs	(31)	(1)
Uncollectible accounts recovery, net	(13)	27
Pricing and customer mix	14	(4)
Revenue subject to refund		9
Other	22	(22)
Increase in revenue net of purchased power	$ 210	$ 199

Weather. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as favorable weather conditions because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. For the year ended December 31, 2016, favorable weather conditions increased Operating revenues net of purchased power expense when compared to the prior years. For the year ended December 31, 2015, unfavorable weather conditions reduced Operating revenues 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, 2016, 2015 and 2014 consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	5,715	6,091	6,341	(6.2)%	(9.9)%
Cooling Degree-Days	1,157	806	842	43.5%	37.4%

Heading and Cooling Degree-Days	For the Years Ended December 31, 2015	2014	Normal	% Change 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)%

Volume. Revenue net of purchased power expense remained relatively consistent as a result of delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016, reflecting a consistent average usage per residential customer as compared to the same period in 2015. For the year ended December 31, 2015, Revenue net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, reflecting decreased average usage per residential customer and the impacts of energy efficiency programs, as compared to the same period in 2014.

Electric Distribution Revenue. EIMA provides for a performance-based formula rate, 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 and allowed ROE. 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. In addition, ComEd s allowed ROE is subject to reduction if ComEd does not deliver the reliability and customer service benefits to which it has committed over the ten-year life of the investment program. During the year ended December 31, 2016, electric distribution revenue increased $69 million, primarily due to increased capital investment and depreciation expense, partially offset by lower allowed ROE due to a decrease in treasury rates. 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. 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 the highest daily peak load, which is updated annually in January based on the prior calendar year. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. For the years ended December 31, 2016 and 2015, ComEd recorded increased transmission revenue due to increased capital investment, higher depreciation expense and increased highest daily peak load. 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 revenues 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, 2016, the increase in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to higher overall effective rates due to decreased usage across all major customer classes and change in customer mix. For the 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.

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.

Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease)	Year Ended December 31,		Increase (Decrease)
	2016	2015	2016 vs. 2015	2015	2014	2015 vs. 2014
Operating and maintenance expense baseline	$ 1,347	$ 1,353	$ (6)	$ 1,353	$ 1,214	$ 139
Operating and maintenance expense regulatory required programs [(a)]	183	214	(31)	214	215	(1)
Total operating and maintenance expense	$ 1,530	$ 1,567	$ (37)	$ 1,567	$ 1,429	$ 138

(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 revenues.

The changes in Operating and maintenance expense for year ended December 31, 2016, compared to the same period in 2015, and for the year ended December 31, 2015, compared to the same period in 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Baseline		
Labor, other benefits, contracting and materials [(a)]	$ 12	$ 31
Pension and non-pension postretirement benefits expense [(b)]	(24)	19
Storm-related costs	(9)	27
Uncollectible accounts expense provision [(c)]	5	(7)
Uncollectible accounts expense recovery, net [(c)]	(18)	34
BSC costs [(d)]	29	30
Other	(1)	5
	(6)	139
Regulatory required programs		

Energy efficiency and demand response programs		(31)		(1)
Increase in operating and maintenance expense	$	(37)	$	138

(a) Primarily reflects increased contracting costs related to preventative maintenance and other projects for the year ended December 31, 2015.

(b) Primarily reflects the favorable impact of higher assumed pension and OPEB discount rates for the year ended December 31, 2016 and the unfavorable impact of lower assumed pension and OPEB discount rates for the year ended December 31, 2015.

(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. ComEd recorded a net decrease and increase in 2016 and 2015, respectively, 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 revenues for the periods presented.

(d) Primarily reflects increased information technology support services from BSC during 2016 and 2015.

Depreciation and Amortization Expense

The increases in Depreciation and amortization expense for 2016 compared to 2015, and 2015 compared to 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Depreciation expense [(a)]	$ 58	$ 43
Regulatory asset amortization [(b)]	(5)	(28)
Other	15	5
Total increase	$ 68	$ 20

(a) Primarily reflects ongoing capital expenditures for the years ended December 31, 2016 and 2015.

(b) Primarily reflects a decrease in MGP regulatory asset amortization for the year ended December 31, 2015,

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 taxes remained relatively consistent for the year ended December 31, 2016 compared to the same period in 2015, and for the year ended December 31, 2015 compared to the same period in 2014.

Gain on Sale of Assets

Gain on sale of assets increased primarily due to the sale of land during the year ended December 31, 2016, compared to the same period in 2015. Gain on sale of assets remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014.

Interest Expense, Net

The increases in Interest expense, net, for the year ended 2016 compared to the same period in 2015, and for the year ended 2015 compared to the same period in 2014, consisted of the following:

	Increase (Decrease)	Increase (Decrease)

	2016 vs. 2015	2015 vs. 2014
Interest expense related to uncertain tax positions [(a)]	$ 109	$ 2
Interest expense on debt (including financing trusts) [(b)]	24	13
Other	(4)	(4)
Increase (decrease) in interest expense, net	$ 129	$ 11

(a) Primarily reflects the recognition of after-tax interest related to the Tax Court s decision on Exelon s like-kind exchange tax position in the third quarter of 2016. 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, 2016 and 2015. See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s debt obligations.

Table of Contents

Other, Net

The increase (decrease) in other, net, for the year ended 2016 compared to the same period in 2015, and for the year ended 2015 compared to the same period in 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Other income and deductions, net [(a)]	$ (94)	$ 2
AFUDC equity	9	2
Other	(1)	
Increase (decrease) in other, net	$ (86)	$ 4

(a) Primarily reflects the recognition of the penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position in the third quarter of 2016. See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

Effective Income Tax Rate

ComEd s effective income tax rates for the years ended December 31, 2016, 2015 and 2014, were 44.3%, 39.7% and 39.6%, respectively. The increase in the effective income tax rate for the year ended December 31, 2016 compared to the same period in 2015 is primarily due to the recognition of a non-deductible penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position in the third quarter of 2016. 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.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	**2016**	**2015**	**% Change 2016 vs. 2015**	**Weather-Normal % Change**	**2014**	**% Change 2015 vs. 2014**	**Weather-Normal % Change**
Retail Deliveries [(a)]							
Residential	27,790	26,496	4.9%	(0.6)%	27,230	(2.7)%	(1.5)%
Small commercial & industrial	31,975	31,717	0.8%	(0.3)%	32,146	(1.3)%	(0.9)%
Large commercial & industrial	27,842	27,210	2.3%	1.5%	27,847	(2.3)%	(2.0)%
Public authorities & electric railroads	1,298	1,309	(0.8)%	(0.8)%	1,358	(3.6)%	(2.6)%
Total retail deliveries	88,905	86,732	2.5%	0.2%	88,581	(2.1)%	(1.4)%

	As of December 31,		
Number of Electric Customers	**2016**	**2015**	**2014**
Residential	3,595,376	3,550,239	3,502,386
Small commercial & industrial	374,644	370,932	369,053
Large commercial & industrial	2,007	1,976	1,998
Public authorities & electric railroads	4,750	4,820	4,815
Total	3,976,777	3,927,967	3,878,252

Table of Contents

Electric Revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales [a]					
Residential	$ 2,597	$ 2,360	10.0%	$ 2,074	13.8%
Small commercial & industrial	1,316	1,337	(1.6)%	1,335	0.1%
Large commercial & industrial	462	443	4.3%	434	2.1%
Public authorities & electric railroads	45	42	7.1%	46	(8.7)%
Total retail	4,420	4,182	5.7%	3,889	7.5%
Other revenue [b]	834	723	15.4%	675	7.1%
Total electric revenue [c]	$ 5,254	$ 4,905	7.1%	$ 4,564	7.5%

(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.
(c) Includes operating revenues from affiliates totaling $15 million, $4 million, and $4 million for the years ended December 31, 2016, 2015, and 2014, respectively.

Results of Operations PECO

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$ 2,994	$ 3,032	$ (38)	$ 3,094	$ (62)
Purchased power and fuel	1,047	1,190	143	1,261	71
Revenues net of purchased power and fuel expense [a]	1,947	1,842	105	1,833	9
Other operating expenses					
Operating and maintenance	811	794	(17)	866	72
Depreciation and amortization	270	260	(10)	236	(24)
Taxes other than income	164	160	(4)	159	(1)
Total other operating expenses	1,245	1,214	(31)	1,261	47

Gain on sales of assets		2	(2)		2
Operating income	702	630	72	572	58
Other income and (deductions)					
Interest expense, net	(123)	(114)	(9)	(113)	(1)
Other, net	8	5	3	7	(2)
Total other income and (deductions)	(115)	(109)	(6)	(106)	(3)
Income before income taxes	587	521	66	466	55
Income taxes	149	143	(6)	114	(29)
Net income attributable to common shareholder	$ 438	$ 378	$ 60	$ 352	$ 26

(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 p